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Island Regulatory and Appeals Commission

Maritime Electric 2020-2021 Rate Application

Report date: October 14, 2020

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October 14, 2020

Dear Commissioner:

Re: Island Regulatory and Appeals Commission – Rate Application Filing Report

We enclose our report of the findings and observations with respect to the Island Regulatory and Appeals Commission – Rate Application Filing.

We would like to take this opportunity to thank the Commission, the Commission's legal counsel and Maritime Electric for their co-operation throughout this engagement.

Yours sincerely,

Grant Thornton LLP

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1. Executive summary

1.1. Project overview

This report was prepared by Grant Thornton LLP ("we", "us", or "Grant Thornton") under an engagement as a Consultant to the Island Regulatory and Appeals Commission ("IRAC" or "The Commission") for the review of Maritime Electric Corporation Inc. ("MECL" or "the Company") "Application for an Order approving changes to the Schedules of Rates effective March 1, 2020 and March 1, 2021 ("January Filing") as filed by MECL on January 31, 2020. This report is provided for the use of the Commission in evaluating the January Filing submitted by MECL.

1.2. Scope of work

Our report focuses on our procedures to review the proposed rates and document our findings and observations. Specifically, we have undertaken the following activities:

- Reviewed reports and underlying evidence filed by MECL as part of their January Filing;
- Reperformed calculations to determine the mathematical accuracy of the January Filing;
- Reviewed the January Filing for internal inconsistencies;
- Analysed and verified financial information presented by MECL in the January Filing;
- Prepared written interrogatories to MECL and reviewed their responses, and
- Investigated and reported on matters which are relevant to the Commission and fall within the general terms of reference.

Specific procedures are outlined in each section of this report to reflect the nature of the specific matter reviewed and the nature of the information filed by MECL. However, in general our procedures were comprised of:

- Enquiry and analytical procedures with respect to financial information in the Company's records;
- Assessing the reasonableness of the Company's explanations; and
- Assessing the Company's compliance with associated Commission Orders.

All tables presented throughout our report reflect the balances stated within the information filed by MECL and as a result may contain rounding differences due to presenting the information in millions of dollars.

1.3. Restrictions and limitations

Our scope of work is as set out throughout this report and reflect the scope that was agreed upon with the Commission. The procedures undertaken in the course of our review do not constitute an audit of MECL's financial information and consequently, we do not express an opinion on the financial information provided by MECL.

Information contained within this report may be considered commercially sensitive or confidential by the parties to the matter. Therefore, we defer to MECL and the Commission to determine if some of the information contained in our report should be treated as confidential. We acknowledge that our report will be communicated to the parties to the matter and may become a public document accessible through the Commission's website. We have given the Commission our consent to use our report for this purpose.

Our report is not to be reproduced or used for any purpose other than that outlined above without prior written permission in each specific instance. Grant Thornton LLP recognizes no responsibility whatsoever to any third party who may choose to rely on this report or other material provided to the Commission.

Unless stated otherwise within the body of this report, Grant Thornton LLP has relied upon information provided by MECL, the Commission and third-party sources in the preparation of this report, whom Grant Thornton LLP believe to be reliable. We are not guarantors of the information upon which we have relied in preparing the report and, except as stated, we have not audited or otherwise attempted to verify any of the underlying information or data contained in this report. We have made efforts to ensure a conservative, realistic and transparent approach, however, some of the analysis depends on the input from third parties whose opinions may influence the conclusions.

All analysis, information and recommendations contained herein are based upon the information made available to Grant Thornton LLP as of the date of this report and are subject to change without notice. We are under no obligation, to review and/or revise the contents of this report for events or information which becomes known to us after the date of this report.

1.4. Summary findings, observations and conclusions

The following represents a summary of our key findings and recommendations.

#	Report Section	Findings, observations and conclusions
1)	Energy sales forecast	Based on our review of MECL's energy sales forecast we have made the following findings and observations: • MECL's approach to load forecasting is an acceptable methodology within the industry; • During our review of energy sales forecast model provided by MECL we found no errors or omissions in the mathematical performance of the forecast; • The inputs and assumptions within the energy sales forecast model were supported; and • Based on MECL's explanations provided above, it appears that the variance between 2019 actuals and the 2019 forecast under the new methodology was largely driven by changes to the operational plans of a small number of customers including Canada's Island Garden, the Biovectra expansion, Cavendish Farms, as well as normal variances on HDD and CDD. These types of fluctuations can and will impact the future accuracy of MECL's forecast. Based on our procedures, nothing has come to our attention to indicate that the energy sales forecast for 2020 and 2021 is unreasonable.
2)	Revenue requirement	As a result of our procedures, nothing has come to our attention to indicate the components of revenue requirement for 2020 and 2021 as discussed within our report are unreasonable.
3)	Revenue shortfall	Based on our results of the above procedures, the Company's methodology to revenue shortfall does not appear unreasonable. However, we recommend that the final revenue shortfall is reviewed in the final determination of customer rates.
4)	CTGS Decommissioning	As a result of our procedures within our report we recalculated MECL's CTGS Variance Deferral at the end of 2021 of $9,654,524 as presented in Appendix 8 and did not note any exceptions. We recommend that the Commission consider denying MECL's request for the deferral amount and take up as a matter later, after the technical update and new depreciation study are completed.

#	Report Section	Findings, observations and conclusions
5)	Average rate base and return on rate base	Based on the results of our procedures, we did not note any discrepancies in the calculation of both the average rate base and return on average rate base. The proposed average rate base and return on rate base for 2020 and 2021 are in accordance with the methodology within the Electric Power Act and relevant Orders.
6)	Return on average common equity	We recommend that MECL file schedules in their next GRA that include the Company's weighted average cost of capital, average invested capital, average rate base, and return on rate base, in addition to their current schedules related to return on average common equity. The proposed average capital structure for 2020 and 2021 is consistent with the position approved by IRAC in Order UE 19-08. The calculations of Equity ratios are consistent with Appendix 9, Schedule 9-1 presented in the January 2020 filing (Amended II). Based on the results of our procedures, we did not note any discrepancies in the calculation of the forecast rate of return on average common equity for 2020 and 2021 and is consistent with the average common equity of 9.35% approved by IRAC in Order UE 19-08. The calculations of return on average common equity are consistent with Appendix 2 presented in the January 2020 filing (Amended II).
7)	Provincial cost recoverable	Based on the procedures performed in this section of our report we have the following findings and observations: 1. The PEI Accord recoverable amount is supported by the underlying debt amortization schedules. The rate rider calculation is mathematically correct and is based on MECL energy sales forecast. However, due to the structure of this cost recovery mechanism as a rate rider MECL has collected approximately $1.1 million more than the annual debt repayments associated with the Point Lepreau and the Dalhousie debt. We understand from discussion with MECL that the full amount including the overcollection is remitted to the PEIEC. However, the Commission should consider options for addressing the annual over or under collection based on actual kWh energy sales. 2. The PEIEC EE&C Plan funding has been calculated by MECL in accordance with their interpretation of the Commission's Orders as outlined in UE19-08. However, the intent of this order is unclear as Grant Thornton has interpreted the language in the order differently than MECL. We have determined that MECL has collected approximately $416,000 in 2019 related to the PEIEC EE&C Plan. Our position is that this balance should be remitted to the PEIEC thereby reducing MECL's forecasted rate rider for the 2020/2021 collection period. However, MECL has noted that if this approach is adopted the impact to rate payers will be $nil as the balance will come out of the RORA account and therefore the reduction in the Provincial Energy Efficiency Program rate rider will be offset by an equal adjustment to the RORA rate rider.

#	Report Section	Findings, observations and conclusions
8)	Energy cost adjustment mechanism	Based on the results of the procedures, nothing has come to our attention that the proposed ECAM base rate of $0.09225 per kWh and $0.09244 per kWh and ECAM charge rate of $0.0020 per kWh and $0.0001 per kWh for 2020 and 2021, respectively appear unreasonable. We did not note any discrepancies in the calculation of the forecast ECAM and components of the ECAM are internally consistent with the application's (i.e. energy supply costs, NPP) Appendix 3 presented in the January 2020 filing (Amended II) for the forecast years 2020 and 2021 and comply with Order UE 19-08. We can also verify that the Provincial Cost Recoverable is excluded from ECAM.
9)	Weather normalization mechanism	Based on our review and conversations with MECL on our findings, we did not note any further discrepancies and therefore conclude that the WNR variables for 2020 above is in accordance with the approved definition of the Weather Normalization Reserve other than the MWh per HDD Coefficient. Our recalculation found this variable to be 0.16 less at 67.91. Based on our calculation of monthly WNR adjustments, we did not note any exceptions outside of the $479 adjustment balance owning to customers as at December 31, 2019 and the $7,320 recoverable from customers to be carried into January 2020 according to MECL.
10)	Rate of return adjustment	We recommend the Commission consider whether a change is required in how interest is to be charged on RORA, and more specifically whether the short term borrowing rate is an appropriate rate to be charged given that RORA is a component of rate base where its components earn (or pay) a return based on the Company's WACC (or return on average rate base). Based on the results of the procedures, we find that the RORA balances from the 2016 to 2019 period were mathematically correct and in compliance with Commission Orders. We recalculated the proposed RORA refund rate rider of $0.0055 per kWh and found no exceptions.
11)	Proposed revenue from rates	Based on our procedures nothing has come to our attention to indicate that the forecast gross electric revenues from rates for 2020 and 2021 appear unreasonable. Based on our procedures we find that the revenue requirement proposed by the Company is calculated based up on the Schedule of Rates filed in Appendix 1 effective March 1, 2020 as outlined in the January 2020 filing (Amended II).
12)	Amortization rates	Based on our review, amortization expenses presented by MECL for 2020 and 2021 forecasts are calculated using the 2017 Depreciation Study recommended rates. Furthermore, we recalculated the amortization expenses for the forecast years without identifying any material errors and conclude that the amortization expense is calculated in accordance with the rates prescribed in the 2017 Deprecation Study.
13)	General rules and regulations	From our analysis we have determined that MECL has appropriately implemented and are currently complying with the amended General Rules and Regulations which were approved in order UE19-08. Based on our review of the large industrial customers' energy sales and revenue, we did not note any material exceptions and MECL is in accordance with the GRR.

#	Report Section	Findings, observations and conclusions
14)	Options	In this section we review MECL rate impact on customers under various scenarios. Based on our review, we found no exceptions or omissions in MECL's analysis of the impact. However, we understand that MECL intends to provide further calculations should some of these options be combined based on the Commission direction.

2. Energy sales forecast

2.1. Background

The energy sales forecast is the basis for the short-term and long-term energy supply planning process for MECL. The purpose of the sales forecast is to calculate the total energy required to serve based on the associated costs.

In the November 2018 GRA filing, the forecast was based on a sales regression analysis which reflects several variables such as population growth and changes in Consumer Price Index. MECL's management indicated that they conducted a review of trends of historical energy sales forecast, which included a two-year average growth rate calculation and an analysis of year-to-date growth over the previous period. In July 2019 the Company updated their GRA filing which included changes to its sales forecast and methodology.

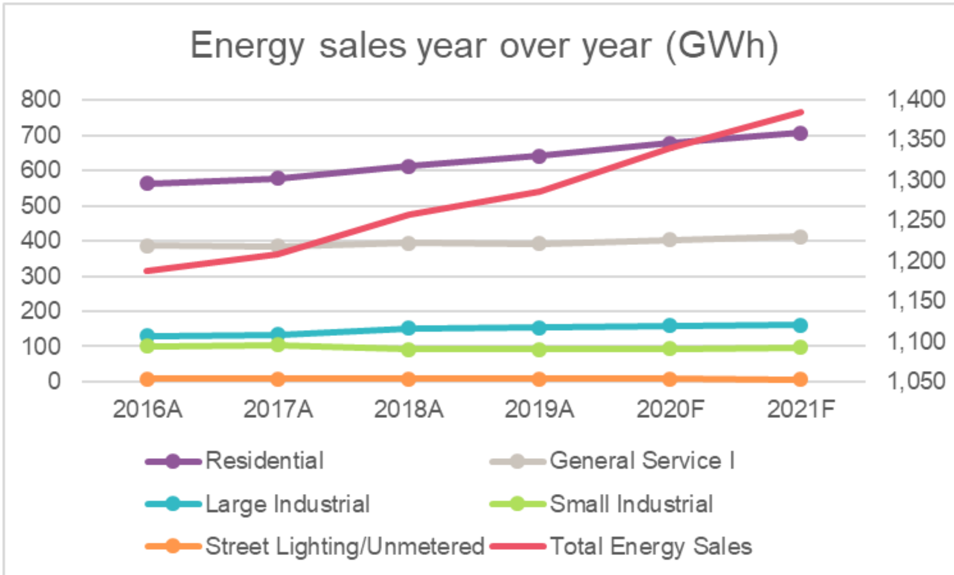
In Order UE19-08 the Commission stated that for several reasons (i.e.: significant increases, provided days before the hearing, impact on overall revenue requirement, change in load forecast methodology) they are not satisfied with the Company's forecasts as stated in Section 4 "Rates", paragraph #71:

> *"For all of these reasons, the Commission is not satisfied that the Company's forecasts as presented in this Application, and as revised on July 31, 2019, are reasonable, accurate or reliable. As such, the Commission is not prepared to approve the rates that are derived from those forecasts."*

In response to UE19-08 the Company filed (and subsequently amended) updated financial schedules for the Commissions consideration on January 31, 2020. This portion of our report refers to the January 2020 filing as amended on February 14, 2020 (the January 31, 2020 filing (Amended II)).

The following table illustrates the total energy sales actuals from 2016 to 2019 and MECL's January 2020 filing (Amended II) of the forecast for 2020 and 2021:

	Energy Sales (GWh)					
Customer Class	**2016A**	**2017A**	**2018A**	**2019A**	**2020F**	**2021F**
Residential	563.5	577.0	612.8	641.0	676.7	707.4
General Service I	386.8	384.9	393.6	392.8	403.2	412.6
Large Industrial	129.9	133.6	151.7	154.0	159.5	161.0
Small Industrial	100.1	104.6	91.7	91.7	94.3	96.5
Street Lighting/Unmetered	8.2	7.9	7.6	7.4	7.3	7.0
Total Energy Sales	**1,188.4**	**1,208.0**	**1,257.4**	**1,286.9**	**1,341.0**	**1,384.5**
Year Over Year Increase (decrease)						
Residential		2%	6%	5%	6%	5%
General Service I		0%	2%	0%	3%	2%
Large Industrial		3%	14%	2%	4%	1%
Small Industrial		4%	-12%	0%	3%	2%
Street Lighting/Unmetered		-4%	-4%	-3%	-1%	-4%
Overall increase (decrease)		**2%**	**4%**	**2%**	**4%**	**3%**



The line graph above incorporates two vertical axes. The vertical axis on the left relates to each customer class's energy sales in GWh and the vertical axis on the right relates to total energy sales in GWh.

Based on the tables above, the 2020 and 2021 forecast are 4% and 3% higher than the 2019 actual energy sales forecast respectively. These increases will be discussed throughout this section of the report.

2.2. Procedures

Our procedures with respect to the assessment of MECL's energy sales forecast were directed towards the assessment of the reasonableness of the methodology used by the Company, the reasonableness of the underlying assumptions including the support of those assumptions. Specifically, the procedures we performed included the following:

- Reviewed the Company's energy sales forecast methodology for each customer class;
- Recalculated the energy sales forecast to determine mathematical accuracy of the output;
- Reviewed the input assumptions in the model for reasonableness and reliability of the underlying support;
- Compared the 2019 energy sales forecast submitted to the Commission in July 2019 Update to the actual energy sales for 2019 to consider accuracy of forecasting methods; and
- Reviewed the application for internal consistency (i.e. energy sales forecast and revenue requirement calculations).

2.3. Analysis – Energy Sales Forecast Methodology

In this section we reviewed the Company's energy sales forecast methodology by customer class.

2.3.1 Residential

According to MECL's rules and regulations the residential customer class is made up of customers who use electricity for domestic living purposes, farms, churches, seasonal dwellings etc. The energy sales within this class makes up approximately half of the total energy sales for the Company.

We asked the Company to explain and support how the new methodology would be considered best practice within the utility industry. The following was their response:

> *"The Company considers it best practice to look at current economic indicators/trends in its service area and consider how these will impact the company's business and adjust the forecast accordingly. The new methodology for Residential sales was developed to better reflect the current PEI economy.*
>
> *For most of this decade, MECL was seeing increasing penetration of electric space heating, based on information provided by customers when applying for new residential services and anecdotally. The previous methodology for Residential sales modelled the increase in electricity sales for space heating as a function of the relative prices of electricity and furnace oil.*
>
> *With electricity having reached a penetration of greater than 80% for space heating, and a recent increase in housing starts, the previous approach was viewed as being no longer useful for Residential sales. Instead, a new methodology was developed, with housing starts as the main driver. The April 2019 load forecast is the first forecast based on the new methodology for Residential sales."*

MECL's December 2019 forecast update incorporates housing starts which are estimated using a regression formula with increase in PEI population as the input variable. These estimated housing starts from 2020 onward are overall lower than the provided Conference Board of Canada ("CBOC") December 5, 2019 forecast housing starts, therefore projecting a lower energy sales forecast for residential customers.

2.3.2 General Service

According to MECL's rules and regulations, general service customer class rate categories are for those customers who use electricity for all purposes other than those specifically covered under the residential, industrial, street lighting or unmetered service classes.

In response to our request MECL describes the methodology for energy sales forecasting as follows

> *"…The methodology consists of a single regression equation with three input variables. The input variables are: 1) Real PEI GDP, 2) Real price of electricity one year previous, and 3) Previous year actual energy sales. The regression equation is based on historical data for years 1998 to 2018."*

2.3.3 Large Industrial

These customers are defined by the Company within their Rates and General Rules and Regulations as rate categories for customers who use electricity mainly for manufacturing, assembly or processing of goods, or the extraction of raw materials.

During our review, we asked MECL to elaborate on their explanation of the large industrial customer's energy sales forecast. The following is the Company's response to our request:

> *"There are currently a total of seven customers in this rate class and the forecast for these customers is updated on a case by case basis. For new loads, the size and timing is described in comments in the respective year 2019 cells* [in excel workbook]. *This is based on information provided by the customer when applying for service, and used by MECL to determine the size of the transformer that will be needed to supply the load. For existing loads, the trend in usage in recent years is assumed to continue into the future."*

During our review of the January 2020 update energy sales, we noted a new industrial customer listed, Canada's Island Garden. The balance of the energy sales related to this customer is included within the residential customer class for final energy sales forecast figures. This presentation is inconsistent with the treatment of other industrial customers. Therefore, we asked MECL to provide an explanation for this treatment. In our request response MECL noted:

> *"Canada's Island Garden is a new cannabis grow operation that was expected to have a major expansion in mid-2019. This load is estimated to be 5 MW in size, with annual usage of approximately 30 million kWh. As such, it is a Large Industrial type load, not a Residential load. However, because farms are eligible for service under the Residential rate with no limitation on size of load, Canada's Island Garden is being served under the Residential rate. Changes to the Residential rate are being considered which are expected to eventually result in large farms being moved to other rate classes. In the meantime, Canada's Island Garden is being treated as a Large Industrial customer for purposes of developing the load forecast, with a subsequent adjustment to include it in Residential. The load for Canada's Island Garden is included in the July 31, 2019 Update forecast for Residential of 683.8 GWh and 706.9 GWh for 2020 and 2021, respectively."*

Furthermore, we asked MECL to provide an explanation for the process for request of new customer energy sales, the process in determining the reasonableness of the customer's projected energy sales forecast usage, and the consideration of possible expansions for customers which could increase demand or possibly updates within the customer's facilities for efficiencies, therefore decreased usage. In response, MECL provided the following:

> *"[*For new loads*], emails were initiated by a local engineering firm that did the electrical design on these two projects on behalf of the customer. As design engineer for these projects, the engineering firm has the information needed to estimate the size of the new load. Maritime Electric has a good working relationship with this engineering firm and has confidence in the quality of the work performed on behalf of the customers involved.*
>
> *The Company does assume that, for existing loads, the trends in usage in recent years will continue into the future unless there is evidence from other sources to the contrary. From time to time information comes available through media and other sources (such as requests from the customers themselves or as above, consultants acting on their behalf) which could lead to increased demand from expansion plans or updates within their facilities for efficiency purposes that could decrease usage. The impact of such information on the load forecast is considered as it occurs."*

2.3.4 Street Lighting

During our work we asked MECL to provide commentary and supporting documentation on the energy sales forecast inputs for the Street Lighting energy sales forecast within the excel model. The following was the Company's response:

> *"In 2015 MECL began a ten-year program to convert all Street Lighting to LED technology. The estimated reduction in electricity usage compared to the existing high-pressure sodium technology is 45%. The amount of sales under the LED conversion scenario…for 2024 (the final year of the conversion program) was estimated by multiplying the forecast for 2024 by 0.55 (i.e. 1 – 0.45). The sales for 2015 to 2023…were assumed to follow a uniform decline from the 2014 actual value to the 2024 forecast value.*
>
> *At the outset of the 10-year conversion program, the estimated reduction in electricity usage was 50%, based on a comparison of lighting fixtures with similar levels of light output. However, in 2018 a comparison of the actual sales for 2015, 2016 and 2017 with the forecast indicated that the reduction being achieved was 45%, and thus 45% has been used since then."*

The explanation provided by MECL agreed with the methodology used within the energy sales forecast provided by the Company.

2.4. MECL’s Historical Forecast Accuracy

We reviewed MECL’s historical forecasts compared to actual energy sales for the period to determine the accuracy of their forecasting. The table below summarizes total energy sales forecasts for each of the forecasts that were submitted to the Commission during this rate setting process.

	Energy Sales Forecasts (GWh)					
Source	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2016 GRA	1,193.8	1,218.5	1,242.6	-	-	-
November 2018 GRA	-	-	1,234.9	1,267.0	1,300.8	1,321.3
July 2019 Updates	-	-	-	1,305.5	1,356.2	1,384.5
January 2020 Updates	-	-	-	-	1,341.0	1,384.5
Final Energy Sales Forecast	**1,193.8**	**1,218.5**	**1,234.9**	**1,305.5**	**1,341.0**	**1,384.5**

The table below compares actual energy sales for 2019 to the forecast presented in the November 2018 GRA under MECL’s old forecast methodology.

	Energy Sales (GWh)			
	2019F Nov 2018 GRA	**2019A**	**Difference**	
Residential	620.7	641.0	20.3	3%
General Service I	389.7	392.8	3.1	1%
Large Industrial	154.7	154.0	(0.7)	0%
Small Industrial	94.4	91.7	(2.7)	-3%
Street Lighting/Unmetered	7.5	7.4	(0.1)	-1%
Total Energy Sales	**1,267.0**	**1,286.9**	**19.9**	**2%**

Actual energy sales for the period were approximately 20 GWh greater than the forecast that was presented, reflecting a 2% variance above forecast.

We also considered the accuracy of MECL’s new forecast methodology by comparing the actual energy sales for 2019 to the forecast presented in the July 2019 update filing. The table below reflects the variance between actual and forecast under MECL’s new forecast methodology.

	Energy Sales (GWh)			
	2019F July 2019 Update	**2019A**	**Difference**	
Residential	645.7	641.0	(4.7)	-1%
General Service I	399.9	392.8	(7.1)	-2%
Large Industrial	157.1	154.0	(3.1)	-2%
Small Industrial	95.3	91.7	(3.6)	-4%
Street Lighting/Unmetered	7.5	7.4	(0.1)	-1%
Total Energy Sales	**1,305.5**	**1,286.9**	**(18.6)**	**-1%**

Actual energy sales for the period were approximately 19 GWh less than the forecast that was presented, reflecting a 1% variance below forecast., which does not appear unreasonable. During our review we requested explanations for energy sales variances by customer class and obtained the following explanations:

1) **Residential** – The decrease of 4.7 GWh is primarily due to the customer Canada’s Island Garden cannabis load expected to be 17.0 GWh, but actual was 0.5 GWh due to startup delays. This was primarily offset by higher than average Heating Degree Days (“HDD”) in 2019, where HDD below 18 C were 4,640 for 2019, compared to 10-year average of 4,388 for 2009 to 2018, which increased energy sales by 14.3 GWh (difference of 252 HDD multiplied by the residential heating load coefficient of 56.8 MWh / HDD).

2) **General Service** – The decrease of 7.1 GWh is primarily due to cooling degree days ("CDD") above 18 C was 128 days for 2019. At 12 CDD below average, this accounts for 1.0 GWh of the shortfall. Additionally, previous year's sales are one of the regression equation independent variables, with a coefficient of 0.6 incorporated within the regression equation. As a result, a higher than average cooling load of 5.8 GWh in 2018 provides an upward forecast trend of 5.8 GWh times by the 0.6 coefficient to give you 3.5 GWh increase for 2019 energy sales.

3) **Large Industrial** – The decrease of 3.1 GWh is primarily due to the expected increase of 5.3 GWh for Biovectra expansion not occurring with a one-year delay in project. This was partially offset by Cavendish Farms customer load being 3.0 GWh higher than forecast.

4) **Small Industrial** – The decrease of 3.6 GWh is primarily due to at the end of Q1 of 2019, sales were up 4.1% over plan and 7.3% over Q1 of 2018. The forecast that was used in the July 31 update was prepared in April 2019 reflecting this increase, this forecast for small industrial sales was supported by the year to date sales for Q1.

5) **Street Lighting** – The decrease of 0.1 GWh is due to the 10-year program to convert all street lighting to LED technology for efficiency.

Based on MECL's explanations above it appears that the variance between 2019 actuals and the 2019 forecast under the new methodology was largely driven by changes to the operational plans of a small number of customers including Canada's Island Garden, the Biovectra expansion, Cavendish Farms, as well as normal variances on HDD and CDD.

2.5. Review of MECL's Forecast for 2020 and 2021

In addition to the review of the methodology for the 2020 and 2021 we also performed variance analysis of the forecast by customer class. This has been summarized in the table below:

	Energy Sales (GWh)		
	2019A	**2020F**	**2021F**
Residential	641.0	676.7	707.4
General Service I	392.8	403.2	412.6
Large Industrial	154.0	159.5	161.0
Small Industrial	91.7	94.3	96.5
Street Lighting/Unmetered	7.4	7.3	7.0
Total Energy Sales	**1,286.9**	**1,341.0**	**1,384.5**
Year over year increase (decrease) (GWh)			
Residential		35.7	30.7
General Service I		10.4	9.4
Large Industrial		5.5	1.5
Small Industrial		2.6	2.2
Street Lighting/Unmetered		(0.1)	(0.3)
Total increase (decrease) GWh		**54.1**	**43.5**
Total increase (decrease) %		**4%**	**3%**

In addition to a year over year analysis we also considered the reasonability of the cumulative variance over the two-year rate period within this application.

	Energy Sales (GWh)				
	2019A	2020F	2021F	Cumulative Variance 2021F - 2019A	
Residential	641.0	676.7	707.4	66.4	10%
General Service I	392.8	403.2	412.6	19.8	5%
Large Industrial	154.0	159.5	161.0	7.0	5%
Small Industrial	91.7	94.3	96.5	4.8	5%
Street Lighting/Unmetered	7.4	7.3	7.0	(0.4)	-5%
Total Energy Sales	**1,286.9**	**1,341.0**	**1,384.5**	**97.6**	**8%**

For each customer class MECL provided the following explanation of the cumulative variances from the 2021 forecasted energy sales in comparison to the 2019 actual energy sales.

1) **Residential** – the increase of 66.4 GWh from 2019 to 2021 is primarily due to the Canada's Island Garden customer's energy supply required, which is 31.5 GWh, in addition to the increase in housing starts within PEI.

2) **General Service** – the increase of 19.8 GWh from 2019 to 2021 is primarily due to the PEI real GDP prices increasing each year, based on the December 5, 2019 CBOC forecast.

3) **Large Industrial** – the increase of 7.0 GWh from 2019 to 2021 is primarily due to the customer Biovectra's energy forecast increasing approximately 6.0 GWh.

4) **Small Industrial** – the increase of 4.8 GWh from 2019 to 2021 is primarily due to the PEI real GDP prices increasing each year, based on the December 5, 2019 CBOC forecast.

5) **Street Lighting/Unmetered** – the decrease from 2019 to 2021 is due to the ten-year program started in 2015 which replaces higher use high pressure sodium and mercury vapour street lights with energy efficiency LED fixtures.

2.6. Findings and observations

Based on our review of MECL's energy sales forecast we have made the following findings and observations:

- MECL's approach to load forecasting is an acceptable methodology within the industry;
- During our review of energy sales forecast model provided by MECL we found no errors or omissions in the mathematical performance of the forecast;
- The inputs and assumptions within the energy sales forecast model were supported; and
- Based on MECL's explanations provided above, it appears that the variance between 2019 actuals and the 2019 forecast under the new methodology was largely driven by changes to the operational plans of a small number of customers including Canada's Island Garden, the Biovectra expansion, Cavendish Farms, as well as normal variances on HDD and CDD. These types of fluctuations can and will impact the future accuracy of MECL's forecast.

2.7. Conclusion

Based on our procedures, nothing has come to our attention to indicate that the energy sales forecast for 2020 and 2021 is unreasonable.

3. Revenue requirement

3.1. Background

Revenue requirement reflects MECL's calculation of the annual revenues required to cover both its forecast expenses and the approved rate of return. It is meant to cover only the Company's forecast annual cost to provide safe and reliable services to their customers. MECL's application has broken down their revenue requirement into the following categories:

- Operating expenses;
- Interest expense;
- Amortization on fixed assets;
- Amortization of regulatory balances;
- Income tax; and
- Return on equity.

Forecasting Methodology and Assumptions

We enquired of MECL's forecasted methodology for operating expenses and found that they forecast by expense type depending on the nature of the expense category. MECL grouped the forecast for operating expenses in two parts: (1) forecasted energy supply costs; (2) forecasted other costs. We have incorporated MECL's energy supply costs methodology description throughout this section of the report. The following describes MECL's overall forecast approach for other cost categories.

<u>Other Costs (ECC, non-fuel generation costs, T & D and General Costs):</u>

- Labour and transportation costs are based on the existing complement of approximately 183 FTEs with inflationary adjustments between 2.1% - 2.5%. In some cases, employees may be budgeted for redeployment to other departments as is the case for the generation department with the impending decommissioning of the Charlottetown Thermal Generating Station ("CTGS"). Like many employers, MECL has an aging workforce and in certain circumstances where long-term employees have indicated a timeline for retirement and the Company considers these positions require significant training, the Company includes a provision for transitional employees in its plan.

- Open Access Transmission Tariff ("OATT") costs are based on the forecast Network Service costs over the 2020-2021 period based on the OATT rates approved by the Commission effective August 1, 2018.

- Contractor labour is based on expected work requirements for services and estimated costs based on purchasing contracts with the contractor companies. Materials are estimated by the appropriate department manager based on historical experience and expected work requirements adjusted for inflation at a factor of 3%.

- Other costs can be broken down into two categories with respect to budgeting. The first category are known costs that are either fixed or known based on third party information such as:
    - Certain costs related to the new cable interconnection charges including the annual lease payments, schedule 9 charges from NB Power for interconnection facilities and the annual contribution to the cable contingency fund.
    - Transmission and Distribution property taxes are assessed at 1% of prior year revenue, the annual assessment from the Island Regulatory & Appeals Commission are based on an estimate provided by the Commission and Other Post Employment Benefit costs are based on an annual report provided by an external actuary. These costs are budgeted by the appropriate department manager based on historical experience and expected expenditures at the time the budget is prepared. Costs in this category include consulting, legal, professional fees, advertising, communications costs, printing costs, equipment rental, maintenance fees, meals, postage, travel, subscriptions, dues & fees, insurance, non-Transmission and Distribution property taxes, employee assistance

program costs and computer operating costs. The budget for these costs are estimated in current day dollars and escalated by an inflationary factor of 3%.

3.2. Procedures

Our procedures with respect to the MECL's revenue requirement calculations were directed towards the assessment of the reasonableness of the accuracy of the calculation, the reasonableness of the underlying assumptions including the support for those assumptions, and internal consistency between financial schedules included in the January 2020 filing (Amended II). Specifically, the procedures we performed included the following:

- Recalculated revenue requirement to determine mathematical accuracy of the financial schedules;
- Reviewed MECL's forecast methodology for components of the revenue requirement calculation including all expense categories;
- Completed an analytical review of variances between the 2019 forecast and 2019 actuals investigating any significant variances;
- Reviewed the January 2020 filing (Amended II) for internal consistency (i.e. revenue requirement components including operating expenditures); and
- Performed analytical procedures including trend analysis and investigated significant variances between historical expenses and forecast results for 2020 and 2021.

3.3. Review of variances between 2019 forecast / 2019 actual

The table below provides a summary and comparison of forecasted 2019 revenue requirement components from the November 2018 GRA filing to actual 2019 results as presented in the January 2020 filing (Amended II):

	2019F Nov 2018 GRA	2019A Jan 31, 2020 (Amended II)	2019A - 2019F	% Change
Operating Expenses (Net of ECAM)*	$ 153,120,200	$ 153,485,663	$ 365,463	0.24%
Interest Expense (including amortization of Debt Issue	12,637,300	12,901,422	264,122	2.09%
Amortization – Fixed Assets	25,871,500	23,337,238	(2,534,262)	-9.80%
Amortization – DSM Costs	167,000	157,198	(9,802)	-5.87%
Amortization – Lepreau Writedown	93,400	93,400	-	0.00%
Income Tax Expense	6,529,500	6,483,242	(46,258)	-0.71%
Return on Equity **	14,240,700	14,262,630	21,930	0.15%
Total	**$ 212,659,600**	**$ 210,720,793**	**$ (1,938,807)**	
Year Over Year Change ($)		**(1,938,807)**		
Year Over Year Change (%)		**-0.91%**		

*Excluding Fortis Inc. Costs
**Before Disallowable Costs

Overall, 2019 actual revenue requirement results were $1,938,807 less than the forecasted revenue requirement presented to the Commission in MECL's January 2020 filing (Amended II).

The following sections provide our analysis and comparison for larger component variances of the revenue requirement between the 2019 forecast in November 2018 GRA filing to actual 2019.

3.3.1 2019 Operating expenses net of ECAM

The table below provides a summary and comparison of forecasted operating expenses net of ECAM from the 2019 forecast included in the November 2018 GRA filing to actual 2019 results as presented in the January 2020 filing (Amended II):

	2019F Nov 2018 GRA	2019A Jan 31, 2020 (Amended II)	2019A - 2019F	% Change	Notes
Energy supply expenses	$ 128,543,600	$ 126,443,125	$ (2,100,475)	-1.63%	**Note 1**
Energy suppy expenses - other	889,300	828,144	(61,156)	-6.88%	
ECAM	(1,557,700)	464,059	2,021,759	-129.79%	**Note 2**
Distribution	4,814,200	5,032,505	218,305	4.53%	**Note 3**
Transmission	9,080,300	9,189,839	109,539	1.21%	
Transmission & distribution - other	2,231,600	2,293,834	62,234	2.79%	
General & administrative	9,379,300	9,484,755	105,455	1.12%	
Less: Amortization – DSM Costs	(167,000)	(157,198)	9,802	-5.87%	
Less: Amortization – Lepreau Writedown	(93,400)	(93,400)	-	0.00%	
Total	**$ 153,120,200**	**$ 153,485,663**	**$ 365,463**		
Year Over Year Change ($)		**365,463**			
Year Over Year Change (%)		**0.24%**			

Overall, 2019 actual operating expenses net of ECAM were $365,463 greater than the forecasted operating expenses net of ECAM presented to the Commission in MECL's November 2018 filing. Based on our review we noted the following variances:

- **Note 1** – Actual energy supply expenses in 2019 were approximately $2.1 million (2%) less than forecasted primarily due to Wind and Ancillary expenses were lower than forecast by approximately $0.7 million and $0.8 million respectively. In addition, Firm Energy Purchases were higher than forecast by approximately $4.9 million, which was offset by the PEI Energy Corporation Dalhousie and Lepreau Debt Repayment lower than forecast of approximately $4.8 million, since included as a rate rider.
- **Note 2** – Actual ECAM in 2019 was approximately $2.0 million (436%) greater than forecasted primarily due to actual energy supply expenses are approximately $2.1 million less than forecasted.
- **Note 3** – Actual distribution was approximately $0.2 million (4%) greater than forecasted primarily due to the Rights of Way distribution expenses.

3.3.2 2019 interest expense

The table below provides a summary and comparison of forecasted interest expense from the November 2018 GRA filing to actual 2019 results as presented in the January 2020 filing (Amended II):

	2019F Nov 2018 GRA	2019A Jan 31, 2020 (Amended II)	2019A - 2019F	% Change
Annual interest on long term debt				
22-Dec-00	$ 1,135,500	$ 1,135,500	-	0.00%
15-Jan-97	1,293,800	1,293,800	-	0.00%
03-Jul-96	1,784,000	1,784,000	-	0.00%
02-Apr-08	3,632,400	3,632,400	-	0.00%
05-Dec-11	1,474,500	1,474,500	-	0.00%
23-Aug-16	1,462,800	1,462,800	-	0.00%
07-Dec-18	1,700,000	1,659,200	(40,800)	-2.40%
Short term debt charges	568,500	920,651	352,151	61.94%
Amortization of financing charges	15,800	13,004	(2,796)	-17.70%
Allowance for funds	(430,000)	(474,433)	(44,433)	10.33%
Total	**$ 12,637,300**	**$ 12,901,422**	**$ 264,122**	
Year Over Year Change ($)		**264,122**		
Year Over Year Change (%)		**2.09%**		

Overall, 2019 actual interest expense was $264,122 greater than the forecasted revenue requirement presented to the Commission in MECL's November 2018 filing. Based on our review, this variance is primarily due to MECL using higher than forecasted use of short-term debt as seen above.

3.3.3 2019 amortization of fixed assets

The table below provides a summary and comparison of forecasted amortization of fixed assets from the November 2018 GRA filing to actual 2019 results as presented in the January 2020 filing (Amended II):

	2019F Nov 2018 GRA	2019A Jan 31, 2020 (Amended II)
Amortization – Fixed Assets	$ 25,871,500	$ 23,337,238
Year Over Year Change ($)		**(2,534,262)**
Year Over Year Change (%)		**-9.80%**

Overall, 2019 actual amortization from fixed assets was approximately $2.5 million less than forecasted in MECL's November 2018 filing. This variance is primarily related to the timing and approach to adopting the recommendations of the 2017 Depreciation Study; the November 2018 forecast prepared by MECL included the 2017 Depreciation Study rates (excluding the amortization reserve variance rate portion) while the Company's actual 2019 amortization used rates from the 2014 Depreciation Study in compliance with Order UE 19-08. Order UE19-08 notes the following:

- ***Paragraph 254*** *– MECL seeks to adopt the deprecation rates recommended in the 2017 Deprecation Study. MECL proposes that the depreciation rates be calculated and adopted as of January 1, 2019.*
- ***Paragraph 270*** *– The Commission, therefore, orders MECL to adopt all of the recommendations made by Gannett Fleming in the 2017 Deprecation Study. This includes the adoption of the proposed depreciation rates and amortization of the accumulated reserve variance for all assets. The depreciation rates and amortization of the accumulated reserve variance shall be adopted as of January 1, 2020 and shall be included in the Company's revenue requirement for rates effective March 1, 2020 and March 1, 2021.*

3.4. Review of forecasted revenue requirement 2020 & 2021

MECL's revenue requirement presented in the January 2020 filing (Amended II) has been summarized in the table below:

	2016A	2017A	2018A	2019A	2020F	2021F
Operating Expenses (Net of ECAM)*	$ 134,018,878	$ 138,579,065	$ 147,386,372	$ 153,485,663	$ 162,897,200	$ 169,336,300
Interest Expense (including amortization of Debt Issue	12,378,373	12,251,808	12,618,847	12,901,422	12,844,400	12,854,300
Amortization – Fixed Assets	20,942,072	21,802,450	22,583,378	23,337,238	28,572,100	26,202,300
Amortization – DSM Costs	-	327,676	524,050	157,198	127,400	166,600
Amortization – Lepreau Writedown	97,362	93,400	93,400	93,400	93,400	93,400
Amortization - Storm Deferral	-	-	-	-	3,002,900	-
Income Tax Expense	5,959,260	6,130,460	6,266,588	6,483,242	6,742,200	6,978,200
Return on Equity**	12,941,456	13,350,422	13,792,864	14,262,630	14,842,900	15,371,400
Total	**$ 186,337,401**	**$ 192,535,281**	**$ 203,265,499**	**$ 210,720,793**	**$ 229,122,500**	**$ 231,002,500**
Year Over Year Change ($)		**$ 6,197,880**	**$ 10,730,218**	**$ 7,455,294**	**$ 18,401,707**	**$ 1,880,000**
Year Over Year Change (%)		**3.33%**	**5.57%**	**3.67%**	**8.73%**	**0.82%**

*Excluding Fortis Inc. Costs
**Before Disallowable Costs

MECL's forecasted revenue requirement for 2020 reflects an increase of approximately $18.4 million (9%) with a $1.9 million (1%) increase forecasted for 2021. Our review consisted of a review of the methodology applied for appropriateness based on the nature of the expense and expense analytical procedures. When significant variances were noted we inquired with MECL and considered the reasonability of their response for each of the following components of the revenue requirement:

a) Operating expenses;
b) Interest expense;
c) Amortization – fixed assets;
d) Amortization – DSM Costs;
e) Amortization – Lepreau writedown;
f) Amortization – storm deferral: This balance relates to the proposed treatment of the deferred balance associated with Storm Dorian. This deferral was created in accordance with UE19-11;
g) Income tax expense; and
h) Return on equity: our analysis of this component has been outlined in section 6 of this report therefore no further discussion is included below.

3.4.1 Operating expenses (net of ECAM)

The operating expense net of ECAM line in the revenue requirement calculation groups MECL's operating expense (net of ECAM), and removes amortization of DSM costs, and amortization of the Lepreau write-down. The amortization of DSM costs and the amortization of the Point Lepreau write drown are deducted from operating expenses net of ECAM because they are originally included in energy supply expenses but are presented as separate line items on MECL's revenue requirement calculation. The following table summarizes these balances.

	2016A	2017A	2018A	2019A	2020F	2021F
Energy Supply Expenses	$ 110,893,928	$ 118,105,056	$ 125,133,696	$ 126,443,125	$ 133,276,100	$ 138,373,900
Energy Supply Expenses - Other	732,928	781,150	808,114	828,144	901,200	954,400
ECAM	(344,276)	(2,358,689)	(1,973,263)	464,059	330,000	(56,400)
Distribution	4,698,082	4,475,585	4,692,981	5,032,505	5,102,800	5,217,700
Transmission*	7,372,943	7,493,351	8,347,496	9,189,839	10,023,800	10,241,300
Transmission & Distribution - Other	2,039,529	2,055,982	2,174,700	2,293,834	2,343,800	2,501,500
General & Administrative **	8,723,106	8,447,706	8,820,098	9,484,755	11,140,300	12,363,900
Amortization – DSM Costs	-	(327,676)	(524,050)	(157,198)	(127,400)	(166,600)
Amortization – Lepreau Writedown	(97,362)	(93,400)	(93,400)	(93,400)	(93,400)	(93,400)
Total	**$ 134,018,878**	**$ 138,579,065**	**$ 147,386,372**	**$ 153,485,663**	**$ 162,897,200**	**$ 169,336,300**
Year Over Year Change ($)		**4,560,187**	**8,807,307**	**6,099,291**	**9,411,537**	**6,439,100**
Year Over Year Change (%)		**3.40%**	**6.36%**	**4.14%**	**6.13%**	**3.95%**

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

Operating expense has increased year over year from the 2016 actuals to the 2021 forecast at a rate that is in excess of inflation during this period. The following sections of our report analyze each of the key components included in the operating expense.

3.4.1.1 Energy supply expenses

The following table provides a summary of the expenses that are grouped in the energy supply expense category.

	2016A	2017A	2018A	2019A	2020F	2021F
Point Lepreau	$ 20,935,352	$ 23,980,233	$ 23,109,894	$ 24,442,271	$ 24,499,500	$ 24,611,900
EPA - Firm Energy Purchases	26,253,401	39,296,913	47,846,194	59,046,454	66,717,200	62,708,000
EPA - System Energy Purchases	32,803,402	21,812,357	19,533,804	8,724,769	5,376,400	3,906,100
Charlottetown Plant	2,879,000	2,585,034	2,208,221	1,440,381	1,256,900	1,334,600
Combustine Turbine #3	963,160	962,634	707,928	597,587	622,300	779,900
Borden-Carleton Plant	369,710	559,442	336,281	309,591	426,000	572,200
Energy Control Centre Operations	785,578	763,155	906,764	951,758	1,071,600	1,158,200
Wind	23,771,059	23,426,491	24,513,862	24,599,257	25,681,400	35,592,300
Ancillary Services	515,592	39,012	(577,620)	(2,818)	896,700	909,900
Other Purchases	(9,558)	10,073	(46,167)	(187)	-	-
NB Interconnection Facilities Rental & Transmission Services	1,529,870	4,248,636	5,977,085	6,083,464	6,507,300	6,540,800
Amortization of Deferred Charges	97,362	421,076	617,450	250,598	220,800	260,000
Total	**$ 110,893,928**	**$ 118,105,056**	**$ 125,133,696**	**$ 126,443,125**	**$ 133,276,100**	**$ 138,373,900**
Year Over Year Change ($)		**7,211,128**	**7,028,640**	**1,309,429**	**6,832,975**	**5,097,800**
Year Over Year Change (%)		**6.50%**	**5.95%**	**1.05%**	**5.40%**	**3.82%**

The methodology used for determining energy supply expenses is based on forecasted energy sales. Specifically, the supervisor of the energy control centre determines energy purchase requirements based on the sales forecasts, factoring in additional energy required for system losses and company use.

We have not reviewed the individual agreements for energy supply as this would have been beyond the scope of our assignment. However, to ensure we were equipped with sufficient background information to critically consider MECL's response to our various questions on the energy supply costs we obtained the following background information on the agreements from MECL from confidential exhibit GRA Multese IR-6 and IR-7. In addition to understanding the background we also performed year over year analytical procedures and considered the methodology that MECL presented for each of the significant energy supply categories. The results of our review have been outlined in the following sections.

Point Lepreau

MECL indicated that the Point Lepreau Participation Agreement provides a contractual entitlement to capacity and energy from NB Power's Point Lepreau Nuclear Generating Station ("Point Lepreau"), from March 29, 1994 to end life of the unit. The contract is a take-or-pay contract, and therefore it is scheduled first. The terms of the agreement are such that NB Power shall recover in all events all costs associated with the provision and generation of the power and energy to which MECL is entitled. This contract provides MECL with an Entitlement (not ownership) to 30 MW of the total 660MW capacity and associated energy from the generating unit under terms and conditions that are intended to ensure that NB Power recovers in all events all the associated costs. In effect, MECL pays owner's costs and assumes owner's risks.

The 2020 and 2021 forecasts are based on a budget provided by NB Nuclear to MECL in November 2019. The 2020 and 2021 forecast expense is comparable to the 2019 actual expense.

The table below summarizes year over year energy supply expenses associated with Point Lepreau.

	2016A	2017A	2018A	2019A	2020F	2021F
Point Lepreau	$ 20,935,352	$ 23,980,233	$ 23,109,894	$ 24,442,271	$ 24,499,500	$ 24,611,900
Year Over Year Change ($)		**3,044,881**	**(870,339)**	**1,332,377**	**57,229**	**112,400**
Year Over Year Change (%)		**14.54%**	**-3.63%**	**5.77%**	**0.23%**	**0.46%**

EPA - Firm Energy Purchases

MECL indicated that Firm Energy Purchases are scheduled as part of the Energy Purchase Agreement which allows for some limited flexibility in energy purchases versus annual energy forecasts provided to NB Energy Marketing ("NBEM"). Firm Energy Purchases are backed by capacity purchased from NBEM and secure energy is backed by MECL capacity (Combustion Turbine 3), which are used to supplement the Point Lepreau purchases to provide the base load requirement for Maritime Electric through the Energy Purchase Agreement.

The table below summarizes year over year energy supply expenses associated with the Energy Purchase Agreement (EPA) for Firm Energy Purchases.

	2016A	2017A	2018A	2019A	2020F	2021F
EPA - Firm Energy Purchases	$ 26,253,401	$ 39,296,913	$ 47,846,194	$ 59,046,454	$ 66,717,200	$ 62,708,000
Year Over Year Change ($)		**13,043,512**	**8,549,281**	**11,200,260**	**7,670,746**	**(4,009,200)**
Year Over Year Change (%)		**49.68%**	**21.76%**	**23.41%**	**12.99%**	**-6.01%**

We inquired of MECL the reason for the fluctuation. Per MECL, the increase in Firm Energy Purchases is due to an increase in capacity purchases from 115MW to 120MW for the 2020 calendar year as well as a delay of the new 30MW Wind Farm which was scheduled for commercial operation on September 1, 2020. The 30MW Wind Farm is now forecast to be in commercial operation as of January 1, 2021.

EPA - System Energy Purchases

The table below summarizes year over year energy supply expenses associated with the EPA for System Energy Purchases, which are non-firm purchases for MECL:

	2016A	2017A	2018A	2019A	2020F	2021F
EPA - System Energy Purchases	$ 32,803,402	$ 21,812,357	$ 19,533,804	$ 8,724,769	$ 5,376,400	$ 3,906,100
Year Over Year Change ($)		**(10,991,045)**	**(2,278,553)**	**(10,809,035)**	**(3,348,369)**	**(1,470,300)**
Year Over Year Change (%)		**-33.51%**	**-10.45%**	**-55.34%**	**-38.38%**	**-27.35%**

MECL has indicated that the balance of the Company's energy purchase requirements is met through System Energy Purchases and are made up of two components: Secure Energy and Assured Energy. Both energy components can be curtailed based upon predefined situations, with varying notice periods for each of the energy components. These products are capacity backed by on-Island MECL generation.

According to MECL, the decrease in System Energy Purchases is due to an increase in Firm Energy Purchases, as well as the new 30MW Wind Farm forecasted to be in commercial operation effective January 1, 2021.

Charlottetown and Borden-Carleton Plant

The table below summarizes year over year energy supply expenses associated with the Charlottetown Plant, Combustion Turbine #2 and the Corden-Carleton Plant.

	2016A	2017A	2018A	2019A	2020F	2021F
Charlottetown Plant	$ 2,879,000	$ 2,585,034	$ 2,208,221	$ 1,440,381	$ 1,256,900	$ 1,334,600
Combustine Turbine #3	963,160	962,634	707,928	597,587	622,300	779,900
Borden-Carleton Plant	369,710	559,442	336,281	309,591	426,000	572,200
Total	**$ 4,211,870**	**$ 4,107,110**	**$ 3,252,430**	**$ 2,347,559**	**$ 2,305,200**	**$ 2,686,700**
Year Over Year Change ($)		**189,732**	**(223,161)**	**(26,690)**	**116,409**	**146,200**
Year Over Year Change (%)		**51.32%**	**-39.89%**	**-7.94%**	**37.60%**	**34.32%**

MECL's generation facilities at Charlottetown and Borden-Carleton are forecast to continue their role as backup energy supply for system disturbances and energy supply issues associated with the supply agreements or transmission curtailments in New Brunswick. Generation fuel (including plant heating) is based on forward pricing for the required fuel supply (diesel or bunker C) to meet the generation for backup and/or testing of the facilities.

According to MECL there are two main drivers for the increase in forecasted costs for the Borden-Carleton Plant in 2020 and 2021 as described below:

- In 2019, the Borden Generation Station ("BGS") was forecast to generate 0.5 GWh, actual generation at the facility was 0.2 GWh. As a result, fuel costs incurred in 2019 were approximately $0.1 million lower than

- expected. In both 2020 and 2021, the BGS is expected to generate 0.6 GWh with a corresponding increase in fuel costs.
- Additionally, there has been a change in how superintendents' salaries for the production department are budgeted. Prior to 2019, all superintendents' salaries for the production department were charged to the CTGS superintendence account when in fact, superintendents are responsible for all three generation facilities (CTGS, CT3 and BGS). In 2019, the Company began allocating superintendents costs to the three facilities based on time required to run and maintain these facilities.

Wind

The table below summarizes year over year variances for the energy supply expenses associated with wind generation sources.

	2016A	2017A	2018A	2019A	2020F	2021F
Wind	$ 23,771,059	$ 23,426,491	$ 24,513,862	$ 24,599,257	$ 25,681,400	$ 35,592,300
Year Over Year Change ($)		**(344,568)**	**1,087,371**	**85,395**	**1,082,143**	**9,910,900**
Year Over Year Change (%)		**-1.45%**	**4.64%**	**0.35%**	**4.40%**	**38.59%**

MECL notes that wind contracts are take-or-pay arrangements. There is no specific capacity associated with any one wind facility for which MECL has a Power Purchase Agreement. Wind production in 2019 was 12.1 GWh less than expected resulting in costs approximately $0.9 million lower than budgeted. The energy budget for 2021 assumes that the PEI Energy Corporation ("PEIEC") new 30 MW wind farm will be in service January 1, 2021 resulting in an increase in wind production of 115 GWh and approximately $9.0 million in costs.

Ancillary Services

According to MECL's November 2018 GRA filing ancillary services include items such as load following, regulation, imbalance, spinning reserve, non-spinning reserve, reactive power supply and voltage control. MECL purchases Firm, Secure and Assured energy based on a schedule quantity submitted. Energy Imbalance charges are incurred when the actual MWh usage is either greater or less than the hourly scheduled quantity on the NB/PEI interface. MECL is required to submit a schedule an hour prior to the hour required. If there is a variation between the scheduled quantity in MW for the hour and the actual MW per hour usage, the difference positive or negative is multiplied by the Final Hourly Marginal Cost in New Brunswick and the amount is charged as Imbalance Energy. As this is a variation from the schedule to actual, there is no imbalance in the forecast energy costs. The table below summarizes year over year variances for ancillary services.

	2016A	2017A	2018A	2019A	2020F	2021F
Ancillary Services	$ 515,592	$ 39,012	$ (577,620)	$ (2,818)	$ 896,700	$ 909,900
Year Over Year Change ($)		**(476,580)**	**(616,632)**	**574,802**	**899,518**	**13,200**
Year Over Year Change (%)		**-92.43%**	**-1580.62%**	**-99.51%**	**-31920.44%**	**1.47%**

MECL has indicated that beginning on March 1, 2019 they will be required to purchase its 10 minute and 30-minute non-spinning reserve requirement from the New Brunswick System Operator ("NBP-SO") via New Brunswick Energy Marketing ("NBEM"). According to MECL beginning on March 1, 2019 under the new Energy Purchase Agreement ("EPA"), the 40 MW at the BGS is used to backstop the Assured Energy product for the Winter Period (November 1 to March 31) only. Prior to this, BGS was used to provide the Company's requirement of 10-minute and 30-minute non-spinning reserves. The Company is now required to purchase its 10-minute and 30-minute non-spinning reserve requirement from the New Brunswick System Operator resulting in the increase in forecast costs for 2019 thru 2021. 2019 actuals reflect 3 months of this change (March, November and December of 2019) and were offset by credits for imbalance energy.

NB Interconnection Facilities Rental & Transmission Services

MECL operates a 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. The table below summarizes year over year variances for NB Interconnection Facilities Rental & Transmission services.

	2016A	2017A	2018A	2019A	2020F	2021F
NB Interconnection Facilities Rental & Transmission Services	$ 1,529,870	$ 4,248,636	$ 5,977,085	$ 6,083,464	$ 6,507,300	$ 6,540,800
Year Over Year Change ($)		**2,718,766**	**1,728,449**	**106,379**	**423,836**	**33,500**
Year Over Year Change (%)		**177.71%**	**40.68%**	**1.78%**	**6.97%**	**0.51%**

Over the period from actual 2016 results to forecasted 2021 amounts there have been significant fluctuations in this account. We inquired of MECL the reason for the increase in the 2020 forecast for this expense over the 2019 actuals and they provided the following explanation: *"The primary reason for the increase in costs is the $375,000 annual contribution to the cable contingency fund. Since 2013, the Company has been collecting a rate rider from electricity customers of $0.00027/kWh through rates. In its Order approving the OATT in 2018, the Commission ordered that the amount be collected through the OATT. As no changes to rates (including the rider) were approved for 2019, 2020 is the first year to reflect this change in the filing update."*

Amortization of Deferred Charges

The table below summarizes year over year variances for the amortization of deferred charges. These deferrals include the following:

- Amortization of the Lepreau write-down
- Amortization of the DSM costs

	2016A	2017A	2018A	2019A	2020F	2021F
Amortization of Deferred Charges	$ 97,362	$ 421,076	$ 617,450	$ 250,598	$ 220,800	$ 260,000
Year Over Year Change ($)		**323,714**	**196,374**	**(366,852)**	**(29,798)**	**39,200**
Year Over Year Change (%)		**332.48%**	**46.64%**	**-59.41%**	**-11.89%**	**17.75%**

These amortizations are discussed in detail below.

3.4.1.2 Energy Supply Expenses Other

Other Energy Supply Expense has increased from $828,144 in 2019 actuals to $901,200 in the 2020 forecast with another increase to $954,400 in the 2021 forecast; netting a total increase of $126,256 in the period of two years. According to MECL, this change was due to a net change from 2019 actuals to 2021 forecasts of $64,140 for Insurance Expense, $19,137 for Property Tax, and $42,979 for Professional Development and Training.

3.4.1.3 ECAM

An analysis of the Energy Cost Adjustment Mechanism ("ECAM"), including fluctuations in the year over year balance is outlined below in section 8 of this report.

3.4.1.4 Distribution

The table below provides a breakdown of MECL's distribution expenses.

	2016A	2017A	2018A	2019A	2020F	2021F
Substations	$ 122,624	$ 113,103	$ 112,061	$ 101,197	$ 100,500	$ 103,200
Rights of Way **(Note1)**	1,640,174	1,431,043	1,271,836	1,596,499	1,415,600	1,435,700
Line Maintenance **(Note2)**	1,628,418	1,635,121	1,864,263	1,802,702	1,974,700	2,025,500
Line Control Devices	47,898	47,854	48,313	56,240	68,200	69,800
Transformers **(Note3)**	516,815	452,070	575,466	701,066	533,000	544,900
Meters	166,363	158,003	168,925	172,749	185,200	190,300
Communications Systems **(Note 4)**	172,411	212,842	196,253	160,462	266,500	273,100
Supervisory SCADA	77,128	105,279	105,535	89,399	128,200	131,300
Engineering	326,251	320,270	350,329	352,191	430,900	443,900
Total	**$4,698,082**	**$ 4,475,585**	**$ 4,692,981**	**$ 5,032,505**	**$ 5,102,800**	**$ 5,217,700**
Year Over Year Change ($)		**(222,497)**	**217,396**	**339,524**	**70,295**	**114,900**
Year Over Year Change (%)		**-4.74%**	**4.86%**	**7.23%**	**1.40%**	**2.25%**

Historically there has been some year over year volatility in this expense category. However, the forecasted growth in 2020 and 2021 over 2019 actuals (1% and 2% respectively) would reflect normal inflationary levels for the overall expense. However, we gathered the following explanations from MECL regarding some of the key accounts in this expense category:

- **Note 1** – MECL has indicated that in the fall of 2019, much of the right of way operations focus was on clean-up from Storm Dorian including removal of trees and branches damaged in the storm that pose a high risk to employee or public safety and/or future outages. This resulted in higher than forecast Distribution - Rights of Way costs and lower than forecast Transmission - Rights of Way costs in 2019. The forecast for 2020 and 2021 is based on historical experience for transmission and distribution Rights of Way costs.
- **Note 2** – MECL indicated the HSE Superintendent is transitioning to retirement and a replacement was hired in Q4 of 2019 to allow for transition of knowledge. In addition to this, one union full time equivalent ("FTE") was added to department 34 - construction services to meet growth in new services.
- **Note 3** – MECL noted actual transformer maintenance costs were significantly impacted by post-tropical storm Dorian. The proposed budget for 2020 and 2021 reflect expected costs based on historical experience excluding this major event.
- **Note 4** – According to MECL two union employees have been reassigned to technical services department (Communications Systems). The first was redeployed from the CTGS plant to technical services. One union FTE retired in 2019 from the engineering department and the position was reassigned to technical services to help meet resource requirements in that area.

3.4.1.5 Transmission

The table below provides a breakdown of MECL's transmission expenses.

	2016A	2017A	2018A	2019A	2020F	2021F
Substations	$ 45,058	$ 53,856	$ 63,538	$ 61,961	$ 75,600	$ 77,300
Rights of Way **(Note 1)**	74,126	701,576	270,134	142,757	388,100	399,800
Line Maintenance	247,142	284,820	333,140	290,383	309,000	318,000
Line Control Devices	56,312	54,106	63,640	46,726	74,700	76,300
Engineering	108,110	126,090	128,464	128,997	148,300	154,100
Open Access Transmission Tariff **(Note 2)**	6,842,195	6,272,903	7,488,580	8,519,015	9,028,100	9,215,800
Total	**$7,372,943**	**$ 7,493,351**	**$ 8,347,496**	**$ 9,189,839**	**$ 10,023,800**	**$ 10,241,300**
Year Over Year Change ($)		**120,408**	**854,145**	**842,343**	**833,961**	**217,500**
Year Over Year Change (%)		**1.63%**	**11.40%**	**10.09%**	**9.07%**	**2.17%**

Historically there has been some year over year volatility in this expense category. We have gathered the following explanations from MECL regarding some of the key accounts and variances in this expense category:

- **Note 1** – MECL has indicated that in the fall of 2019, much of operations focus was on clean-up from Dorian including removal of trees and branches damaged in the storm that pose a high risk to employee or public safety and/or future outages. This resulted in higher than forecast Distribution - Rights of Way costs and lower than forecast Transmission - Rights of Way costs in 2019. The forecast for 2020 and 2021 is based on historical experience for transmission and distribution Rights of Way costs.
- **Note 2** – MECL explained that the forecast OATT costs are based on the required network access for MECL to provide service to its distribution customers. At the time the forecast was prepared electricity sales were expected to increase by 4.00% in 2019, 3.88% in 2020 and 2.09% in 2021. However, actual sales increased by only 2.35% in 2019. As a result, 2019 transmission access charges were 1.65% lower than expected and results in a cumulative change in 2020 closer to 6%. Any change in MECL OATT charges year over year are offset by a corresponding change in OATT revenue and there is no rate impact to electric customers. OATT revenue is included in other revenue in Schedule 9-11. Further, we noticed the OATT revenue in Schedule 9-11 did not match the OATT expenses in Schedule 6-2. When asked, MECL provided the following answer:

  "The OATT revenue in Schedule 9-11 reflects the total revenue collected from all OATT customers on the Island (including Maritime Electric and all other transmission users on the Island).

  The costs represented in Schedule 6-2 included MECL's share of transmission costs based on its usage of the transmission system and the costs associated with administering the OATT.

The difference between the OATT revenue (Schedule 9-11) and MECL's costs (Schedule 6-2) is the Company's income from OATT derived from other customers. This income recovers those customers' share of the Company's costs associated with the transmission system (operations, depreciation, financing) that MECL's retail electricity customers would otherwise have to pay through rates.

Because MECL has multiple points of receipt of energy (NB, multiple wind farms) and multiple points of delivery (29 substations), the Company's transmission costs are largely charged through transmission network service. This is reflected in the Network Service line in Schedules 9-11 and 6-2.

Other MECL OATT customers have few points of receipt & delivery (1-3 in total) and therefore are charged for Point-to-Point service (Schedule 7 – firm energy & Schedule 8 – non-firm energy). Point-to-point service represents MECL's largest components of income from OATT."

3.4.1.6 Transmission and Distribution - Other

The table below provides a breakdown of MECL's transmission and distribution – other expenses.

	2016A	2017A	2018A	2019A	2020F	2021F
Insurance	104,427	117,034	140,184	143,717	$ 127,300	$ 131,100
Property Tax	1,868,844	1,881,192	1,943,372	2,049,826	2,127,800	2,279,000
Professional Development & Training	66,258	57,756	91,144	100,291	88,700	91,400
Total	**$2,039,529**	**$ 2,055,982**	**$ 2,174,700**	**$ 2,293,834**	**$ 2,343,800**	**$ 2,501,500**
Year Over Year Change ($)		**16,453**	**118,718**	**119,134**	**49,966**	**157,700**
Year Over Year Change (%)		**0.81%**	**5.77%**	**5.48%**	**2.18%**	**6.73%**

As seen above, other expenses related to Transmission and Distribution reflect one large fluctuation in property tax year over year. According to MECL, this fluctuation is caused by an increase in forecast revenue, which is the key component used to estimate property taxes. We asked MECL for the underlying calculations they use for property tax forecast which they provided along with the following response:

"The largest component of MECL's property tax is the tax assessment on Rights of Ways. This tax is assessed at 1% of the prior year gross revenue. The Company has attached a letter from the Province of PEI dated June 23, 2005 stating how the property tax on the Company's generating, transmission and distribution system is to be calculated."

The letter from the Province of PEI, indicated in MECL's response above, states *"the annual property tax on the generating, transmission, and distribution systems will be calculated on 1% of the company's total revenue in the year immediately preceding the taxation year."*

3.4.1.6 General and Administrative Expenses

The table presented below shows the summary of the January 2020 Update for General and Administrative Expenses which is a component of Operating Expenses during the time period 2019 to 2021 for the Company:

	2016A	2017A	2018A	2019A	2020F	2021F
Customer Service and Meter Reading **(Note 1)**	$ 2,058,663	$ 1,933,563	$ 1,929,987	$ 1,922,752	$ 2,203,600	$ 2,266,600
Finance and Accounting **(Note 2)**	1,393,344	1,367,720	1,382,047	1,392,343	1,472,700	1,523,600
Corporate Communications and Public Affairs **(Note 3)**	434,713	515,418	563,523	414,198	460,800	531,700
Information Technology **(Note 4)**	460,060	443,471	653,343	694,990	865,900	822,200
Regulation **(Note 5)**	743,681	649,891	822,800	1,064,830	949,000	1,066,800
Directors' Fees	242,017	251,962	334,545	365,327	420,100	432,700
General Property - Tax & Maintenance	681,983	637,708	686,281	692,068	733,400	755,400
Corporate Services and Support **(Note 6)**	2,708,645	2,647,973	2,447,572	2,938,247	4,034,800	4,964,900
Total	**$ 8,723,106**	**$ 8,447,706**	**$ 8,820,098**	**$ 9,484,755**	**$ 11,140,300**	**$ 12,363,900**
Year Over Year Change ($)		**(275,400)**	**372,392**	**664,657**	**1,655,545**	**1,223,600**
Year Over Year Change (%)		**-3.16%**	**4.41%**	**7.54%**	**17.45%**	**10.98%**

General and administrative expense is expected to grow by approximately $1.7 million in 2020 compared to 2019 and 2021 is forecast to increase by $1.2 million compared to 2020.

- **Note 1** – MECL has indicated that customer service and meter reading are forecasted to increase compared to 2019 due to lower than normal costs incurred in that year. In 2019, wages/benefits training costs for customer service were approximately $115,000 below budget due to parental leaves and retirements, as well as redeployments to other departments to cover sick leave and work load requirements. Furthermore, to this impact, the department will return to a full complement of customer service FTEs in 2020 and 2021. Also, in 2019, MECL stated that write-offs for uncollectable accounts and damage claims were down approximately $73,000 and $24,000 respectively compared to budget. Remaining variances in the year over year forecast for 2020 and 2021 are primarily due to 3% inflationary adjustments and updates to forecast costs of approximately $65,000 and $66,000 respectively.
- **Note 2** – As per MECL's response, forecasted finance and accounting costs were lower by approximately $70,000 in 2019 due to one full-time employee taking parental leave for 8 months. For 2020 and 2021, MECL stated that a full year is budgeted for finance and accounting costs.
- **Note 3** – As per MECL's response, corporate communications decreased in 2019 due to lower than expected donation levels of approximately $42,000. When asked about the 2019 decrease, MECL had the following response:
    - *"The Company forecasts annual donations based on historical spending to support requests from local charities and events across the Island. 2019 donation expense of $122K was unusually low compared with budget and prior years actuals (2018 - $164K, 2017 - $160K, 2016 - $148K). The Company's forecast for 2020 and 2021 reflects requests from local charities and events returning to historical levels."*
- **Note 4** – MECL notes that information technology is forecasted to increase in 2020 by approximately $170,000 due to the need for additional cyber security resources which will be acquired in 2020.
- **Note 5** – MECL notes that actual regulation costs in 2019 were approximately $242,000 higher than historical costs due to various studies, hearings, consulting, and other filing related costs. The regulatory costs in 2020 are forecasted to be lower due to less expected regulatory activity with 2021 forecasted to be higher than average as a result of the need for studies, hearings, consulting, and other filing related costs for the 2022-2024 rate setting activity.
- **Note 6** - Corporate Services and Support is forecasted to increase significantly in 2020 and 2021. Schedule 10-2 of the January 31, 2020 (Amended II) filing presents the breakdown of Corporate Services and Support. We inquired of MECL the reasoning for this and they indicated that it related to two main drivers as described below:
    - Employee future benefit costs are expected to increase related to a retiree health benefit plan which resulted in an actuarial gain on past service costs of approximately $10,000,000. This gain was amortized over 5 years (from 2015-2019). In 2019 the amortization of this gain equals approximately $2 million. In 2020, the employee future benefit costs are being partially offset by the gain amortization of $750,000. However, this reflects an approximate $1.3 million reduction from the gain amortization recognized in 2019 and therefore accounts for the forecasted increase in this expense. In 2021 employee future benefit costs are no longer being partially offset by the amortization of this historical gain.
    - Corporate services are forecasted to decrease by approximately $197,000 in 2020 followed by an increase of approximately $142,000 in 2021. MECL has indicated that the decrease in 2020 represents changes in executive compensation costs due to reductions in the relative valuation of variable compensations components. MECL has also indicated that the forecasted increase in 2021 is the result of one member of the executive team stepping through the final year of a three-year transition to 100% of the adopted pay band midpoint salary.

3.4.2 Interest expense

The interest costs which are part of the revenue requirement are associated with financing using short-term and long-term debt. The table presented below is the summary of the January 2020 filing (Amended II) for the interest expenses which is a component of revenue requirement during the time period 2019 to 2021 for the Company:

	2016A	2017A	2018A	2019A	2020F	2021F
Annual Interest Expense on LTD **(Note 1)**	$ 11,988,820	$ 12,065,450	$ 12,096,352	$ 12,442,200	$ 12,442,200	$ 12,442,200
Short Term Debt Charges **(Note 2)**	788,933	627,410	945,451	920,651	951,400	1,043,600
Allowance for Funds **(Note 3)**	(405,915)	(449,760)	(432,111)	(474,433)	(563,000)	(646,000)
Amortization of Financing Costs	6,535	8,708	9,155	13,004	13,800	14,500
Total	**$ 12,378,373**	**$ 12,251,808**	**$ 12,618,847**	**$ 12,901,422**	**$ 12,844,400**	**$ 12,854,300**
Year Over Year Change ($)		**(126,565)**	**367,039**	**282,575**	**(57,022)**	**9,900**
Year Over Year Change (%)		**-1.02%**	**3.00%**	**2.24%**	**-0.44%**	**0.08%**

We have noted that interest expense has been forecasted to remain stable in 2020 and 2021. However, during our review we noted the following:

- **Note 1** – annual interest expense on long term debt is stable in 2019 through 2021. This is different from the past when various debt instruments would have matured during the rate setting period. In Schedule 9-3 of the MECL application they have outlined the maturity dates of all long-term debt instruments. We have noted that none of the long-term debt is scheduled to mature and therefore interest on long term debt should remain stable for the duration of this rate setting period.
- **Note 2** – interest on short term debt is forecasted based on MECL's expected requirement for short term financing using the bank prime rate at the time the forecast was prepared. In this case MECL has indicated that the assumed interest rate was 3.95%. While this approach is not unreasonable, we did note that MECL's need for short term financing has increased in recent years. However, given that MECL's most recent long-term debt agreement has a stated interest rate of 4.148% the use of short-term financing is not unreasonable with a 3.95% interest rate.
- **Note 3** – the allowance for funds is an adjustment to interest expense to account for interest incurred on borrowing to fund long term capital projects. Allowance for Funds Used During Construction (AFUDC) is capitalized until the project is placed in operation by reducing the interest expense recorded on the income statement and increasing the capital cost of the property, plant or equipment that the financing is being used for. MECL has indicated that the increase in the credit for the allowance for funds line item is supported by MECL's changing capital plans over the years. This is consistent with the increase in capital expenditures for 2020 and 2021 as detailed in Schedule 9-7. The AFUDC for 2020 and 2021 of $563,000 and $646,000, respectively agrees to Schedule 9-7.

3.4.3 Amortization – Fixed Assets

In this section of our report we considered amortization on fixed assets purely from the perspective of the year over year changes and trends. This has been summarized in the table below.

	2016A	2017A	2018A	2019A	2020F	2021F
Amortization - Fixed Assets	**$ 20,942,072**	**$ 21,802,450**	**$ 22,583,378**	**$ 23,337,238**	**$ 28,572,100**	**$ 26,202,300**
Year Over Year Change ($)		**860,378**	**780,928**	**753,860**	**5,234,862**	**(2,369,800)**
Year Over Year Change (%)		**4.11%**	**3.58%**	**3.34%**	**22.43%**	**-8.29%**

From 2017 to 2019, amortization of fixed assets increased at a rate of approximately 4% year over year. However, in 2020 and 2021 the variance year over year varies as there was a new depreciation study completed with new deprecation rates effective in 2020 as part of this application and a variety of other matters being addressed in 2020. A more detailed discussion of this has been included in section 12 of this report.

3.4.4 Amortization – DSM Costs

Demand-side management ("DSM") is the practice of encouraging reduced energy consumption by rate payers. Utilities encourage a reduction of future load growth through various methods such as financial incentives, public education etc. MECL continues to play a role in DSM through public outreach and education however this topic has been evolving in recent years in PEI. The PEI Energy Corporation is focusing on building a self-sustaining energy system based on achievements in energy efficiency, conservation and renewable energy development in the Province. Therefore, in addition to the below DSM costs, MECL also collects and remits funds to PEI Energy Corporation related to provincial demand side management initiatives. These funds are outlined in section 12 of this report.

	2016A	2017A	2018A	2019A	2020F	2021F
Amortization - DSM Costs	$ -	$ 327,676	$ 524,050	$ 157,198	$ 127,400	$ 166,600
Year Over Year Change ($)		327,676	196,374	(366,852)	(29,798)	39,200
Year Over Year Change (%)		NA	59.93%	-70.00%	-18.96%	30.77%

In MECL's November 2018 GRA it states *"…this account also includes the amortization of the Company's annual public outreach and education expenditures under its Demand Side Management Plan ("DSM") as approved by IRAC under Order UE15-02 dated November 3, 2015. The amount amortized in each year represents the prior year's expenditures on the DSM programming subject to the maximum expenditure limit of $167,500 per year approved by the Commission…"*

We have reviewed UE15-02 and have noted that it was ordered that *"…public outreach and education component of the Plan, with an annual cost of $167,500 to be recovered through customer rates as a component of the Energy Cost Adjustment Mechanism, is hereby approved…".*

3.4.5 Amortization – Lepreau Write-down

The amortization of the Lepreau write down amount relates to the Company's recorded deferred asset in the amount of approximately $5.9 million with respect to the $450 million write-down of Point Lepreau Generating Station in 1998 by the New Brunswick Power Corporation, subject to an Entitlement Agreement between the two Companies. There have been no changes proposed in MECL's current application.

	2016A	2017A	2018A	2019A	2020F	2021F
Amortization - Lepreau Writedown	$ 97,362	$ 93,400	$ 93,400	$ 93,400	$ 93,400	$ 93,400
Year Over Year Change ($)		(3,962)	-	-	-	-
Year Over Year Change (%)		-4.07%	0.00%	0.00%	0.00%	0.00%

3.4.6 Amortization – Storm Deferral

In the fall of 2019 Tropical Storm Dorian made landfall on PEI and impacted MECL's customers Island-wide resulting in power outages for over 65,000 of MECL's 80,000 plus customers.

In Order UE19-11 the Commission noted that *"…the Commission accepts that MECL incurred storm restoration costs as a result of post-tropical storm Dorian in the total amount of $3,465,790. The Commission accepts the allocation of the storm restoration costs as being $388,110 in capital costs, $74,796 in retirement costs, and $3,002,884 in operating costs. The Commission approves the deferral of the operating costs incurred of $3,002,884 in relation to post-tropical storm Dorian for future recovery from ratepayers. ("Dorian operating costs"). The Commission shall determine the appropriate manner of recovering the Dorian operating costs as part of the electric rates, tolls and charges to be set effective March 1, 2020…"*

	2016A	2017A	2018A	2019A	2020F	2021F
Amortization - Storm Deferral	$ -	$ -	$ -	$ -	$ 3,002,900	$ -
Year Over Year Change ($)		-	-	-	3,002,900	(3,002,900)
Year Over Year Change (%)		NA	NA	NA	NA	-100.00%

MECL has proposed the full recovery of the costs related to Storm Dorian in 2020 by crediting against the Rate of Return Adjustment (RORA). This balance is presented in MECL schedules as a Storm Dorian Amortization cost of $3,002,900 with the same offsetting balance included in total revenues under Rate of Return Adjustment line in Schedule 9-12. This treatment is correct if the Commission approves the offsetting of Storm Dorian costs against RORA.

3.4.7 Income tax expense

Our review of income tax expense included a recalculation of income taxes based on substantively enacted corporate income tax rates for Federal and Provincial jurisdictions and an assessment of reasonableness based on forecast income and substantively enacted rates for 2018 and 2019 actuals as well as the forecast for 2020 and 2021.

	2018A	2019A	2020F	2021F
Earnings before income taxes	$ 20,059,452	$ 20,745,872	$ 21,585,100	$ 22,349,700
Income tax expense	$ 6,266,588	$ 6,483,242	$ 6,742,200	$ 6,978,200
Effective income tax rate	31.24%	31.25%	31.24%	31.22%
Statutory income tax rate	31.00%	31.00%	31.00%	31.00%

The Company's effective income tax rate is comparable to the statutory income tax rate in effect at the time of the Application for the proposed forecast. Based upon our analysis, income tax expense for forecast 2020 and 2021 appear consistent with substantively enacted corporate income tax rates and forecast increases in net income.

3.5. Conclusion

As a result of our procedures, nothing has come to our attention to indicate the components of revenue requirement for 2020 and 2021 as discussed above are unreasonable.

4. Revenue shortfall

4.1. Background

Revenue shortfall arises because customer rates, which are designed to meet the 2020 and 2021 revenue requirements, are not being implemented on March 1, 2020 as originally filed. MECL's revenue shortfall is calculated in contemplation of customer rates being implemented on September 1, 2020. Based on a September 1, 2020 implementation, customer rates designed to recover revenue requirement would result in a $1,525,240 shortfall in recovering the 2020 revenue requirement.

The Company has requested that the Commission consider a revenue shortfall deferral account to reflect the revenue lost in the interim period in order to meet its proposed revenue requirement. If approved the balance in the 2020 revenue shortfall deferral account would then be amortized and recovered through customer rates over the remaining rate setting period of September 1, 2020 to February 28, 2022, an 18-month period.

It is important to note that revenue is not earned at a consistent rate throughout the year, as demand for electricity varies depending on the time of year. The revenue requirement similarly is not distributed evenly throughout the year, as power supply costs vary depending on demand. As a result, simple proration of the total rates for the year compared to the total revenue requirement cannot apply in determining the revenue shortfall.

MECL methodology included in GT-RFI-2019-92 is described as a two-step process where in step one the revenue shortfall is calculated based on the delay of implementation of rates, with step two being the recalculation of the revenue requirement for 2020 and 2021 with the revenue shortfall deferral and recalculating basic rates required to recover the shortfall over the remaining rate setting period. As the shortfall changes, the rates for 2020 and 2021 also change, creating a circular element to the calculation.

4.2. Procedures

Our procedures with respect to MECL's requested revenue shortfall were focused on the accuracy of the calculation, the reasonableness of the underlying assumptions including the support for those assumptions, and internal consistency between financial schedules included in the January 2020 filing (Amended II). Specifically, the procedures we performed included the following:

- Recalculated revenue shortfall to determine mathematical accuracy of the financial model;
- Reviewed MECL's revenue shortfall methodology for components of the calculation (i.e.: rates and forecast kWh sales) considering reasonability; and,
- Reviewed MECL's revenue shortfall methodology for consistency with other jurisdictions.

4.3. Recalculation and Methodology Review

The table below provides a summary and comparison of the forecasted total revenues from rates for 2020 and 2021 in both the January 2020 filing (Amended II) and if proposed rates were approved and implemented on September 1, 2020:

	2020F	2021F
Jan 31, 2020 (Amended II)	$ 211,637,053	$ 217,785,028
Sept 1, 2020 Approved Rates	210,111,813	217,785,028
Revenue Shortfall	**$ 1,525,240**	**$ -**

For the purpose of the table above, MECL have assumed a September 1, 2020 rate implementation date, however the model can be applied for any implementation date approved by the Commission. The Company compared the revenue originally forecasted based on the proposed basic rate increase effective March 1, 2020, with no changes to the forecasted annual kWh sales or expenses from the January 31, 2020 (Amended II) filing.

The difference between the forecast revenue from basic rates for 2020 in the January 31, 2020 (Amended II) filing and the forecast revenue from basic rates as of the approved implementation date is the revenue shortfall which is shown above as $1,525,240 (thereby including existing rates in the calculation for the period from March to August 2020). This amount will be included within the revenue requirement for 2020 and 2021 as a deferral, which would be amortized and recovered over the rate setting period.

We did note that MECL used forecasts in its calculation of revenue shortfall for the period from March to August 2020 whereas actuals for kWh sales would be available for this period and could be incorporated into the Company's revenue shortfall calculation when available. We have not quantified the impact this would have on the revenue shortfall calculation.

We also note that the revenue shortfall calculation would need to be updated for any changes in other variables in the calculation including decisions of the Commission that impact revenue requirement as a result of this rate application, as well as any change in the implementation date of customer rates.

Furthermore, we noted that another jurisdiction in Atlantic Canada uses a revenue shortfall deferral when there is a delay in the implementation date of customer rates. Newfoundland and Labrador Hydro and Newfoundland Power Inc. both have used excess earnings or revenue short fall accounts in the past to address balances which accumulate due to rate implementation dates that differ from the forecast. We also compared MECL's methodology to Newfoundland Power's revenue shortfall deferral account approved in its 2014, 2016/2017 and 2019/2020 general rate applications in Order No. P.U. 13 (2013), Order No. P.U. 25 (2016) and Order No. P.U. 2 (2019) and noted a similar approach.

During our review of this methodology we asked MECL to illustrate the impact on revenue requirement for 2020 and 2021. In MECL's response they quantified the impact of amortizing the shortfall over an 18-month period. The original analysis appeared to overstate revenue requirement as it was only capturing the amortization expense but not the original set up of the revenue shortfall deferral account. However, MECL has provided additional evidence which reflects the offsetting adjustment through miscellaneous revenue.

4.4. Conclusion

Based on our results of the above procedures, nothing has come to our attention that the proposed revenue shortfall of $1,525,240 to be deferred and recovered over the rate setting period appears unreasonable. We did not note any discrepancies in the calculation of the proposed revenue shortfall and the components of the revenue shortfall are internally consistent with the Company's January 2020 filing (Amended II) and updated information. Additionally, the Company's methodology to recover revenue shortfall does not appear unreasonable and is comparable to the methodology used by utilities in Newfoundland and Labrador. Given the circular nature of the revenue shortfall, we recommend that the final revenue shortfall is reviewed in the final determination of customer rates.

5. CTGS decommissioning

5.1. Background

In accordance with section 10 of the Electric Power Act (“the Act), the Company requires approval to sell, assign, transfer, lease, mortgage or otherwise dispose of its property outside the ordinary course of business. As stated within Order UE19-08, MECL asked for the Commission’s approval to decommission the Charlottetown Thermal Generating Station (“CTGS”) beginning in 2019. In the November 2018 GRA, MECL stated that they required an estimated $14.5 million from ratepayers, to be recovered from the cost of decommissioning and is also seeking to recover the amount of the accumulated reserve variance for CTGS, estimated to be $16.245 million. MECL hired GHD Ltd. (“GHD”) to develop a decommissioning plan, submitted June 28, 2018, and provided MECL with support to develop CTGS decommissioning timelines. In MECL’s November 30, 2018 GRA, they specifically proposed the following:

1. The Commission grant approval, under Section 10 of the EPA, of the decommissioning plan, including the estimated $10.43 million (2018 dollars) net decommissioning cost, the projected timelines and the CT3 Balance of Plant Equipment Building Capital expenditures;
2. The Company be directed to submit, in its 2020 Capital Budget Application, the final project details and budget for the CT3 Balance of Plant Equipment Building (“BOP”);
3. The Company be directed to take the steps necessary to affect the CTGS decommissioning, including public consultation, environmental and regulatory approvals; and
4. The Company be directed to monitor the cost estimates and report updates on costs and project timelines every six months with the first report due August 31, 2019 for the period ending June 30, 2019.

The delay in approving MECL’s November 30, 2018 GRA affected MECL’s proposed timelines. The Commission subsequently hired Synapse Energy Economics Inc. (“Synapse”) to review GHD’s decommissioning study, and, as stated in UE19-08, recommended the following:

1. The Commission should approve the retirement of Turbines 7–10 at CTGS;
2. The Commission should not approve the demolition of the non-BOP portion of the CTGS structure until MECL presents a more robust case for the cost-effectiveness of demolition over retention;
3. The Commission should not approve demolition of the BOP-portion of the CTGS and construction of a new BOP building unless MECL can present a clearer justification, since demolition does not appear to be meaningfully less expensive than maintaining the BOP section of the CTGS;
4. The Commission should deem the entire CTGS site used and useful. However, this designation should be made contingent on MECL filing a long-term plan for energy system utilization for the site in short order;
5. The Commission should institute appropriate safeguards to ensure that MECL continues to minimize costs as the decommissioning process proceeds; as currently construed, there is no incentive for the utility to keep costs below the approved budget for the decommissioning;
6. MECL should be required to make a clearer case for the magnitude of the mobilization- demobilization budget item, substantiating why it believes that it will be necessary to hire a contractor from outside the province;
7. The Commission should ensure that MECL conducts all necessary environmental testing and other necessary follow-up on risk items before commencing the decommissioning, and that it modifies its projected decommissioning budget and workplan as appropriate based on the results of subsequent testing;
8. Synapse recommends that MECL conduct a simple probabilistic analysis in which the probability of occurrence for each environmental risk item is multiplied by the total cost for each associated risk item in order to produce a more accurate assessment of total environmental risk exposure for the decommissioning;
9. If any revisions are made to the proposed workplan and budget, then MECL should be instructed to submit a new budget that not only reflects the modifications to the site decommissioning cost, but also adjusts the value of any other items that are assessed in proportion to the site decommissioning cost, including allowances;

10. The requested increase in depreciation rates should only be granted if MECL can clearly illustrate how the lag in implementation of the previous rate change, adjusted service life assumptions, shift in net salvage, and other factors have contributed to the requested revision to the current rates; and
11. Decommissioning costs should not be escalated unless MECL can provide a clear justification for escalation and illustrate that this escalation is consistent with the approach taken in past CTGS-related financial calculations.
12. Synapse has determined that recommendations 1, 6 and 9 (as mentioned above) are resolved. In order UE 19-08 the demolition of the existing Steam Plant Building and the construction of a new balance of plant was not approved by the Commission. MECL was also ordered to abide by specific protocol put in place by the Commission and file reports based on the Commissions Orders. Those are further explained in our findings and observations.

Synapse has determined that recommendations 1, 6 and 9 (as mentioned above) are resolved. In order UE 19-08 the demolition of the existing Steam Plant Building and the construction of a new balance of plant was not approved by the Commission. MECL was also ordered to abide by specific protocol put in place by the Commission and file reports based on the Commissions Orders. Those are further explained in our findings and observations.

5.2. Procedures

The following procedures were completed during our work for the CTGS decommissioning review:

1. Reviewed the reasonableness and methodology of the decommissioning approach put in place by MECL;
2. Checked the clerical accuracy of MECL's decommissioning rates and methodology as ordered in UE 16-04 and UE19-08;
3. Confirmed that MECL has filled all appropriate documentation requested in UE 19-08 either before, during, or after the decommissioning project, as ordered in UE 19-08; and,
4. Reperformed decommissioning cost calculations as filed in Appendix 8 CTGS Variance Deferral.

5.3. Findings and observations

MECL's reasonableness and methodology of their decommissioning approach follows the Company's accounting policies and practice as well as the recommended approach as described in the Gannett Fleming 2017 Depreciation Study. MECL's accounting policies for additions and retirements of an asset are different than those calculated in the 2017 Depreciation Study, but all other methodology is followed. MECL's accounting policies and practice is to record one half year depreciation in the year of addition and one-half year depreciation in the year of retirement. This is based on their assumption that assets are generally acquired and disposed of throughout the year as opposed to at the beginning or end. The 2017 Depreciation Study assumes one full year of depreciation. As a result, MECL estimates may be lower than otherwise required to recover all original and estimated net removal costs for the CTGS. MECL also believes that the lower estimates relate to the delay in MECL adopting higher deprecation rates, as follows:

1. UE16-04 orders MECL to incorporate depreciation rates based on a study completed in 2014. These depreciation rates were to remain in effect until varied by the Commission;
2. UE16-04 orders MECL to conduct an updated depreciation rates study to be submitted on or before June 30, 2018;
3. UE19-08 orders MECL to adopt all the recommendations made in the 2017 Depreciation Study by Gannett Fleming, effective January 1, 2020;
4. UE19-08 does not approve the proposed demolition of the existing Steam Plan Building at the CTGS, and does not approve the proposed construction of a new balance of plan as outlined in GHD's decommissioning plan; and
5. UE19-08 does approve all other aspects of GHD's decommissioning plan.

MECL provided an estimate of the costs that will need to be collected from ratepayers at the time of decommissioning in 2022. This cost is outlined in “Appendix 8 CTGS Variance Deferral” and is calculated to be an estimated $9,654,524 for December 31, 2021, which includes a decommissioning cost estimate of $9,724,000 at December 31, 2020.

In UE19-08, MECL was ordered to file various studies and reports relating to the decommissioning of the CTGS site to the Commission on or before September 30, 2020. Those reports are as follows:

- Long-term plan for energy system utilization at the CTGS site; in the interim, the CTGS site will be deemed used and useful and the Commission will re-evaluate that classification based on the receipt and review of MECL’s long-term plan;
- A detailed study of the Island transmission system to determine its capabilities under high import situations;
- The use of transmission, generation and peak load management techniques in order to accommodate the growing peak load and potential high imports; and
- Whether additional on-Island generation is the optimal solution.

Once MECL begins decommissioning, they are required to submit written reports every six months from the date of commencement the decommissioning; if the cost varies by plus or minus $500,000 MECL shall be required to apply to the Commission for approval of the variance.

In the Amended Rate Application submitted January 31, 2020, MECL outlined the following recommendations related to the CTGS. Our comments regarding MECL’s recommendations are also included:

MECL recommendation	Our Comments:
The Commission approve the establishment of a regulatory deferral account, as of January 1, 2020, for the projected unrecovered depreciation and reserve variance amortization associated with the two-year gap in implementation of the Gannett Fleming 2017 Depreciation Study rates and the retirement year assumption differences.	MECL’s concern is that due to the lower depreciation rates applied to the CTGS site, as well as the additions and retirement assumptions, there may be a significant rate increase to ratepayers of the unrecovered depreciation and variance when the assets are retired. The proposed amount of the shortfall is the total capital cost of the CTGS (including the estimated decommissioning costs, net of salvage) less the total estimated amount that will be recovered from customers through depreciation charges up to when the asset is retired in 2021. These amounts are set out in Appendix 8 of the Application for an estimated amount of $9,654,524 at December 31, 2021. MECL’s proposed solution is to create a new deferral account effective January 1, 2020 in order to reduce a rate increase to ratepayers, instead of recovering the estimated CTGS variance over 2020 and 2021 in customer rates. If approved by the Commission, the Company has noted that the extent that any actual amounts differ (additional capital costs, decommissioning costs, salvage variances and/or depreciation charges recovered) from the amounts set out in Appendix 8, these amounts will be reflected in the balance in the deferral account and any over/under collection will be recovered from or refunded to customers in a manner as determined by the Commission once the amounts are known. Under the normal course of accounting treatment once the CTGS is deemed to be retired and thus no longer used and useful it would be expensed – as a loss on disposal unless a regulatory deferral account is approved by the Commission. With a regulatory deferral account the recovery of the estimated $9,654,524 would be amortized over a period approved by the Commission as a component of revenue requirement, typically over a rate setting period such as 2022 and 2023 as recommended by MECL in this application. We have confirmed with MECL that balance of the decommissioning costs has not been included in the rate base in actual 2019 results as the approval has not been

MECL recommendation	Our Comments:
	provided by the Commission. When we asked what impact the CTGS has on the revenue requirement and customer rates for 2020 and 2021, MECL provided the following responses: *"The proposed regulatory deferral account as of January 1, 2020 for the projected unrecovered depreciation and reserve amortization has not been included in the 2019 rate base calculation provided with this response.* [Furthermore], *with respect to the proposed regulatory deferral account for the CTGS balance, no amounts have been included in revenue requirement or rates for 2020 and 2021."* We further understand that the CTGS regulatory asset of $9,654,524 included in proposed rate base in 2020 and 2021 is fully offset by the same amount in accumulated depreciation, and therefore it has a $Nil increase in rate base in 2020 and 2021. We asked MECL if the regulatory asset is not approved by the Commission what impact it would have on revenue requirement for 2020 and 2021. MECL stated that the depreciation shortfall will need to be collected and the expense added to the revenue requirement. The following is MECL provided response to the impact on the revenue requirement: *"Assuming the additional depreciation is collected equally over the two year period ($4,827,250 per year), revenue requirement would increase by this amount each year less interest costs for a total of $4,773,600 in 2020 and $4,643,600 in 2021."* MECL provided the following response when asked to calculate the impact on customer rates: *"A typical customer would see their annual cost increase from the proposed 1.1% in 2020 and 1.2% in 2021 to 3.6% in 2020 and 0.6% in 2021."* We acknowledge that without further direction from the Commission MECL will have an undepreciated CTGS asset and decommissioning costs that it has not had an opportunity to recovery from customers. We also recognize that when CTGS is approaching its retirement that MECL will have an unresolved regulatory accounting matter. However, we question the necessity of creating this deferral account at January 1, 2020 given the ongoing review by IRAC for the decommissioning of the CTGS. This deferral is based on the projected variance between the unrecovered depreciation due to the delay of the implementation of depreciation rates and an estimated decommissioning cost of $9,724,000 at December 31, 2020. As such, we recommend that the Commission consider denying MECL's request for the deferral amount and take up as a matter later, after the technical update and new depreciation study are completed.
The Company obtain a technical update to the 2017 Depreciation Study by Gannett Fleming as at December 31, 2019 to provide an estimate of the amount to be recorded in the deferral account	The Company obtaining a technical update to the 2017 Depreciation Study by Gannett Fleming as at December 31, 2019 to provide an estimate of the amount to be recorded in the deferral account is reasonable.
The new depreciation study to be done based on financial results up to December 31, 2020, as directed in Order UE19-08, shall include any updates to the	The new depreciation study to be done by MECL based on financial results up to December 31, 2020 which will updates to the amounts in the deferral account for consideration of the Commission is reasonable.

MECL recommendation	Our Comments:
amounts in the deferral account for consideration of the Commission.	
The target amortization period for the deferral account be 2022 and 2023.	We recommend that the target amortization period for the deferral account be 2022 and 2023 is addressed by the Commission as part of the next GRA.

5.4. Conclusion

Based on our procedures above we recalculated MECL's CTGS Variance Deferral at the end of 2021 of $9,654,524 as presented in Appendix 8 and did not note any exceptions.

We recommend that the Commission consider denying MECL's request for the deferral amount at the present time. We recommend that MECL considers filing a future application for this deferral after the technical update and new depreciation study are completed and there is less uncertainty regarding the balance that is being deferred.

6. Average rate base and return on rate base

6.1. Background

The Company's calculations of its forecast average rate base for the years ending December 31, 2020 and 2021 were provided during our work. The Electric Power Act ("EPA") defines rate base as *"the maximum valuation of assets fixed by the Commission which a public utility may earn a percentage of return established by the Commission, or another method of computing a maximum return as determined by the Commission."*

6.2. Procedures

The following procedures with respect to verifying the calculation of average rate base were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- Agreed all carry-forward data to supporting documentation including prior years audited financial statements and internal accounting records, where applicable;
- Agreed forecast data to supporting documentation to ensure it is internally consistent with the application and other areas of the forecast;
- Checked the clerical accuracy of the continuity of the rate base for 2019 actuals and forecasted results for 2020 and 2021;
- Recalculated the forecast rate base and return on rate base for 2020 and 2021; and,
- Agreed the methodology used in the calculation of the average rate base to the Electric Power Act and relevant Orders to ensure it is in accordance with established policy and procedure.

5.2.1 Average rate base

The following table provides the 2018 to 2019 actual average rates base and the Company's forecast average rate base for 2020 and 2021:

Calculation of Average Rate Base				
Components	**2018A**	**2019A**	**2020F**	**2021F**
Fixed Assets	$ 654,053,538	$ 679,767,856	$ 712,215,800	$ 693,668,900
Less: Capital Work in Progress	(1,688,342)	(3,750,888)	-	-
Less: Accumulated Amortization	(236,162,822)	(245,078,293)	(269,903,600)	(231,933,900)
Less: Contributions in Aid of Construction (net of amortization)	(24,185,307)	(23,691,857)	(24,598,000)	(25,496,000)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(7,496,013)	(13,522,753)	(19,754,200)	(26,214,600)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	3,976,693	2,772,690	72,200	(478,100)
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(290,982)	(1,057,328)	-	-
Add: Deferred Financing Costs	859,810	961,283	947,500	933,000
Add: Intangible Assets	3,915,322	4,002,494	4,150,000	4,300,000
Add: Deferred Demand Side Management Costs	156,998	127,446	166,600	-
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,586,343	1,492,744	1,399,400	1,305,900
Add: Regulatory Asset - Storm Deferral	-	3,002,882	-	-
Less: Employee Future Benefits Liability	(7,837,014)	(7,631,568)	(7,711,700)	(7,961,700)
Less (Add): Regulatory Liability OPEB	1,168,904	2,536,000	2,986,600	2,813,800
Less: Regulatory Liability - Rebates Payable to Customers	(15,725,025)	(15,453,528)	(5,847,300)	(4,648,100)
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	9,654,500	9,654,500
Plus: Working Capital Allowance Comprised of:				
- Inventory	2,793,911	3,240,398	3,000,000	3,000,000
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,376,947	5,508,778	5,852,400	6,098,100
Income Taxes Paid X 3.6%	126,000	21,000	(21,000)	-
Total Rate Base	**$ 380,628,962**	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**
Average Rate Base	**$ 373,575,121**	**$ 386,938,159**	**$ 402,928,300**	**$ 418,825,500**

5.2.1 Return on rate base

The following table provides the 2018 to 2019 actual return on rate base and the Company's forecast rate of return on rate base for 2020 and 2021:

Calculation of Return on Rate Base				
	2018A	2019A	2020F	2021F
Total Revenue	$ 203,265,498	$ 210,720,773	$ 229,122,500	$ 231,002,500
Less: Operating Expenses (net of ECAM)	(147,386,371)	(153,485,663)	(162,897,200)	(169,336,300)
Less: Amortization of debt issue costs	(9,155)	(13,004)	(13,800)	(14,500)
	55,869,972	57,222,106	66,211,500	61,651,700
Less: Amortization Fixed Assets	(22,583,378)	(23,337,238)	(28,572,100)	(26,202,300)
Less: Amortization Deferred Charges	(617,450)	(250,598)	(3,223,700)	(260,000)
	(23,200,828)	(23,587,836)	(31,795,800)	(26,462,300)
Earnings Before Income Taxes and Financing Costs	32,669,144	33,634,270	34,415,700	35,189,400
Income Taxes	(6,266,588)	(6,483,242)	(6,742,200)	(6,978,200)
Earnings on Average Rate Base (financing costs excluded)	26,402,556	27,151,028	27,673,500	28,211,200
Rate Base - Year End Average	**$ 373,575,121**	**$ 386,938,159**	**$ 402,928,300**	**$ 418,825,500**
Actual/Requested Return on Average Rate Base (for rate making purposes)	**7.07%**	**7.02%**	**6.87%**	**6.74%**

6.3. Conclusion

Based upon the results of the above procedures we have concluded that:

- we did not note any discrepancies in the calculation of the average rate base, and therefore determined that the forecast average rate base is in accordance with established practice.
- we did not note any discrepancies in the Company's calculation of the return on average rate base, and therefore determined that the forecast return on average rate base has been calculated in accordance with established practice.

7. Return on average common equity (“ROE”)

7.1. Background

As per Order UE19-08, the Commission approved that MECL shall be entitled to earn a maximum return on average common equity of 9.35 percent based on 40 percent average common equity. Any over-earnings during the rate setting period shall be deposited to the RORA account for refund to ratepayers (with interest) in the manner set out in the Order UE19-08. The RORA will be discussed further in this report in a separate section.

7.2. Procedures

Our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

1. Agreed all carry-forward data to supporting documentation including audited financial statements and MECL’s internal accounting records, where applicable,
2. Agreed forecast data (regulated earnings, debt, equity; etc.) to supporting documentation to ensure it is internally consistent with filed evidence and other areas of the forecast,
3. Checked the clerical accuracy of the continuity of common equity, and,
4. Recalculated the forecast return on average common equity and Debt to Equity ratios as forecast for 2020 and 2021 to ensure it is in accordance with established practice.

7.3. Findings and observations

Below our findings are broken down into two sections: equity ratio and return on average common equity.

6.3.1 Equity Ratio

During our work we asked the Company to provide the supporting calculations on the average capital structure as provided in Appendix 2 for 2018 to 2021 and the equity ratio in Appendix 9, schedule 9-1 for 2016 to 2021, as provided in the January 2020 filing (Amended II). Based on MECL’s response, they noted an error within their Appendix 2 and provided a revised version “*to correct an error in how the financial statements filed in the original application treated the impact of the adjustments for non-recoverable Fortis Inc. costs on the equity balance and the cash flow. It should also be noted that in Schedule 9-1 – Average Capital Structure, the 2020 forecast amounts should be debt of 60.2% instead of 60.1% and equity of 38.8% instead of 38.7%. The amounts did not get updated from the original filing on January 31, 2020 to the correct amounts in the amended filing on February 14, 2020.*”

Regarding the error noted above, this was located within the Company’s balance sheet. Therefore, the error has no impact on revenue requirement and rates for this application.

Based on our recalculations of the components of the capital structure, the Company’s projected average capital structure and equity ratio for 2016 through 2021 is as follows:

Debt to Equity Ratios (%)						
	2016A	**2017A**	**2018A**	**2019A**	**2020F**	**2021F**
Total Debt	$199,849,362	$217,160,847	$ 228,060,193	$235,414,037	$240,408,340	$ 246,270,100
Total Equity	$138,342,099	$142,798,854	$ 147,475,128	$152,614,404	$158,743,540	$ 164,407,700
Total Debt + Equity	**$338,191,461**	**$359,959,701**	**$ 375,535,321**	**$388,028,441**	**$399,151,880**	**$ 410,677,800**
Debt (%)	**59.09%**	**60.33%**	**60.73%**	**60.67%**	**60.23%**	**59.97%**
Equity (%)	**40.91%**	**39.67%**	**39.27%**	**39.33%**	**39.77%**	**40.03%**

As seen in the table above the Company’s forecast average common equity for 2020 is below the 40% maximum approved by IRAC, while the 2021 forecast is slightly above the threshold.

6.3.2 Return on Average Common Equity

Based on our recalculations, the tables below present MECL's Regulated Earnings, Average Common Equity, and the resulting Return on Average Common Equity based on these two components. These tables present the 2018 actuals to 2021 forecasts from the January 2020 filing (Amended II):

Average Common Equity ($)				
	2018A	2019A	2020F	2021F
Current Year Equity (Forecasted or Actual)	$149,937,329	$155,291,479	$162,195,600	$166,619,800
Prior Year Equity (Forecasted or Actual)	145,012,926	149,937,329	155,291,479	162,195,600
Average Common Equity	**$147,475,128**	**$152,614,404**	**$158,743,540**	**$164,407,700**

Equity excludes non regulated equity.

Return on Average Common Equity (%)				
	2018A	2019A	2020F	2021F
Regulated Earnings	$ 13,792,864	$ 14,262,630	$ 14,843,000	$ 15,371,600
Average Common Equity	$ 147,475,128	$ 152,614,404	$ 158,743,540	$ 164,407,700
Return on Average Common Equity (%)	**9.35%**	**9.35%**	**9.35%**	**9.35%**

As shown in the table above the Company's forecast Return on Average Common Equity for 2020 and 2021 is 9.35% as directed by IRAC in Order UE 19-08 and any over-earnings were additions to the RORA account during 2018 to 2020.

6.3.3 Over earnings

MECL has consistently over earned each year since its last GRA resulting in significant balances transferred to the RORA. When MECL's revenue requirement for rate setting purposes is greater than actual for a given year, the Company is able to achieve the maximum ROE allowable, i.e. the company has collected too much revenue from rates to cover its costs and return on investment When MECL's forecast of revenue requirement for rating setting purposes is less than actual for a given year, the Company bears the risk of not reaching the maximum ROE in a given year, i.e. company has not collected enough revenue from rates to cover its costs and return on investment, and as a result earns less than its allowable ROE.

As a result, MECL has an inherent bias to overstate its revenue requirement for rate setting so that it can earn its maximum ROE.

6.3.4 Return on Rate Base and Cost of Service Regulation

MECL maximum allowable rate of return has been based on average common equity as discussed above. The *Electric Power Act* states that MECL is entitled to earn a just and reasonable return on rate base. Under a cost of service regulation, a company would normally use either the Invested Capital method or the Asset Rate Base Methodology (ARBM) to calculate the allowed return on rate base. Both methods are regulatory accounting methodologies to convert cost of capital to return on rate base. With an ARBM, a utility's allowed return is calculated as its rate base multiplied by its weighted average cost of capital (WACC or allowed rate of return) and is simplistic in this sense. The Invested Capital method represents the mathematical relationship between the weighted average cost of capital; average invested capital; and the average rate base for a given forecast year. In theory, the Invested Capital method and the ARBM should produce the same fair returns because the rate base should represent the invested capital necessary to finance the rate base.

MECL current rate application filings do not include the Company's weighted average cost of capital; average invested capital; the average rate base or the return on rate base, therefore it lacked clarity about its return on investment. We requested this information from MECL during our review and noted that the average return on rate base was reconciled to the company's WACC by the ratio of invested capital over average rate base; this is consistent with the Invested Capital Method as described above.

The results of our review of MECL's response to the average rate base and return on rate base is outlined in section 6 of our report.

We recommend that MECL file schedules in their next GRA that include the Company's weighted average cost of capital, average invested capital, average rate base, and return on rate base, in addition to their current schedules related to return on average common equity.

7.4. Conclusion

The proposed average capital structure for 2020 and 2021 is consistent with the position approved by IRAC in Order UE 19-08. The above calculations of Equity ratios are consistent with Appendix 9, Schedule 9-1 presented in the January 2020 filing (Amended II).

Based on the results of the above procedures, we did not note any discrepancies in the calculation of the forecast rate of return on average common equity for 2020 and 2021 and is consistent with the average common equity of 9.35% approved by IRAC in Order UE 19-08. The above calculations of return on average common equity are consistent with Appendix 2 presented in the January 2020 filing (Amended II).

8. Provincial costs recoverable

8.1. Background

MECL's original general rate application filed on November 30, 2018 included a discussion of two provincial cost recoverable amounts for:

1. PEI Energy Accord, and
2. 2018-2021 PEI Energy Corporation ("PEIEC") Electricity Efficiency and Conservation Plan ("EE&C Plan").

MECL's updated financial information as filed with the Commission on January 31, 2020 and subsequently amended includes an approach for dealing with these items. Specifically, the Provincial Costs recoverable includes the recovery of balances from rate payers as a result of the PEI Energy Accord and a balance to be remitted to the PEIEC related to the Electricity Efficiency and Conservation Plan.

7.1.1 PEI Energy Accord Funding

The PEI Energy Accord amount relates to the recovery of associated payments established in 2011. This balance relates to the recovery of financing costs associated with the Pt. Lepreau and Dalhousie project costs where Government used their preferred financing rates to underwrite the financing for these projects to mitigate the impact on rate payers at the time and into the future. MECL's proposed rate rider associated with the PEI Accord Funding is calculated as follows:

	2019A	2020F	2021F
Sales (kWh) **(Note 1)**	1,285,010,891	1,354,147,389	1,391,438,164
PEI Accord Funding	$ 6,887,658	$ 5,739,900	$ 5,717,652
Collection Rate ($/kWh)	$ 0.00536	$ 0.00424	$ 0.00411

Note 1 – *Agrees to MECL's load forecast for the period from March 1, 2020 to February 28, 2022. Therefore, there is a difference between what is presented here and the figures in the energy supply forecast section of the report. Energy supply forecasting by MECL is presented on a calendar year.*

In GT-RFI-2019-62 we asked MECL to provide support for the payment requirements associated with the Pt. Lepreau and Dalhousie project debt. In response to this request they directed us to Commission General Rate Application Interrogatory 2 b. We compared the balances included in the January 31, 2020 GRA (Amended II) to this response and found the following:

	2019A	2020F	2021F
PEI Accord Funding	$ 6,887,658	$ 5,739,900	$ 5,717,652
Annual Payment Schedule **(Note 2)**	5,739,851	5,739,851	5,717,647
Difference	**$ 1,147,807**	**$ 49**	**$ 5**

Note 2 – *Per Commission General Rate Application Interrogatory 2 b*

PEI Accord Funding is collected from MECL's customers on a per kWh basis and therefore the amount collected in any given year is subject to sales fluctuations experienced in that year. We discussed this variance with MECL and noted that because sales were greater than forecasted in 2019, they collected more than was required to service these debt arrangements. However, MECL has indicated that they remit the total amount collected to PEI Energy Corporation regardless of it is was more or less than what was expected. Therefore, the overcollection in 2019 is within PEI Energy Corporations prevue to address the appropriate treatment of these funds.

Furthermore, we understand that MECL has previously asked to revise the method of collecting this balance from a rate rider approach to including it in base rates as a component of revenue requirement. In the November 30, 2018 GRA filing MECL requested to *"…effective March 1, 2019, it is proposed that the amount owing my Maritime Electric customers to the Province be recovered as an energy-related cost through ECAM…".* However, in UE19-08 the Commission decisions *state "…The Commission does not approve the recovery of Provincial Costs Recoverable through the Energy Cost Adjustment. the Provincial Costs Recoverable shall continue to be collected through a rate rider in basic rates…"*. The Commission may want to consider the approach to collecting his balance in future years to eliminate the over or under collections. Alternatively, the Commission could also consider providing MECL with guidance regarding how the annual over collection or short fall should be addressed.

7.1.2 2018-2021 PEI Energy Corporation Electricity Efficiency and Conservation Plan

As noted in section 3 of this report, MECL collects and remits funds to PEI Energy Corporation related to provincial demand side management initiatives. This matter has evolved since the 2016 GRA therefore the following section of our report provides some background information on MECL's various applications and the Commissions decisions.

7.1.2.1 Results of the 2015 review of demand side management

In 2015 MECL submitted a DSM Application to the Commission for their consideration. In Order UE15-02 the Commission ordered *"…the public outreach and education component of the Plan, with an annual cost of $167,000 to be recovered through customer rates as a component of the Energy Cost Adjustment Mechanism, is hereby approved. The Commission does not approve the other components of the Plan. The Commission will issue and order in due course requiring the Company to file a new Energy Efficiency and Demand Side Management Plan…"*

7.1.2.2 2016 General Rate Application

During the 2016 GRA the Commission considered MECL's requests regarding DSM and ultimately Order UE16-04R which indicated that *"…on November 3, 2015, the Commission issued Order UE15-02 with respect to the DSM Application. The Commission refused to accept the majority of the DSM plan as filed by Maritime Electric, approving only the public outreach and education components. The Commission has since engaged the services of expert consultants with respect to DSM and a report is forthcoming. The Commission expects that Maritime Electric and the Government will work together to develop a DSM plan that is consistent with, and complimentary to, the Provincial Energy Strategy that is currently being developed by the Government….". Furthermore, the Commissions decisions on this matter noted the following "…the Commission does not approve the recovery of Provincial Costs Recoverable through the Energy Cost Adjustment Mechanism ("ECAM"), and does not approve the corresponding re-basing of the ECAM base rate to include the Provincial Costs. The Provincial Costs Recoverable shall continue to be Collected through a rate rider in basic rates…"*

7.1.2.3 PEI Energy Corporation - 2018-2021 Demand Side Management Resource Plan

On June 29, 2018, the PEIEC submitted an application to the Commission seeking approval of an electricity efficiency and conservation plan (the "PEIEC's EE&C Plan" or the "Plan") for a three-year term from 2018 to 2021. The Commission approved this plan in Order UE19-03 on May 17, 2019 for the period ending March 31, 2021.

Costs associated with the Plan were to be recoverable from electricity customers based on the percentage of sales of electricity in the province. At the time of the application Summerside Electric would contribute approximately 10 percent of the total recoverable Plan costs, and Maritime Electric would contribute approximately 90 percent. The costs to be recovered from Summerside Electric and MECL on a prorate basis have been outlined in the table below:

	2018/2019	2019/2020	2020/2021
MECL Funding Summerside Funding	$ 600,000	$ 970,000	$ 1,200,000
MECL % Allocation	90%	90%	90%
MECL Portion (rounded)	$ 540,000	$ 873,000	$ 1,080,000

The Order provides the following guidance with regards to the treatment of the costs associated with the PEIEC EE&C Plan:

- *“The funding to be provided by Maritime Electric and Summerside Electric shall be shared proportionately between the utilities based on the percentage of sales of electricity in the Province.”*
- *“In the event that Summerside Electric fails or refuses to pay its proportionate share of the funding in any given year, its share shall not be collected or collectable from Maritime Electric or its ratepayers.”*
- *“Maritime Electric shall be required to recover its proportionate share of the funding from its ratepayers and shall remit this amount to PEIEC/efficiencyPEI on a monthly basis.”*
- *“PEIEC shall establish the appropriate rate rider for each of Maritime Electric's rate classes, which rate riders shall be set for the term of the Plan.”*
- *“The rate rider shall be incorporated into Maritime Electric's rates for electrical service and shall not be identified as a separate line item on customers' bills.”*
- *“The costs of the EE&C Plan shall be treated as an expense as incurred rather than amortized over the life of the EE&C measures.”*

7.1.2.4 November 2018 GRA Filing

When MECL filed the November 2018 GRA the PEIEC had filed their Demand Side Management Resource Plan with the Commission but the final findings and orders were not yet known. As a result, MECL incorporated the PEIEC requests into the GRA as if the funding requested and the rate rider structure proposed had been approved.

In Order UE19-08 the Commission describes their findings with regards to the Provincial Costs Recoverable balances presented in the November 2018 GRA as follows:

- *“The Commission is not prepared to allow the recovery of Provincial Costs Recoverable through the ECAM and is not prepared to allow the corresponding re-basing of the ECAM base rate to include the Provincial Costs Recoverable. Instead, the Provincial Costs Recoverable shall continue to be collected through a rate rider in basic rates. MECL confirmed that this will have no impact on the proposed rates.”*

- *“In support of this finding, the Commission notes that the Provincial Costs Recoverable are a known and fixed amount to be recovered from ratepayers. As the amount recoverable is not subject to fluctuate, it can properly be collected through basic rates. The Commission is therefore satisfied that the Provincial Costs Recoverable should continue to be collected through a rate rider in basic rates. MECL did not provide any compelling evidence as to why this practice should change.”*

Further the Commission thereby ordered:

- *"The rates, tolls and charges for electric service currently in effect for the period from March 1, 2018 to February 28, 2019, shall remain in effect until February 28, 2020, or until otherwise varied by the Commission."*
- *"The rates, tolls and charges for electric service effective March 1, 2020 and March 1, 2021 shall be determined upon the Company filing updated financial information as at December 31, 2019…" and*
- *"The Commission does not approve the recovery of Provincial Costs Recoverable through the Energy Costs Adjustment Mechanism ("ECAM") and does not approve the corresponding re-basing of the ECAM base rate to include the Provincial Costs Recoverable. The Provincial Costs Recoverable shall continue to be collected through a rate rider in basic rates."*

7.1.2.4 January 31, 2020 (Amended II) Filing

In MECL's current filing (January 31, 2020 (Amended II)) it indicates *"Order UE19-03 sets out the annual funding requirements for the PEIEC EE&C Plan and directs that the amounts shall be recovered from customers through a rate rider to be incorporated into the Company's electricity rates. Commission Order UE19-08 directed that there be no change to electricity rates in 2019. As a result, the Year 2 (2019/2020) funding to be recovered from Maritime Electric customers as a rate rider on each customer class was not included in the approved rates…"*

To extend the PEIEC EE&C Plan period to match the full rate setting period of this application MECL has assumed that the costs forecasted for the 2020/2021 period of the Plan will remain in effect for 2021/2022 as follows:

	2018/2019	2019/2020	2020/2021	2021/2022
MECL Funding Summerside Funding	$ 600,000	$ 1,570,000	$ 1,200,000	$ 1,200,000
MECL % Allocation	90%	90%	90%	90%
MECL Portion (rounded)	$ 540,000	$ 1,413,000	$ 1,080,000	$ 1,080,000

Note 1 – We understand that the $540,000 noted for 2018/2019 was collected by MECL and remitted to PEI Energy Corporation based on discussion with Commission Counsel. As this period is outside of the scope of the current GRA proceeding we have not vouched this to underlying evidence such as proof of payment or invoices.

Given that MECL's position is that they did not collect this balance in 2019/2020 the proposed impact on rates in this application is as follows:

	2020/2021	2021/2022
MECL Portion Current Year	$ 1,080,000	$ 1,080,000
MECL Portion Uncollected Prior Year	873,000	-
MECL Portion (rounded)	$ 1,953,000	$ 1,080,000
Forecasted sales (kWh)	1,354,147,000	1,391,438,000
Proposed rate rider ($/kWh)	0.0014	0.0008

MECL's comment that funding to be recovered from Maritime Electric customers as a rate rider on each customer class was not included in the approved rates differs from Grant Thornton's interpretation of the Commission's Order. Therefore, in request GT-RFI-2019-63 we attempted to clarify MECL's interpretation:

- *We understand that your position is that no amounts were collected for the PEIEC EE&C plan in 2019/2020. However, did base rates from 2018/2019 include an amount to recover MECL's 90% portion of the $600,000 funding requirement outlined on page 19 of UE19-03? If so, what was the collection rate per kWh? Please provide a calculation of the total amount collected in 2019/2020 if the collection rate from 2018/2019 was applied to 2019/2020 energy sales. Once you have calculated the balance please quantify the difference between the amount collected and the funding requirements noted on page 9 of the amended application filed on February 14, 2020. Finally, please comment on any knock-on effects this adjustment would have on other areas of the application.*

MECL provided a detailed response to this request which outlined the background of the matter from the 2016 GRA forward, their various steps from that point to the current application as well as calculations of the potential impact of their interpretation and our interpretation for the Commission's consideration. The following is an excerpt from their response:

- *"…the approved DSM funding in the Company's revenue requirement for 2018 was $573,000, which is comprised of $167,500 for the Company's COP* [Community Outreach Program] *and the balance, $405,500, considered the component of revenue requirement in 2018 to provide funding for the Provincial DSM programming in 2018/19. At the time of filing the Company's General Rate Application on November 30, 2018, IRAC was considering the PEI Energy Corporation's (PEIEC) EE&C Plan, filed on June 29, 2018. The EE&C Plan proposed that the recovery of the DSM funding from the Company's customers be implemented as a rate rider on customer rates and that there be a true-up by rate class at the reset of the EE&C rate rider. Maritime Electric prepared its General Rate Application evidence on funding the EE&C Plan to align with the proposals contained in the PEIEC's filing…"*
- *"…The forecast for 2019 Amortization – DSM Costs includes only the recovery of the Company's COP program amortization as approved by Commission Order UE15-02* [$167,500]. *The Application also proposed that the cost of the 2019/2020 EE&C Plan of approximately $873,000* [MECL' s 90% share of the $970,000 approved in UE19-03] *be collected as a rate rider of $0.0007 per kWh and shown as a separate line item on customers' bills. On May 17, 2019, the Commission approved the PEIEC EE&C Plan in Order UE19-03. On page 16 of the Order, the Commission states that it: "accepts the proposal by PEIEC that it shall establish a rate rider for each of Maritime Electric's rate classes and that the rate riders shall be set for the term of the Plan." The Order also established the apportionment of costs to Maritime Electric customers for purposes of establishing the rate rider in paragraphs 3 and 4 (page 19). Further, paragraphs 7 and 8 direct the PEIEC to establish the rate rider for incorporation into the Company's rates, such that the rider would not be identified separately on the customer's bill. Although specific rate riders were not proposed for each customer rate class, the Company's General Rate Application evidence showing the exclusion of DSM costs from revenue requirement and proposing a rate rider for all rate classes as a rider on the basic rates aligns with the EE&C Plan and the Commission's Order.*
- *"…On September 27, 2019, the Commission issued Order UE19-08 with respect to the November 28, 2018 General Rate Application. At paragraph 4 of the Order, the Commission states that: "it is imperative that the Commission review each element of the revenue requirement to ensure that it is reasonable." Subsequent to performing its review of the Company's revenue requirement presented in Schedule 14-4 of the evidence, the Commission's Order only directed changes to the depreciation amounts included in revenue requirement when it did not approve the Company's proposals related to depreciation for 2019 but instead ordered the adoption of the Gannett Fleming depreciation study results effective January 1, 2020. All other forecast amounts comprising revenue requirement were unchanged and the Commission ordered that there be no change in electricity rates for 2019…"*
- *"…the revenue requirement for the Amortization of DSM costs in 2019 includes only the amortization of the Company's Community Outreach Program as approved in UE15-02 while the updated evidence also proposes that the 2019 and 2020 PEIEC EE&C Plan costs be collected as a rate rider effective March 1, 2020 rates in accordance with Commission Order UE19-03. It is the Company's view that it has properly presented the COP DSM costs as the only DSM costs in its revenue requirement for 2019 and future years and that the proposals presented to date regarding the rate rider for PEIEC EE&C costs properly reflect Commission Order UE19-03. As a result, the Company's basic rates, to recover its annual revenue requirement from customers, do not provide for funding the PEIEC EE&C program funding after 2018."*

7.1.2.5 Grant Thornton's Interpretation

We have assumed that the Commission's decision to maintain rates "…*currently in effect for the period from March 1, 2018 to February 28, 2019, shall remain in effect until February 28, 2020, or until otherwise varied by the Commission"* implies that the approved revenue requirement for 2019 was based on the 2018 revenue requirement which included a balance for DSM. Given that MECL's position on the matter and the resulting impact to ratepayers has been outlined in January 31, 2020 (Amended II) we have focused the following portion of our discussion on presenting the impact of our alternative interpretation of this matter.

The following table summarizes our interpretation of revenue requirement for 2019 based on the Commission's orders as outlined in UE19-08:

	2018F (Note 1)	2019F (Note 2)	2019A (Note 3)
Operating Expenses (Net of ECAM)*	$ 154,201,300	$ 154,201,300	$ 153,485,663
Interest Expense	12,644,900	12,644,900	12,901,422
Amortization – Fixed Assets	22,983,800	22,983,800	23,337,238
Amortization – DSM Costs	573,000	573,000	157,198
Amortization – Lepreau Writedown	93,400	93,400	93,400
Income Tax Expense	6,350,300	6,350,300	6,483,242
Return on Equity **	13,774,000	13,774,000	14,262,630
Total	**$ 210,620,700**	**$ 210,620,700**	**$ 210,720,793**

*Excluding Fortis Inc. Costs

**Before Disallowable Costs

Note 1 *- based on schedule 15-4 as presented in MECL's response to GT-RFI-2019-63*

Note 2 *- assuming UE19-08 implies that the 2018 approved revenue requirement was held unchanged for 2019*

Note 3 *- Per the January 31, 2020 (Amended II)*

If the approved revenue requirement for MECL in 2019 equals the forecasted revenue requirement for 2018 that was approved as part of the 2016 GRA it would imply that the following amount was collected by MECL as it pertains to the PEIEC EE&C Plan.

	Amount
Balance in revenue requirement	$ 573,000
Actual DSM expense in 2019	157,198
Difference	**$ 415,802**

As a result of this calculation we have revised MECL's calculated rate rider as follows:

	2020/2021	2021/2022
MECL Portion Current Year	$ 1,080,000	$ 1,080,000
MECL Portion Uncollected Prior Year **(Note 1)**	457,198	-
MECL Portion (rounded)	$ 1,537,198	$ 1,080,000
Forecasted sales (kWh)	1,354,147,000	1,391,438,000
Proposed rate rider ($/kWh)	0.0011	0.0008

Note 1 *- $873,000 less $415,802*

Procedures

Our procedures with respect to verifying the calculation of the provincial costs recoverable were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- Checked the clerical accuracy and continuity of the calculation of the provincial costs recoverable for 2019 actuals and forecast for 2020 and 2021;
- Reviewed the calculation of the provincial costs recoverable and rate riders for compliance with Commission Orders;
- Compared the funding requirements to underlying supporting documents for accuracy;
- Considered internal consistency between the proposed rate rider calculation and the energy sales forecast for the period;
- Reviewed responses from MECL regarding the above, and,
- Reviewed the recovery of DSM expenses for 2019/2020 and 2020/2021 in rates to be set effective 2020.

8.2. Findings and observations

Based on the procedures performed in this section of our report we have the following findings and observations:

- The PEI Accord recoverable amount is supported by the underlying debt amortization schedules. The rate rider calculation is mathematically correct and is based on MECL energy sales forecast. However, due to the structure of this cost recovery mechanism as a rate rider MECL has collected approximately $1.1 million more than the annual debt repayments associated with the Point Lepreau and the Dalhousie debt. We understand from discussion with MECL that the full amount including the overcollection is remitted to the PEIEC. However, the Commission should consider options for addressing the annual over or under collection based on actual kWh energy sales.

- The PEIEC EE&C Plan funding has been calculated by MECL in accordance with their interpretation of the Commission's Orders as outlined in UE19-08. However, the intent of this order is unclear as Grant Thornton has interpreted the language in the order differently than MECL. We have determined that MECL has collected approximately $416,000 in 2019 related to the PEIEC EE&C Plan. Our position is that this balance should be remitted to the PEIEC thereby reducing MECL's forecasted rate rider for the 2020/2021 collection period. However, MECL has noted that if this approach is adopted the impact to rate payers will be $nil as the balance will come out of the RORA account and therefore the reduction in the Provincial Energy Efficiency Program rate rider will be offset by an equal adjustment to the RORA rate rider.

9. Energy cost adjustment mechanism ("ECAM")

9.1. Background

The ECAM is a mechanism that is in place for MECL to recover/rebate energy costs above/below a base amount and to provide a smoothing effect regarding the collection or rebate of energy costs. It enables MECL to collect/return fluctuations in approved energy costs above/below the forecast base amount per kWh included in the basic rates. The most recent modification to the ECAM mechanism occurred in Order UE16-04 in 2016 when the Commission approved the ECAM as applied during the PEI Energy Accord.

Under the operation of the ECAM, MECL charges to expense, on a monthly basis, an amount equal to the net purchased and produced energy for the month ("NPP"), multiplied by a base rate per kWh. This amount is subtracted from the actual cost of energy purchased and/or produced during the month. The difference is then added to the Company's balance sheet for future recovery from, or return to, ratepayers over a period, as approved by the Commission.

Outlined in MECL's November 2018 GRA and in January 2020 filing (Amended II), MECL proposed no change in how the ECAM works.

With the adoption of the proposed ECAM Base Rates, MECL forecasted the balance of Costs Recoverable From (Payable To) Customers as of December 31 for the years 2020-2021. These forecasts were later updated in the July 2019 update and January 2020 filing (Amended II). The table below shows both the updated 2019 – 2021 forecasts/actuals of each for comparison:

Costs Recoverable From (Payable To) Customers ($)			
	2019F	2020F	2021F
Cost Recoverable From (Payable To) Customers – Per July Update	$ 2,063,346	$ 997,517	$ 207,290
	2019A	2020F	2021F
Cost Recoverable From (Payable To) Customers – Per January Update	$ 2,772,686	$ 72,203	$ (478,105)

In the July 2019 update and January 2020 filing (Amended II) MECL outlined forecasted monthly ECAM calculations for January 1, 2019 to December 31, 2021.

In Order UE19-08 the Commission outlines that it is not prepared to allow the recovery of Provincial Costs Recoverable through the ECAM and does not approve the corresponding re-basing of the ECAM base rate to include the Provincial Costs Recoverable. Instead, the Commission ordered that the Provincial Costs Recoverable shall continue to be collected through a rate rider in basic rates. Furthermore, the Commission ordered MECL to undertake a thorough review of the ECAM as it currently exists, including the expenses and accounts that are currently collected through the ECAM, and the practice of deferring a portion of the energy supply costs for collection from future ratepayers. This review is to be filed by MECL to the Commission on or before April 1, 2020.

9.2. Procedures

Our procedures with respect to verifying the calculation of the energy cost adjustment mechanism were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- Checked the clerical accuracy and continuity of the calculation of the energy cost adjustment mechanism for 2019 actuals and forecast for 2020 and 2021;
- Reviewed Appendix 3 for internal consistency (i.e. energy supply costs, net purchased and produced energy, energy sales forecast);
- Reviewed the calculation of the ECAM for compliance with Commission Orders; and,
- Performed analytical and trend analysis comparing historical actual energy costs to 2020 and 2021 forecast considering reasonableness, and accuracy and reliability of the forecast.

9.3. Findings and observations

The methodology used in the ECAM calculation as seen in Appendix 3 – Monthly ECAM Calculations, as provided by MECL in their January 2020 Update was consistent with methodology used in the November 2018 GRA and the July 2019 Update. ECAM is calculated in two parts:

1. Yearly ECAM Additions/(Deductions) – This is used to account for the energy costs adjustments in a given year; and
2. Rebates / Collections from ratepayers – This is determined through a rate rider (collection rate or ECAM Charge per kWh) determined by MECL in reference to costs recoverable from (payable to) customers in ECAM which is approved by Commission.

During our review of the ECAM methodology, we asked the Company to explain why the closing year balances for forecast 2020 and 2021 are not $nil. The following response was provided by MECL:

> *"The main reason the closing balances for ECAM in a given year is not zero is mainly to due to the timing between when the ECAM base rate and collection rates are calculated based on a December 31 calendar year and the reset date which is two months later on March 1 of the following year."*

Based on our recalculations, the table below presents a summary of components of the ECAM for 2019 actual, and 2020 and 2021 forecast:

Costs Recoverable From (Payable To) Customers ($)			
	2019A	2020F	2021F
Opening ECAM Balance	$ 3,976,694	$ 2,772,686	$ 72,203
Additions (Deductions)	(464,063)	(329,970)	56,364
Rebated (Collected)	(739,945)	(2,370,513)	(606,671)
Costs Recoverable From (Payable To) Customers	**$ 2,772,686**	**$ 72,203**	**$ (478,105)**

The above table is consistent with the Appendix 3, January 2020 filing (Amended II). Additionally, the additions (deductions) component above agrees with Appendix 9, Schedule 9-8 within the January 2020 filing (Amended II) for total operating expenses included in revenue requirement.

The ECAM is used to provide a smoothing effect to the collection or rebate of energy costs. The proposed ECAM base rate of $0.09225 per kWh and $0.09244 per kWh and collection rate of $0.0020 per kWh and $0.0001 per kWh for 2020 and 2021 forecast are used to calculate the Additions (Deductions) and Rebated (Collected) balance seen above, respectively. As a result, when ECAM is re-based these rates bring the costs recoverable from (payable to) customers to a near $nil balance with a 2020 and 2021 forecast closing balance of $72,203 and $(478,105), respectively.

The following is the summary of components of ECAM for forecast 2019 to 2021 as presented within the July 2019 Update:

Costs Recoverable From (Payable To) Customers ($)			
	2019F	2020F	2021F
Opening ECAM Balance	$ 3,976,694	$ 2,063,346	$ 997,517
Additions (Deductions)	822,825	1,979,257	417,335
Rebated (Collected)	(2,736,173)	(3,045,086)	(1,207,562)
Costs Recoverable From (Payable To) Customers	**$ 2,063,346**	**$ 997,517**	**$ 207,290**

Below we will discuss each component of the ECAM compared to the July 2019 Update.

8.3.1 Yearly ECAM Additions/(Deductions)

Yearly ECAM Additions/(Deductions) is calculated by deducting base energy costs, which is NPP multiplied by ECAM base rate, from total energy supply cost.

Based on our recalculations, the table below compares the July 2019 Update and January 2020 filing (Amended II) ECAM Additions/(Deductions) totals for 2019 to 2021:

ECAM Additions (Deductions)			
	Jan 2020 Update	July 2019 Update	Difference
Year	Actual/Forecast (A)	Forecast (B)	A-B
2019	(464,063)	822,826	(1,286,889)
2020	(329,970)	1,979,257	(2,309,227)
2021	56,364	417,335	(360,971)

As seen above, yearly ECAM Additions/(Deductions) have decreased from the July 2019 Update to the January 2020 filing (Amended II) in all three years. These differences are due to the following:

- Energy supply costs decreased approximately $17 million cumulatively from 2019 to 2021, which is due to the lower 2019 actual and updated lower 2020 and 2021 energy sales forecast within revenue requirement.

Energy Supply Costs ($)				
	Jan 2020 Update	July 2019 Update	Difference (C)	Percent Change
Year	Actual/Forecast (A)	Forecast (B)	A-B	C/B
2019	126,443,124	130,379,283	(3,936,159)	-3.02%
2020	133,276,383	140,684,316	(7,407,933)	-5.27%
2021	138,374,166	144,094,844	(5,720,678)	-3.97%

- Base energy costs decreased due to the lower 2019 actual NPP being approximately 17.6 million kWh less than forecast, in addition to the 2020 forecast decrease by approximately 16.3 million kWh between the two submissions.

Net Purchased and Produced Energy (kWh)				
	Jan 2020 Update	July 2019 Update	Difference (C)	Percent Change
Year	Actual/Forecast (A)	Forecast (B)	A-B	C/B
2019	1,385,298,410	1,402,929,515	(17,631,105)	-1.26%
2020	1,450,198,653	1,466,458,385	(16,259,732)	-1.11%
2021	1,496,869,680	1,496,833,146	36,534	0.00%

8.3.2 Rebated/(Collected) From Ratepayers

Amounts rebated/(collected) from ratepayers is determined by multiplying total energy sales (kWh) for a given month by the ECAM collection rate for that month.

The table below shows Rebated/(Collected) From Ratepayer totals as reported in the July 2019 Update and the January 2020 filing (Amended II):

Rebated (Collected) From Ratepayers ($)			
	Jan 2020 Update	July 2019 Update	Difference
Year	Actual/Forecast (A)	Forecast (B)	A-B
2019	(739,945)	(2,736,173)	1,996,228
2020	(2,370,513)	(3,045,086)	674,573
2021	(606,671)	(1,207,562)	600,891

As seen above the collection actual and forecast amounts from ratepayers decreased year over year from the July 2019 Update to the January 2020 filing due to an actual and forecasted energy sales decrease as explained above and a decrease in the collection rate each year due to the decreasing balance in the ECAM.

These collection rates from the January 2020 filing are included as rate riders within the final rates as presented within section 11.

9.4. Conclusion

Based on the results of the above procedures, nothing has come to our attention that the proposed ECAM base rate of $0.09225 per kWh and $0.09244 per kWh and ECAM charge rate of $0.0020 per kWh and $0.0001 per kWh for 2020 and 2021, respectively appear unreasonable. We did not note any discrepancies in the calculation of the forecast ECAM and components of the ECAM are internally consistent with the application's (i.e. energy supply costs, NPP) Appendix 3 presented in the January 2020 filing (Amended II) for the forecast years 2020 and 2021 and comply with Order UE 19-08. We can also verify that the Provincial Cost Recoverable is excluded from ECAM.

10. Weather normalization mechanism (“WNM”)

10.1. Background

The Weather Normalization Mechanism (“WNM”), also known as Weather Normalization Reserve (the “WNR” or the “Reserve”), is used to ensure that the Company earns its allowed rate of return during the year and operates by allowing MECL to reserve revenue earned in colder-than-average years for use in warmer-than-average years. When the Heating Degree Days (“HDD”) variation is above normal (colder temperature than historical average), the Company will experience incremental marginal net revenue (revenue less energy costs) which would be returned to customers by subtracting this amount from the Company’s income statement and adding it to the Reserve. When HDD variation is below normal (warmer temperature than historical average) there will be a shortfall in net revenue which will need to be recovered from customers by adding the marginal net revenue amount to the Company’s income statement and subtracted from the Reserve. Over a ten-year period, the Company anticipates that the variation from average HDD balances to zero as does the balance in the Reserve account.

In the Commission’s Order UE19-08, the Commission:

1. Extended the interim period of the WNR until February 28th, 2022 with no change in the methodology of the calculation of the WNM and Reserve account;
2. Requested MECL continue to file monthly balances of the WNR with the Commission as part of its monthly reporting; and
3. MECL file the year-end balance of the Weather Normalization Reserve account on or before January 31 in each of 2020, 2021, 2022.

MECL requested the Commission to approve WNR variables from January 1, 2019 to December 31, 2019 which were approved in Commission Order UE 19-10. The variables were approved as follows:

Approved Weather Notmalization Marginal New Revenue Variables	
Variable	Effective Date 1-Jan-19
Average HDD Value	4,365
MWh per HDD Coefficient	50.19
Forecast Unit Revenue per MWh	143.70
Forecast Unit Energy Cost per MWh	91.61

The Commission Order UE 19-10 further states MECL shall file the proposed 2020 WNR marginal net revenue variables with the commission on or before January 31, 2020. On January 31, 2020 MECL filed its proposed WNR variables. Subsequently, MECL provided updated 2020 WNR variables in Amended Applications filed February 10, 2020 and February 14, 2020. The proposed 2020 WNR variables in the January 2020 filing (Amended II) are as follows:

Proposed Weather Notmalization Marginal New Revenue Variables	
Variable	Effective Date 1-Jan-20
Average HDD Value	4,386
MWh per HDD Coefficient	68.07
Forecast Unit Revenue per MWh	145.29
Forecast Unit Energy Cost per MWh	92.25

10.2. Procedures

Our procedures with respect to verifying the updated components of the Weather Normalization Reserve and the annual adjustments were directed towards the verification of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- Reviewed the methodology used in calculating WNR balances for consistency with previous filings;
- Recalculated the WNR balances to confirm mathematical accuracy;
- Reviewed WNR account for compliance with Commission Orders UE19-08 and UE19-10;
- Reviewed WNR calculation to determine if discrepancies noted in Grant Thornton's December 2019 WNR Review Report were accurately incorporated into the 2020 application;
- Agreed data relating to Heating Degree Days (HDD) to the Environment Canada website, and.
- Reviewed the forecast revenue by dollar and MWh used in Forecast Unit Revenue per MWh for internal consistency with 2020 test year revenues and energy forecast.

10.3. Findings and observations

Calculation of 10 Year Average HDD (Appendix 4, Schedule 1)

MECL uses Environment Canada data from the Charlottetown Airport Weather Station to accurately record HDD, as per Commission Order UE16-04. We compared the components of the calculation of the 10 year average HDD to actuals provided by Environment Canada and we found the following errors:

- June 2018 HDD value as per MECL is 168.4 but Environment Canada states 167.6;
- September 2018 HDD value as per MECL is 124.7 but Environment Canada states 125.7; and
- October 2018 HDD value as per MECL is 341 but Environment Canada states 338.7. We identified this number as an error in previous correspondence, which MECL corrected for the 2019 variables but remained unchanged in the 2020 variables for this schedule.

The impact of these errors was reconciled and recalculated by MECL. This recalculation does not affect the 10-year average HDD of 4386 as originally submitted by MECL. Below we quantify these errors to the Weather Normalization reserve monthly adjustment.

MECL noted that Environment Canada commonly has HDD data missing or estimated. MECL uses the best dataset available at the time of calculation but may not revise the updated HDD data published by Environment Canada in its subsequent WNR calculations. According to MECL, the Company may compensate missing data from the Charlottetown Weather Station and retrieve it from the Harrington Station located near Brackley, PEI, or the Stanhope Station when data from Harrington is also not available. MECL's calculations for final HDD values are included in their monthly HDD downloads from Environment Canada which were provided to us.

9.3.1 MWh per HDD Coefficient (Appendix 4, Schedule 2)

We recalculated the components of the MWh per HDD Coefficient (the "Coefficient") calculation including days in month, average HDD per day, average MWh per day and HDD per day. We also verified the actual HDD against Environment Canada. For reported sales (MWh) included in the calculation we ensured it agreed to monthly sales provided by MECL. For WNR calculations, all revenue and MWh sales variables must exclude seasonal customers, site revenues, and service charges. We asked MECL to provide us with their calculation of MWh sales from July 2018 to June 2019 to exclude the appropriate MWh sales and they did so accordingly. Their MWh sales calculations were recalculated as a part of our process. Based on the HDD errors noted above the following discrepancies were noted:

- September 2018 HDD value as per MECL is 124.7 but Environment Canada states 125.7; and
- October 2018 HDD value as per MECL is 341 but Environment Canada states 338.7. We identified this number as an error in previous correspondence on other schedules, which MECL corrected for the 2019 variables but remained unchanged in the 2020 variables for this schedule.

We recalculated the 2019 Coefficient of 68.07 MWh and ensured that the linear regression formula used to calculate 2019 Coefficient was consistent with the previously approved Coefficient calculations. Due to the adjustments in HDD days, our recalculation found the Coefficient to be 67.91. We asked MECL about the discrepancies and our recalculated change to the Coefficient and their response is as follows:

> *"The changes would reduce the HDD coefficient by 0.16 from the proposed 68.07 to 67.91. The impact cannot be accurately measured given this is the forecast coefficient for 2020 … we provided an estimated impact on the balance had the co-efficient been 0.16 lower since the inception of the WNR account in January 2016 and the cumulative impact is less than $3,500. It is therefore reasonable to assume the impact would not be material."*

MECL did this calculation exercise to show that the impact of adjusting the Coefficient by 0.16 would not be material to the balance of the WNR. We reviewed MECL's calculations and quantified the impact from 2016 to 2019 and agree that it is $3,402 recoverable from ratepayers.

We noted a significant increase in the Coefficient from 2019. The 2019 Coefficient was 50.19 and historical year over year increases to the Coefficient were between 1.48 to 3.53. We asked MECL to provide reasoning behind the increase of 17.88 (68.07 less 50.19) in the Coefficient from 2019 and their response is as follows:

> *"The primary reason the Heating Degree Day coefficient (expressed in units of MWh / Heating Degree Day) has increased is because the heating component of the electricity load has increased. The purpose of the regression analysis shown in Appendix 4 Schedule 2 is to estimate the space heating load on the MECL system. The space heating load is growing due to a high penetration of electric heat in new construction, and ongoing conversions of some of the existing building stock to electric heat. The increase in the coefficient from an estimated 50.19 MWh / HDD for the 2017/2018 heating season to the estimate of 68.07 MWh / HDD for the 2018/2019 heating season is a reflection of this growth in space heating load.*
>
> *It is worth noting that the coefficient is an estimate and there is uncertainty with all estimates. In this case, the uncertainty is expressed by the standard deviation (referred to as standard error in Schedule 2) of the coefficient. For the estimate of 68.07 MWh / HDD, the standard deviation is 6.48, which means that we can be approximately 67 % confident that the true value for the HDD coefficient for the 2018/2019 heating season is within +/- 6.48 of 68.07. The standard deviation for the estimate of 50.19 is 5.35, and similarly we can be approximately 67 % confident that the true value for the HDD coefficient for the 2017/2018 heating season is within +/- 5.35 of 50.19. It is possible that part of the increase can be attributed to the inherent uncertainty associated with these estimates as expressed by their standard deviations."*

Based on our procedures on the MWh per HDD Coefficient and responses provided by MECL, we did not note any further exceptions than noted above.

9.3.2 Calculation of Forecast Marginal Net Revenue Rate (Appendix 4, Schedule 3)

Forecast Unit Revenue per MWh

This component includes forecast revenue and forecast MWh sales on an annual basis for Residential, General Service, and Small Industrial customers. For WNR calculations, all revenue and MWh sales variables must exclude seasonal customers, site revenues, and service charges. We agreed the revenues and the MWh used in Forecast Unit Revenue per MWh to ensure it cross-referenced to 2020 test year revenues and energy forecast and ensured that MECL followed the WNR methodology of excluding seasonal customers, site revenues, and service charges.

Based on forecast sales and revenue data, we recalculated the forecast unit revenue per MWh of $145.29 and did not note any exceptions.

Forecast Unit Energy Cost per MWh

The Energy Cost Adjustment Mechanism ("ECAM") base rate used to calculate marginal net revenue is the proposed $92.25 included in the January 2020 filing (Amended II).

During our review of the WNR, we noted that the ECAM base rate doesn't come into effect until March 1, 2020 but is used in calculating the marginal net revenue rate for the WNR effective January 2020. Additionally, the forecast energy sales data used follows the calendar year from January to December 2020.

Since the introduction of the WNR, the ECAM used in the forecast marginal net revenue rate has been the proposed ECAM rate which comes into effect March 1 each year. MECL was asked why they use the proposed ECAM effective March 1, 2020 to calculate the January 1, 2020 WNR adjustments and their response was as follows:

> *"The Weather Normalization Mechanism and Reserve was first proposed in the 2016 General Rate Application to mitigate the increased volatility resulting from the growing load of electricity sales for space heating. The proposal was based on a calendar year application of the proposed variables including the marginal net revenue beginning on January 1, 2016. This methodology, using the proposed ECAM Base Rate effective March 1, was approved by the Commission on in Orders UE16-04, UE17-01, UE18-02, and UE19-08. The Company continues to consistently apply the same methodology since the Mechanism was approved in 2016. It is the Company's view that changing the marginal net revenue on March 1 instead of January 1 each year would not have a material impact on the adjustments or the account balance..."*

As stated by MECL in their response, the methodology has been approved in previous Commission orders since the introduction of the reserve.

The potential impact of having two marginal net revenue rates, one for January to February and one for March to December, was not calculated as we didn't have the information to do so. With this change the Forecast Unit Energy Cost per MWh would align with Marginal Net Revenue variable on a calendar basis. The potential impact and change to the methodology could be a future consideration for the Commission.

We recalculated the revised Marginal Net Revenue Rate of $53.04 per MWh and did not note any exceptions.

9.3.3 Monthly Change in Weather Normalization Reserve (Appendix 4, Schedule 4)

As a result of the errors noted above in this section, the cumulative and certain monthly adjustments of the WNR since June 2018 were impacted.

MECL had a note on the December 2019 Variation from 10 Year Average HDD variable stating:

> *"December adjustment was made using original estimate of 10 year average HDD of 613.9 instead of updated 10 year average from GT review of 616.7. Adjustment of $7,320 will be reflected in January 2020."*

When asked MECL why they didn't adjust this value and how they plan on incorporating the $7,320 (a balance recoverable from customers) in the January 2020 WNR adjustment, their response was as follows:

> *"The adjustment was not applied to in December 2019 because the Company's financial records for 2019 were closed when the adjustment was found and the amount is not material. The adjustment has been reflected in the Company's January 2020 financial results."*

We also asked MECL to recalculate the monthly adjustment to the reserve based on the HDD discrepancies found in Schedule 1. Those discrepancies were recalculated by Grant Thornton as well as MECL. The table below compares the annual cumulative year end balances as per the originally reported WNR monthly adjustments to the revised WNR monthly adjustments as a result of the errors noted above:

Year End Cumulative Balance of WNR – Balance Owning (Recoverable)			
	Original Appendix 4, Schedule 4	Recaculated Appendix 4, Schedule 4	Difference
2018	$335,978	$336,457	$ (479)
2019	$1,057,328	$1,057,807	$ (479)

When asked about the change in WNR balance up to December 2019, MECL responded:

> *"The updates to the heating degree days in 2018 would increase the balance payable to customers by $479 to $1,057,807. It is the Company's view that this change is not material."*

9.3.4 Disposition of WNR

The WNR normalizes the effects of weather on MECL's sales and energy costs. The purpose of the WNR is to ensure that MECL does not experience an earnings advantage or shortfall as a result of weather conditions. Currently, the reserve variables are considered annually by the Board however the reserve is a regulatory mechanism which does not provide for timely recovery or credit of the accrued balances in the reserve.

As part of this general rate application, MECL has proposed that the balance of the reserve of $1,057,328 as at December 31, 2019 should be included in the proposed 2020 revenue requirement (as a reduction). We can confirm that MECL has included the WNR in the proposed 2020 revenue requirement.

An annual disposition of the reserve would be consistent with current regulatory practice, e.g. Newfoundland Power's annual balances included in its Weather Normalization Reserve account are recovered from or credited to customers through a rate rider mechanism that is re-set each year. MECL does not have an annual rate rider mechanism in place, thus annual disposition of the reserve is not possible under any current regulatory mechanism.

The alternative to an annual disposition would be for the Commission to consider the potential disposition of accrued balances in the reserve during general rate applications, as is proposed in the current GRA. This would be acceptable regulatory practice as well.

The balance could be considered as part of the ECAM or included in revenue requirement either as an addition for recovery or reduction depending on whether it is due from or to customers. As MECL has been directed by the Commission to complete a review of the components of the ECAM, we recommend that WNR is considered during this review. Alternatively, the disposition of the balance through revenue requirement is also acceptable regulatory practice.

10.4. Conclusion

Based on our review and conversations with MECL on our findings, we did not note any further discrepancies and therefore conclude that the WNR variables for 2020 above is in accordance with the approved definition of the Weather Normalization Reserve other than the MWh per HDD Coefficient. Our recalculation found this variable to be 0.16 less at 67.91.

Based on our calculation of monthly WNR adjustments, we did not note any exceptions outside of the $479 adjustment balance owing to customers as at December 31, 2019 and the $7,320 recoverable from customers to be carried into January 2020 according to MECL.

11. Rate of return adjustment ("RORA")

11.1. Background

The Rate of Return Adjustment Account ("RORA") was approved with the purpose of deferring, with interest, any earnings for a given period in excess of the approved returns on average common equity for said period. These accumulated amounts were to be refunded to customers once the PEI Energy Accord ended.

In MECL's November 2018 GRA they proposed:

1. That any residual balance of the pre-2016 RORA deferral account be transferred to the post-2015 RORA deferral account effective March 1, 2019 to refund customers;
2. That the accumulated post-2015 RORA account be refunded to customers over the period March 1, 2019 to February 28, 2022 by applying a credit of $0.00250/kWh to the per kWh rate for each rate class; and
3. That the disposition of any residual remaining balance in the RORA to be refunded or recovered would be subject to Commission review in the next General Rate Application.

Post November 2018 GRA, MECL filed their July 2019 Update, including updated RORA schedules, which replaced the November 2018 GRA forecasts with up to date actuals at the time of the July 31, 2019. Overall, Pre-2016 RORA Payable to Customers changed from $768,700 to $Nil and the Post-2015 RORA Payable to Customers increased from $9,767,400 to $9,772,685.

The table below outlines the RORA account consistent with the July 2019 Update.

Payable to Customers ($)				
Rate of Return Adjustment (RORA) - Post-2015				
Year	RORA	Interest	Refunded to Customers	Balance Owing to Customers
2016	$ 2,100,000	$ -	$ -	$ 2,100,000
2017	2,767,885	61,922	-	4,929,807
2018	5,239,809	182,419	-	10,352,035
YTD 2019	-	200,135	(779,485)	9,772,685
Total	**$ 10,107,694**	**$ 444,476**	**$ (779,485)**	**$ 9,772,685**

In Order UE 19-08 the Commission outlined the following orders for the Rate of Return Adjustment:

1. MECL shall refund the balance of the post-2015 RORA account, together with interest, to ratepayers commencing March 1, 2020;
2. The RORA balance shall be used to minimize the proposed rate increase for the period March 1, 2020 to February 28, 2021;
3. In the event the balances of the post-2015 RORA account is sufficient to ensure that there is no rate increase effective March 1, 2020, yet there is still a balance remaining in the post-2015 RORA account, the remaining balance shall be refunded to ratepayers during the period from March 1, 2021 to February 28, 2022;
4. The RORA refund rates shall be such that the post-2015 RORA account shall be fully refunded to ratepayers, and shall therefore have a zero balance, on or before February 28, 2022;
5. The RORA account shall not be used as a deferral account to collect over-earnings during the current rate setting period. Instead, any over-earnings earned in 2019, 2020 and/or 2021 shall be determined by the Company as at December 31 of each year, and refunded to ratepayers on a per kWh basis within 60 days of the calendar year-end;

6. The Company shall file with the Commission, on or before January 31 in each of 2020, 2021 and 2022, the balance of the RORA account as at December 31 in the preceding year, together with the proposed per kWh refund (if any); and

7. The Company shall continue to file the balance of the RORA account with the Commission on a monthly and annual basis.

Subsequent to this order in Order UE 19-11 the Commission ordered that MECL is not required to refund the balance of the 2019 RORA account within 60 days of the calendar year-end (as ordered in #5 noted above), and instead, the use and potential refund of the 2019 RORA balance shall be deferred and considered as part of the January 31, 2020 financial update.

11.2. Procedures

Our procedures with respect to verifying the calculation of the rate of return adjustment were directed towards the assessment of the reasonableness of the data incorporated in the calculations and the methodology used by the Company. Specifically, the procedures which we performed included the following:

- Checked the clerical accuracy and continuity of the calculation of the rate of return adjustment for 2019 actuals;
- Reviewed the calculation of the RORA for compliance with Commission Orders; and,
- Reviewed the Company's use of the RORA over the period from 2016 to 2019.

11.3. Findings and observations

10.3.1 Pre-2016 RORA Payable to Customers

In the November 2018 GRA, MECL presented a forecast December 31, 2018 RORA balance of $1,608,800 and forecast February 28, 2019 RORA balance of $768,700. As March 1, 2019 rates did not proceed as proposed in the MECL November 2018 GRA, the Company continued to refund the Pre-2016 RORA Payable to customers in March and April 2019, refunding the full balance to customers by April 2019. We verified the refund by reviewing the Company's actual monthly continuity of the Pre-2016 RORA Payable to Customers. During our review we noted that the December 31, 2017 actual Pre-2016 RORA balance of $6,080,482 and December 31, 2018 actual Pre-2016 RORA balance of $1,558,405 agreed to MECL's audited financial statements, and that the Company refunded the $1,558,405 RORA balance, along with monthly interest to customers by April of 2019.

10.3.2 Post-2015 RORA Payable to Customers

The table below presents the actual and forecast amounts included in the RORA balance, including RORA additions, interest, and refunds for the period of 2016 to February 29, 2020:

Payable to Customers ($)					
Rate of Return Adjustment (RORA)					
Year	RORA	Interest	Refunded to Customers	Proposed Writeoff to Dorian Storm Deferral	Balance Owing to Customers
2016	$ 2,100,000	$ -	$ -	$ -	$ 2,100,000
2017	2,767,885	61,922	-	-	4,929,807
2018	5,239,809	182,419	-	-	10,352,035
2019 - interest and refunds	-	372,782	(2,868,073)	-	7,856,744
Forecast Refund Jan - Feb 2020	-	-	(879,326)	-	6,977,418
Sub-total Post-2015 RORA	**$ 10,107,694**	**$ 617,124**	**$ (3,747,399)**	**$ -**	**$ 6,977,418**
2019 - RORA	**$ 3,509,123**	**$ -**	**$ -**	**$ (3,002,882)**	**$ 506,241**
TOTAL RORA Balance Available for Refund					**$ 7,483,659**

As seen in the table above, the details of the RORA components are as follows:

- RORA: the 2019 RORA balance is due to the variances between forecast and actuals related to revenues and expenses for revenue requirement.
- Interest: interest is calculated at Scotiabank Prime, the Company's cost of short-term borrowing.
- Refunded to customers: the refund for 2019 is the total monthly rebates to customers from April to December of 2019. The forecast 2020 refund is calculated based on the forecast January and February 2020 energy sales, multiplied by the RORA 2019 rebate rate of $0.00345 per kWh.
- Proposed Write-off to Dorian Storm Deferral: balance is based on the balance approved in Order UE 19-11.
- Balance Owing to Customers: these balances have been reconciled and agreed to the audited financial statements of MECL for the corresponding years.

The Post-2015 RORA balance owing to ratepayers is $6,977,418 before 2019 RORA. A 2019 RORA balance addition of $3,509,123 is added to the post-2015 RORA balance, offset by the proposed write-off for Storm Dorian deferral costs of $3,002,882, for a total of $7,483,659 owing to ratepayers.

10.3.3 Calculation of RORA Refund for Remaining Balance as of 2020

Pursuant to UE 19-08 the Company was required to completely refund the balance in the RORA account to ratepayers before February 28, 2022, using the RORA to minimize the proposed rate increase from March 1, 2020 to February 28, 2021. Therefore, MECL has proposed a rate rider to be used to refund the RORA balance by February 28, 2021.

The table below presents MECL's proposed plan to refund the RORA balances to ratepayers in 2020:

Proposed Refunds March 1, 2020 - February 28, 2021	
Rate of Return Adjustment (RORA)	
Opening Balance Payable to Customers	**$ 7,483,659**
Forecasted Energy Sales (KWh)	1,354,147,389
RORA Refund Rate	$ 0.0055
Total Refunds	**$ 7,483,659**
Ending RORA Balance	**$ -**

As seen above MECL proposes a RORA refund rate of $0.0055 per kWh. This rate will allow MECL to forecast the refund of RORA balance fully by February 28, 2021 as directed by the Commission. The forecasted energy sales used in the RORA refund rate are consistent the Company's energy sales as reviewed in our Energy Sales section, and the rate was included within rate riders in the January 2020 filing (Amended II) to be included on base rates from March 1, 2020 to February 28, 2021.

10.3.4 Historical review of RORA – 2016 to 2019

The tables below display the differences between the actuals versus forecasts for the components which calculate the 2016, 2017, 2018 and 2019 RORA balances, in addition to variance explanations:

Actual vs. Forecast ($)								
	2016				2017			
	Actual	Forecast	Difference	Note	Actual	Forecast	Difference	Note
Total Gross Electric Revenue	$ 178,157,321	$ 178,952,200	$ (794,879)	1	$ 185,326,722	$ 187,114,200	$ (1,787,478)	4
Total Other Revenue	10,154,053	9,735,100	418,953	2	9,924,288	14,404,700	(4,480,412)	5
Total Revenue Excluding Adjustments	**$ 188,311,374**	**$ 188,687,300**	**$ (375,926)**		**$ 195,251,010**	**$ 201,518,900**	**$ (6,267,890)**	
Operating Expenses (Net of ECAM)	$ 134,018,878	$ 136,249,800	$ (2,230,922)	3	$ 138,579,062	$ 147,181,200	$ (8,602,138)	6
Interest Expense (including amortization of Debt Issue Costs)	12,378,373	12,388,000	(9,627)		12,251,808	12,433,300	(181,492)	
Amortization – Fixed Assets	20,942,072	21,045,600	(103,528)		21,802,450	21,981,400	(178,950)	
Amortization – DSM Costs	-	-	-		327,676	322,500	5,176	
Amortization – Lepreau Writedown	97,362	93,400	3,962		93,400	93,400	-	
Income Tax Expense	5,959,260	5,976,200	(16,940)		6,130,460	6,160,100	(29,640)	
Return on Equity	12,941,456	12,934,300	7,156		13,350,422	13,347,000	3,422	
Total Expenses	**$ 186,337,401**	**$ 188,687,300**	**$ (2,349,899)**		**$ 192,535,278**	**$ 201,518,900**	**$ (8,983,622)**	
Total Expenses less Revenues	$ (1,973,973)	$ -	$ (1,973,973)		$ (2,715,732)	$ -	$ (2,715,732)	
Less Adjustment: Weather Normalization	126,031	-	126,031		52,155	-	52,155	
Total Including Adjustments	**$ (2,100,004)**	**$ -**	**$ (2,100,004)**		**$ (2,767,887)**	**$ -**	**$ (2,767,887)**	

Note - Actuals from Amendment to Application for Schedule of Rates, filed Feb 14, 2020.
Forecasts from MECL's amended and updated support of the 2016 GRA, filed February 5, 2016.

The 2016 variances noted above were inquired with MECL and provided us with the following responses:

- **Note 1 -** Residential and general service customer sales were over forecasted by $384,000 and $996,000 respectively. For residential approximately $32,000 and $338,000 of the variance resulted from both lower than forecast kWh sales and unit revenue respectively. For general service approximately $750,000 and $233,000 of the variance resulted from both lower than forecast kWh sales and unit revenue respectively. Over forecasting was partially offset by small industrial customers and street lighting gross electric revenue by $365,000 and $282,000 respectively. For small industrial customers approximately $145,000 and $221,000 of the variance was the result of both higher than forecast kWh sales and unit revenue respectively. For street lighting approximately $33,000 and $250,000 of the variance resulted from both higher than forecast kWh sales and unit revenue respectively.
- **Note 2 -** Actuals were higher than forecast by $418,000, which was primarily due to OATT revenue being approximately $281,000 higher than forecast mainly due to recovery of imbalance charges flowing through to OATT customers. Additionally, other revenues were approximately $136,000 higher than forecast mainly due to increased penalty charges ($64,000) and increased accrued revenue ($52,000).
- **Note 3 –** Actual was lower than forecast by $2,230,000 due to several reasons. Aapproximately $800,000 lower than expected due to lower than expected sales as a result of a milder winter, as seen in the table above for total gross electric sales. Transmission and distribution expenses were approximately $900,000 lower than forecast due to lower than expected expenses for transmission line rights of way tree trimming costs, lower transmission and distribution line maintenance costs and property taxes. Corporate Services and Support was approximately $700,000 lower than expected due to lower customer service costs, regulatory costs and employee future benefit costs. These savings were slightly offset by higher transmission OATT expenses of $175,000.

The 2017 variances noted above were inquired with MECL and provided us with the following responses:

- **Note 4 -** Residential and general service customer sales were over forecasted by $890,000 and $1,639,000 respectively. For residential approximately $560,000 and $316,000 of the variance results from both lower than forecast kWh sales and unit revenue respectively. For general service approximately $1,568,000 and

$60,000 of the variance resulted from both lower than forecast kWh sales and unit revenue respectively This over forecasting was partially offset by large industrial customers and street lighting gross electric revenue by $273,000 and $324,000 respectively. For large industrial customers approximately $163,000 and $107,000 of the variance was the result of both higher than forecast kWh sales and unit revenue respectively. For street lighting approximately $50,000 and $274,000 of the variance was the result of both higher than forecast kWh sales and unit revenue respectively.

- **Note 5 -** Actuals were lower than forecast by $4,480,000, which was primarily due to lower than expected OATT revenue of approximately $4,418,000. When the 2016 GRA was prepared, the forecast charges for the new interconnection cable lease (10 months in 2017 = $3,345,000) were proposed to be collected from all transmission customers (including MECL) through the OATT. Under debt collection agreement signed between the PEIEC, the City of Summerside (10.1%) and MECL (89.9%) are responsible to pay for their respective share of the lease costs rather than recovering from all transmission customers through the OATT. Additional OATT revenue of approximately $788,000 for the recovery of charges from NB Power for facilities dedicated to the interconnection cables were forecast to begin in July 2017. The new OATT including recovery of these costs was approved by Commission Order UE18-05 on August 1, 2018.

- **Note 6 –** Approximately $4,675,000 relates to the lower OATT costs mainly related to the new cable interconnection originally proposed to flow through the OATT (as discussed in Note 5). Energy costs were approximately $1,600,000 lower than expected energy costs, net of ECAM due to lower than expected sales due to lower than expected load growth. Transmission and distribution costs were approximately $975,000 lower than expected mainly due to lower line and transformer maintenance costs due to low storm activity in 2017 and lower property tax costs than expected. Corporate Costs were approximately $1,425,000 lower than forecast due to lower customer service costs, lower finance and regulatory costs, and lower corporate services and support costs

Actual vs. Forecast ($)								
	2018				2019			
	Actual	Forecast	Difference	Note	Actual	Forecast	Difference	Note
Total Gross Electric Revenue	$ 196,681,177	$ 194,705,200	$ 1,975,977	1	$ 201,654,318	$ 200,498,600	$ 1,155,718	4
Total Other Revenue	12,293,300	15,915,500	(3,622,200)	2	13,341,923	12,161,000	1,180,923	5
Total Revenue Excluding Adjustments	**$ 208,974,477**	**$ 210,620,700**	**$ (1,646,223)**		**$ 214,996,241**	**$ 212,659,600**	**$ 2,336,641**	
Operating Expenses (Net of ECAM)	$ 147,386,372	$ 154,201,300	$ (6,814,928)	3	$ 153,485,663	$ 153,120,200	$ 365,463	
Interest Expense (including amortization of Debt Issue Costs)	12,618,847	12,644,900	(26,053)		12,901,422	12,637,300	264,122	
Amortization – Fixed Assets	22,583,378	22,983,800	(400,422)		23,337,238	25,871,500	(2,534,262)	6
Amortization – DSM Costs	524,050	573,000	(48,950)		157,198	167,000	(9,802)	
Amortization – Lepreau Writedown	93,400	93,400	-		93,400	93,400	-	
Income Tax Expense	6,266,588	6,350,300	(83,712)		6,483,242	6,529,500	(46,258)	
Return on Equity	13,792,864	13,774,000	18,864		14,262,630	14,240,700	21,930	
Total Expenses	**$ 203,265,499**	**$ 210,620,700**	**$ (7,355,201)**		**$ 210,720,793**	**$ 212,659,600**	**$ (1,938,807)**	
Total Expenses less Revenues	$ (5,708,978)	$ -	$ (5,708,978)		$ (4,275,448)	$ -	$ (4,275,448)	
Less Adjustment: Weather Normalization	(469,169)	-	(469,169)		(766,345)	-	(766,345)	
Total Including Adjustments	**$ (5,239,809)**	**$ -**	**$ (5,239,809)**		**$ (3,509,103)**	**$ -**	**$ (3,509,103)**	

Note - Actuals from Amendment to Application for Schedule of Rates, filed Feb 14, 2020.
Forecast for 2018 from MECL's amended and updated support of the 2016 GRA, filed February 5, 2016.
Forecast for 2019 from MECL's November 2018 GRA, filed November 30, 2018.

The 2018 variances noted above were inquired with MECL and provided us with the following responses:

- **Note 1 -** The large industrial and residential customers gross electric revenue was under forecasted by $2,253,000 and $1,678,000, respectively. For large industrial customers, as stated above, three small industrial customers were reclassified into the large industrial rate class in late 2017. For residential customers, approximately $2,764,000 of the variance was the result of higher than forecast kWh sales and $1,104,000 of the variance was partially offset by lower than forecast unit revenue. This under forecasting was partially offset by general service and small industrial customers were each over forecasted by

$707,000 and $1,617,000 respectively. For general service approximately $694,000 and $16,000 of the variance results from lower than forecast kWh sales and lower than forecast unit revenue, respectively. For small industrial customers, three customers in this rate class were reclassified to the large industrial rate class in late 2017, as per MECL's November 2018 GRA.

- **Note 2 -** actuals were lower than forecast by $3,622,000, which was primarily due to lower than expected OATT transmission revenue of $4,511,000. When the 2016 GRA was prepared, the forecast charges for the new interconnection cable lease (12 months in 2018 forecast = $4,015,000) were proposed to be collected through the OATT. Under debt collection agreement signed between the PEIEC, the City of Summerside (10.1%) and MECL (89.9%) are responsible to pay for their respective share of the lease costs rather than recovering from all transmission customers through the OATT. The lower than forecast OATT revenue was partially offset by an increase in Miscellaneous Revenue of $888,000. This was primarily the result of an unexpected refund of $950,000 received in November 2018 from the Province of PEI for Rights of Way fees collected from MECL from 1998-2001.
- **Note 3 –** Approximately $5,000,000 relates to lower than forecast OATT costs mainly related to the new cable interconnection originally proposed to flow through the OATT. Transmission and distribution costs were $1,200,000 lower than expected mainly due to lower rights of way line clearing costs, lower line maintenance costs and lower property tax costs than expected. Corporate Costs were $1,400,000 lower than forecast due to lower customer service costs and lower corporate services and support costs. These lower costs were partially offset by higher energy costs net of ECAM of $700,000 higher than forecast due to higher than expected sales as a result of higher than expected load growth.

The 2019 variances noted above were inquired with MECL and provided us with the following responses:

- **Note 4 –** The residential customers were under forecasted by $1,992,000, which was primarily due to the change in forecasting methodologies of energy sales, which in turn had actual energy sales of 20.3 GWh higher than forecast, as seen in our energy sales section of this report. This was partially offset by the over forecasting for the general service and small industrial customers by $552,000 and $199,000 respectively. For general service approximately $503,000 resulted from higher than forecast kWh sales and this was offset by approximately $1,054,000 lower than forecast unit revenue. For small industrial customer approximately $372,000 resulted from lower than forecast kWh sales and this was partially offset by approximately $169,000 higher than forecast unit revenue.
- **Note 5 -** actuals were higher than forecast by $1,180,000, which was primarily due to higher than expected OATT transmission revenue.
- **Note 6 -** Amortization – Fixed Assets: actuals were lower than forecast by $2,534,000 primarily due to the delay in adopting new depreciation rates, as per UE19-08. When the 2017 Depreciation Study was completed by Gannett-Fleming, MECL assumed new depreciation rates for the CTGS would come into effect in 2019. This was incorporated into MECL's November 2018 GRA.

10.3.5 Interest charged to RORA

As part of our review of RORA, we noted that the interest is calculated at the bank prime rate to reflect MECL's short term borrowing rate as opposed to the Company's weighted average cost of capital. We asked MECL for an explanation on this matter and MECL's response was as follows:

> "*As per Order UE11-04… the Company has accrued interest at its short-term borrowing rate since RORA was first introduced in 2011.*
>
> *The Company considers a short-term borrowing rate reasonable given the time frame that a given RORA balance is proposed to be refunded. For example, in the 2016 General Rate Agreement, the Company forecast a return of the pre-2016 RORA balance over the three years of the agreement (March 1, 2016 – February 28, 2019). In the current Application before the Commission, the Company is proposing a refund of the RORA balance on December 31, 2019 in one year (March 1, 2020 – February 28, 2021).*
>
> *It is also worth noting that, had the Company accrued interest at its weighted average cost of capital instead of its short term borrowing rate, this would have increased the payable to customers annually by the*

difference between the short term borrowing rate and the Company's WACC. However, in any given year, the resulting increase in interest expense would have reduced the RORA realized in that year. The two would offset each other and the net impact to the overall RORA balance would be nil."

We agree with MECL's comments that if RORA is charged at the short-term borrowing rate then the proposed revenue requirement would also include interest at the short-term borrowing rate, and vice versa if WACC was charged. Additionally, we agreed that historically the RORA has been charged at its short-term borrowing rate.

However, we recommend the Commission consider whether a change is required in how interest is to be charged on RORA, and more specifically whether the short term borrowing rate is an appropriate rate to be charged given that RORA is a component of rate base where its components earn (or pay) a return based on the Company's WACC (or return on average rate base).

10.3.6 Notional RORA for period ended June 30 and May 31, 2020

During our review we requested that MECL provide a calculation of the RORA balance for the five-month period ended May 31, 2020 assuming that May 31st was the end of the reporting period for 2020.

In GT-RFI-2019-97 MECL provided the calculation with a comparison of the Notional RORA for year to date (YTD) results for May and June of 2020 compared to 2019. The YTD June 2020 and May 2020 earnings are tracking approximately $2.0 million and $1.3 million below the YTD budget. Pursuant to Order UE16-04 the Company is not permitted to recover any amounts from RORA in the event it does not attain its approved return on average common equity in a given year, therefore no amount has been accrued for recovery by MECL. MECL has accrued notional quarterly RORA adjustments in prior years when YTD earnings are tracking ahead of the YTD budget, e.g. in 2019 the Company accrued $3.3 million in RORA by June 30, 2019.

11.4. Conclusion

Based on the results of the above procedures, we find that the RORA balances from the 2016 to 2019 period were mathematically correct and in compliance with Commission Orders. We recalculated the proposed RORA refund rate rider of $0.0055 per kWh and found no exceptions.

12. Proposed revenue from rates

12.1. Background

The rates, tolls and charges for electric service in effect for the period from March 1, 2018 to February 28, 2019 were ordered to remain in effect until February 28, 2020, or unless otherwise varied by the Commission, in Order UE19-08. The Company filed updated financial information in their January 31, 2020 (Amended II) filing, which includes proposed rates for 2020 and 2021.

12.2. Procedures

Our procedures with respect to verifying the calculation of the electricity sales revenues from rates were directed towards the accuracy of the data incorporated in the calculations and methodology used by the Company for revenue requirement purposes. Specifically, the procedures which we performed included the following:

- Recalculated the revenue in each customer class that results from using the proposed rates by customer, ensuring that it agrees with revenue requirement submitted by the Company;
- Agreement of the inputs used in the revenue calculations (i.e. energy sales forecast, customers, rates) to those presented by the Company;
- Agreement of the rates used in the revenue calculations to those in the proposed Schedule of Rates;
- Compared actual revenues in 2019 to forecast revenues to assess any significant trends; and
- Reviewed percentage increases in final customer class rates.

12.3. Findings and observations

Our recalculation of revenue presented in each customer class in MECL's supporting documentation agrees with annual totals for 2019, 2020, and 2021 presented in MECL's January 31, 2020 (Amended II) filing, schedule 9-13 "Energy Sales by Class (Proposed Basic Rates)" as seen below:

Energy Sales by Class (Proposed Basic Rates)				
	2019A	2020F	2021F	2021F vs 2019A
Energy by Class - (GWh)				
Residential	641.0	676.7	707.4	66.4
General Service I	392.8	403.2	412.6	19.8
Large Industrial	154.0	159.5	161.0	7.0
Small Industrial	91.7	94.3	96.5	4.8
Street Lighting	4.9	4.8	4.5	(0.4)
Unmetered	2.5	2.5	2.5	-
Total Energy Sales	**1,286.9**	**1,341.0**	**1,384.5**	**97.6**
Gross Revenue by Class ($)				
Residential	108,630,752	115,516,900	120,252,200	11,621,448
General Service I	63,552,897	65,818,000	67,174,200	3,621,303
Large Industrial	13,944,113	14,366,200	14,277,400	333,287
Small Industrial	12,767,732	13,200,900	13,451,800	684,068
Street Lighting	2,323,872	2,307,400	2,197,500	(126,372)
Unmetered	434,952	427,600	432,000	(2,952)
Total Gross Electric Revenue	**201,654,318**	**211,637,000**	**217,785,100**	**16,130,782**
Rate of Return Adjustment	(3,509,123)	3,002,900	-	3,509,123
Weather Normalization Adjustment	(766,345)	1,057,300	-	766,345
Total Electric Revenue	**197,378,850**	**215,697,200**	**217,785,100**	**20,406,250**
Total Other Revenue	**13,341,923**	**13,425,300**	**13,217,400**	**(124,523)**
Total Revenue	**210,720,773**	**229,122,500**	**231,002,500**	**20,281,727**

The same annual totals presented above agree with the annual totals presented in schedule 9-10 “Revenue Requirement ($)” of the January 2020 filing (Amended II). The total gross electric revenues trends year over year are in line with both the rate and energy sales increases for the 2019 to 2021 period.

Our agreement of the inputs used in revenue calculations presented in MECL’s January 2020 filing (Amended II) in schedule 9-13 “Energy Sales by Class (Proposed Basic Rates)” agree with annual revenue totals presented in MECL’s response to our request.

We were able to agree that rates used in each customer class in MECL’s response to our request for 2019, 2020, and 2021 agree with MECL’s January 2020 (Amended II) filing in Appendix 1 “Schedule of Rates” with the following exceptions:

- Street Lighting basic rates presented in MECL’s January 2020 filing (Amended II), Appendix 1 “Schedule of Rates”, do not agree with the Street Lighting basic rates presented in MECL’s response to our request; and
- Unmetered basic rates presented in MECL’s January 2020 filing (Amended II), Appendix 1 “Schedule of Rates”, do not agree with the Unmetered basic rates presented in MECL’s response to our request.
- When asked about the disagreement of rates presented in in MECL’s response to our request and MECL’s January 31, 2020 (Amended II) filing, Appendix 1 “Schedule of Rates”, the Company’s response is as follows:

  “*For both the Unmetered Rate and Streetlight rates presented in Appendix 1 – Schedule of Rates, the rates presented are based on the current approved rate multiplied by the target annual increase in cost per customer (1.1% in 2020 and 1.2% in 2021) as presented in Schedules 11-1, 11-2, and 11-3 in the Application.*

  The unmetered rate and streetlights revenue forecast presented in GT-RFI-2019-32 and 38, forecast only the basic revenue (or revenue requirement) component of the total charge proposed in Appendix 1. In addition to revenue requirement, the rates proposed in Appendix 1, include ECAM, Provincial Costs Recoverable, Provincial Energy Efficiency Program, Cable Contingency and RORA amounts as set out in Schedule 11-4, Energy Charges per kWh – Other Amounts(B).

In the attached spreadsheet GT-RFI-2019-67 Unmetered and Streetlights.xlsx, the Company has provided a reasonableness test of the revenue forecast for unmetered and streetlight revenue with the rates proposed in Appendix 1 after the charges for other amounts are removed (i.e. Basic revenue).

The difference between the reasonability test for unmetered revenue and the forecast unmetered revenue in the Application is $6,700 in 2020 and $6,400 in 2021. The difference between the reasonability test for streetlight revenue and the forecast streetlight revenue in the Application is $(11,200) in 2020 and $(5,200) in 2021. The Company considers both differences to be immaterial and considers the forecast revenue for unmetered and streetlights to be reasonable."

We were able to agree the inputs MECL used in their reasonability test in MECL's response to our request as well as recalculate the reasonability test provided. The difference in forecast revenues provided in MECL's model compared to the January 2020 filing (Amended II) were understated for the Street Lighting rate class and overstated in the Unmetered rate class. This is due to the difference in rates use in MECL's model compared to the proposed rates in Appendix 1 of the January 2020 filing (Amended II).

Based on our procedures completed above as well as MECL's responses, we do not note any material exceptions.

Our recalculation of the year over year increase in final rates (base rates plus rate riders) below are based off using the Company's section 11 final rates within MECL's January 2020 filing (Amended II):

Customer Class	2019A	2020F	2021F	2020F vs 2019A	2021F vs 2020F
Residential - First Block	$ 0.1437	$ 0.1457	$ 0.1479	1.4%	1.5%
Residential - Second Block	$ 0.1142	$ 0.1157	$ 0.1180	1.3%	2.0%
General Service - First Block	$ 0.1767	$ 0.1794	$ 0.1815	1.5%	1.2%
General Service - Second Block	$ 0.1154	$ 0.1170	$ 0.1193	1.4%	2.0%
Small Industrial - First Block	$ 0.1731	$ 0.1758	$ 0.1779	1.6%	1.2%
Small Industrial - Second Block	$ 0.0872	$ 0.0883	$ 0.0907	1.3%	2.7%
Large Industrial	$ 0.0714	$ 0.0724	$ 0.0734	1.4%	1.4%

The yearly increase in rates is primarily due to increased revenue requirement which increases base rates and the impact of rate riders applied to base rates each year.

12.4. Conclusion

Based on our procedures nothing has come to our attention to indicate that the forecast gross electric revenues from rates for 2020 and 2021 appear unreasonable.

Based on our procedures we find that the revenue requirement proposed by the Company is calculated based up on the Schedule of Rates filed in Appendix 1 effective March 1, 2020 as outlined in the January 2020 filing (Amended II).

13. Amortization rates

13.1. Background

The table below summarizes the existing depreciation rates last approved by the Commission in Order UE 16-04 along with the annual depreciation rates recommended by Gannett Fleming in the 2017 Depreciation Study, to be implemented and effective January 1, 2020:

Existing and Recommended Depreciation Rates by Asset Class (%)		
Asset Class	**2019**	**2020**
Production Plant		
Charlottetown Thermal Generating Station*	7.99	13.06
Borden Generating Station	4.81	5.83
Combustion Turbine #3	2.28	2.49
Transmission Plant	2.27	2.42
Distribution Plant	3.32	3.72
General Plant	5.96	6.00

*2019 rate is comprised of Depreciation - 4.53% and Accumulated Reserve Variance Amortization - 3.46%.

In UE 19-08 the Commission ordered that:

1. MECL shall adopt all the recommendations made by Gannett Fleming in the 2017 Depreciation Study. This includes, without limitation, the adoption of the proposed depreciation rates and the amortization of the accumulated reserve variance for all assets;
2. The depreciation rates and amortization of the accumulated reserve variance shall be adopted as of January 1, 2020, and shall be included in the Company's revenue requirement for rates effective March 1, 2020 and March 1, 2021; and
3. MECL shall undertake a new depreciation study based on financial results up to December 31, 2020. The depreciation study shall be filed with the Commission no later than June 30, 2021.

13.2. Procedures

Our procedures with respect to the calculation of amortization expenses were directed towards the accuracy of the data incorporated in the calculations and compliance with the Commission's orders. Specifically, the procedures which we performed included the following:

- Agreed all amortization rates within the January 2020 filing (Amended II) to those recommended in the 2017 Depreciation Study by Gannett Fleming; and
- Recalculated the Company's forecasted amortization for 2020 and 2021.

13.3. Findings and observations

In Order UE19-08 the Commission approved MECL's use of the amortization rates and methodology including the approval of the accumulated reserve variance to be amortized over the average remaining service life of the related assets, as recommended in the 2017 Depreciation Study on the calculation of its amortization expense effective January 1, 2020.

The table below summarizes amortization expenses from 2018 to 2021:

Amortization - Property Plant & Equipment (PPE)				
	2018A	2019A	2020F	2021F
Amortization - PPE (Excluding CTGS)	$ 17,731,770	$ 18,587,787	$ 21,522,859	$ 22,846,956
Amortization - CTGS	4,851,608	4,749,451	7,049,241	3,355,344
Total Amortization - PPE*	**$ 22,583,378**	**$ 23,337,238**	**$ 28,572,100**	**$ 26,202,300**
Year Over Year Change (%)		**3.3%**	**22.4%**	**-8.3%**

*Excluding amortization on DSM and LePreau writedown.

Amortization recorded by MECL during 2018 and 2019 is calculated based on the depreciation rates approved in Order UE16-04. The 2020 and 2021 forecast amortization expenses are based on the rates recommended in the 2017 Depreciation Study.

The increase in annual amortization expense for PPE for the years 2020 and 2021 over 2018 and 2019 is primarily the result of the Company's annual capital expenditures and adoption of new amortization rates recommended in the 2017 Depreciation Study by Gannett Fleming

The decrease from 2020 to 2021 is due to the CTGS amortization as seen above, which is primarily due to the retirement of the assets.

13.4. Conclusion

Based on our review, amortization expenses presented by MECL for 2020 and 2021 forecasts are calculated using the 2017 Depreciation Study recommended rates. Furthermore, we recalculated the amortization expenses for the forecast years without identifying any material errors and conclude that the amortization expense is calculated in accordance with the rates prescribed in the 2017 Deprecation Study.

14. General rules and regulations

14.1. Background

In accordance with section 20(1) of the Electric Power Act, the Company is required to file with their General Rate Application a copy of all rules and regulations which, in any manner, relate to the rates, tolls and charges. The Company filed an amended General Rules and Regulations (“GRR”) in the November 2018 GRA filing. These amendments were to incorporate the following:

- Changes to the Residential monthly service charge;
- Changes to the ECAM base rate;
- Changes to the rates for each rate class, as proposed by MECL; and,
- Amend Large Industrial Rate Schedule Guidelines to reflect a more accurate and complete description of the charges.

No revisions were provided for the General Rules and Regulations within the July 2019 Update filing to the Commission.

Resulting from the Order UE19-08, the Commission approved the amendments to the Large Industrial Rate Schedule Guidelines as proposed above, which were to be filed with the Commission on or before October 31, 2019. The other changes proposed by MECL were not approved in UE19-08.

14.2. Procedures

The following procedures were completed during our review of the amended General Rules and Regulations:

- Reviewed the approved amendments as per UE19-08 and ensured that they are incorporated in the General Rules and Regulations filed with the Commission on October 31, 2019;
- Reviewed the Large Industrial rate class schedule provided by MECL in GT-RFI-2019-53 to ensure they incorporated the amended rules in the January 31, 2020 (Amended II) filing; and
- Verified any proposed changes to the General Rules and Regulations that were not approved in UE19-08 were not incorporated in the October 31, 2019 updated General Rate Application filing nor the January 31, 2020 (Amended II) filing.

14.3. Findings and observations

13.3.1 Interim Customer Owned Street and Area Lighting Rates

Based on the approved amendments to the General Rules and Regulations in UE19-08, we found that MECL appropriately incorporated the terms of that order. During our review, there was an additional amendment to the General Rules and Regulations in the October 31, 2019 filing. This amendment has been applied to the January 31, 2020 (Amended II) filing. This change is as follows:

Revisions to Sections N-24 and N-28 were included to add two new rates for Customer Owned Street and Area Lighting as permitted in Section N-25 of the General Rules and Regulations:

MECL's Oct. 31, 2019 GRR Update		
Rate Code	Wattage/Description	Rate per Month
651	19W LED St Lights - Owned	$1.13
652	60W LED St Lights - Owned	$3.56

Under Section N-25, MECL may require new rate codes to coincide with a Customer's request for Service for a Customer owner street and area lighting fixture other than the categories that MECL already has listed. This section states "The interim rate for these new fixtures will be calculated using the formula below, as approved by IRAC." The formula is as follows:

Interim rate for new fixtures formula (N-25)	
Basic Rate	(4,100 hrs x W/1000 x U) divided by 12 months
Where:	
4,100 hours	equals the number of hours the fixture is on during the year
W	equals the total wattage of the fixture, ballast and any other apparatus associated with the fixture
U	equals the basic Un-metered Service energy rate from Section N-17 of the approved tariff

Section N-17 states the unmetered service energy rate as 17.38¢ per kWh of estimated consumption. Based on the variables provided, we recalculated the new interim rates as follows:

- Rate Code 651 (19W) = (4,100 hrs)(0.019 W)(0.1738 ¢)/12 months = $1.128
- Rate Code 652 (60W) = (4,100 hrs)(0.06 W)(0.1738 ¢)/12 months = $3.563

These calculations align with the interim rates calculated by MECL for rate codes 651 and 652. MECL is seeking approval of the new interim rates within their October 31, 2019 submission.

13.3.2 Large Industrial Rate Schedule

It is MECL's practice to gather forecast increases for large industrial customers directly from the customer. This was asked to MECL in GT-RFI-2019-13. Their answer was as follows:

> *"…There are currently a total of seven customers in this rate class and the forecast for these customers is updated on a case by case basis. For new loads, the size and timing is described in comments in the respective year 2019 cells. This is based on information provided by the customer when applying for service and used by MECL to determine the size of the transformer that will be needed to supply the load. For existing loads, the trend in usage in recent years is assumed to continue into the future."*

We were unable to verify the percentage increases indicated by MECL's customers, as well as the timing of those increases, due to customer confidentiality.

As per MECL's approved General Rules and Regulations amendment in UE19-08, the Rental Charge as per N-9 in the GRR, file October 31, 2019, is as follows:

> Primary distribution voltage to customer's utilization voltage:
>
> At the Customer's request, Maritime Electric will supply, own and maintain the substation equipment at the Customer's premises, including from the primary distribution voltage switches to the low voltage terminals of the step-down transformers, provided such transformation satisfies Maritime Electric Standards. The charge for such rental equipment is 1 5/6% per month of the installed costs. The Customer will supply the low voltage switch gear, concrete substation foundation pads and necessary protective fencing.

Based on MECL's large industrial customer revenue calculations, there is a rental charge included of 1 5/6 percent (1.83 percent as depicted in MECL's calculation) for each applicable customer with the exception of one customer. That exception used 1.86 percent instead of 1.83 percent. We asked MECL to provide installed costs which are a part of the rental charge calculation as well as if there was any reasoning relating to charging 1.86 percent instead of 1.83 percent. Their response is as follows:

> *"Based on a review of the monthly bills for the large industrial customers, there should be a rental charge on line 59 as well. As a result, large industrial forecast revenue is understated by approximately $27.5K per year. This amount is not material given total forecast revenue for the class is $14.3 Million per year and actual revenues will vary from forecast within the class based on the demand and consumption of the customers within this class. The Company considers the total forecast electric revenue of $211.6 million in 2020 and $217.8 million in 2021 reasonable."*

MECL also provided their complete calculations of rental charges for their applicable large industrial customers. The rental charges presented in MECL's Response GT-RFI-2019-61 agree with the rental charges presented in GT-RFI-2019-53. We recalculated the understated revenue as noted in MECL's response above and did not note any exceptions.

As per MECL's approved General Rules and Regulations amendment in UE19-08, the Losses Charge as per N-9 in the GRR, file October 31, 2019, is as follows:

> 69 kV to primary distribution voltage:
>
> At the discretion of Maritime Electric, electricity may be supplied at a primary distribution voltage between 4 kV and 25 kV. In such cases, the monthly demand and energy consumption will be increased by 1½% (1.5%) to compensate for transformation losses.
>
> Primary distribution voltage to Customer's utilization voltage:
>
> At the discretion of Maritime Electric, electricity may be supplied at the Customer's utilization voltage. In such cases, the monthly demand and energy consumption will be increased by 1.5% to compensate for transformation losses. This charge will be in addition to the losses charge for transformation from 69 kV to the primary distribution voltage.

The industrial customers within MECL's energy sales forecasts are charged either Nil%, 1.5%, or 3% for the transformation losses charge to their monthly kW usage. We are unable to verify that their kV to kW transformation aligns with the GRR in N-9 due to customer confidentiality and the customer's specific transformation needs.

14.4. Conclusion

From our analysis we have determined that MECL has appropriately implemented and are currently complying with the amended General Rules and Regulations which were approved in order UE19-08.

Based on our review of the large industrial customers' energy sales and revenue, we did not note any material exceptions and MECL is in accordance with the GRR.

15. Options

15.1. Background

As directed in Commission Order UE 19-11, MECL was required to provide alternatives for the recovery of the Hurricane Dorian operating costs, the use and application of 2019 excess net revenues, and their deferral account balances (i.e. RORA, ECAM and the Weather Normalization). MECL responded to this request with several options/scenarios for the Commission to consider in the January 2020 Filling (Amended II). We acknowledge that MECL has expressed concerns regarding the layering of these options which were prepared in isolation. The user is cautioned that adding two options together may not accurately reflect the final resulting rates. MECL will likely provide an updated rates calculation to the Commission once they have been given direction on the issues under consideration throughout their rate application process.

15.2. Procedures

Our procedures for the prepared options/scenarios by MECL include the following:

- Reviewed the impact on Revenue Requirement, Energy Charge per kWh, and Rate Base in each option for mathematical accuracy, consistency with Application and year over year changes.
- Recalculated customer rate impact as presented by MECL for each option.

15.3. Findings and observations

Below is the list of scenarios prepared by MECL, in addition to the impacts for each option related to the year over year change in Revenue Requirement, a typical customer (rural residential, urban residential, and general service customers) annual cost change, and rate base:

- Options 1A – Dorian Fully Recovered Using 2019 RORA Account;
- Option 1B – Dorian Deferred and Amortized during March 1, 2020 to February 28, 2022;
- Option 2A – Recover CTGS over 24 Months of Rate Setting Period;
- Option 2B – Defer CTGS to the next Rate Setting Period;
- Option 2C – Recover CTGS over 60-month period, CTGS removed from rate base;
- Option 3A – RORA and WNR to Offset ECAM, remaining RORA Refunded over 24 Months;
- Option 3B – RORA and WNR to Offset ECAM, remaining RORA Refunded over 12 Months; and
- Option 3C – RORA to Offset ECAM, remaining RORA Refunded over 24 Months, WNR remain as deferred.

Summary of Impacts						
	Revenue Requirement ($)		Typical Customer Annual Cost % Change		Rate Base ($)	
	2020F - 2019A	2021F - 2020F	2020F - 2019A	2021F - 2020F	2020F - 2019A	2021F - 2020F
Option 1A	18,401,707	1,880,000	1.1%	1.2%	19,361,844	12,432,600
Option 1B	16,737,407	5,091,400	0.5%	2.4%	20,519,444	11,524,900
Option 2A	23,175,307	1,626,200	3.6%	0.6%	14,534,944	7,659,900
Option 2B	18,401,707	1,880,000	1.1%	1.2%	19,361,844	12,432,600
Option 2C	20,310,507	1,804,300	2.1%	0.9%	17,431,244	10,501,500
Option 3A	17,853,207	2,463,200	2.2%	-1.1%	17,284,344	14,410,600
Option 3B	17,845,007	2,467,700	0.9%	1.3%	19,629,444	12,643,100
Option 3C	17,854,107	2,463,900	2.4%	-1.1%	16,866,344	13,877,100

The following sections we completed our procedures on the prepared information for each scenario by MECL.

14.3.1 Option 1 – Dorian Costs

Option 1 is centered around the possible approaches for dealing with the deferral of the Hurricane Dorian Storm Costs which net to $3,002,382. This option has been split into two sub options, Option 1A and Option 1B, both of which are analyzed in further detail below.

14.3.1.1 Option 1A – Dorian Fully Recovered Using 2019 RORA Account

Option 1A proposes using 2019 RORA to recover the costs related to Hurricane Dorian of $3,002,900. The approach of using RORA to recover Dorian costs is the current approach which was outlined in MECL's January 2020 Filling (Amended II). As a result of this option, a typical customer in each rate class would see a 1.1% and 1.2% yearly increase in annual cost in 2020 and 2021, respectively.

Below we have outlined the proposed Revenue Requirement, Energy Charge per kWh, and Rate Base forecasts for 2020 and 2021:

Revenue Requirement

Revenue Requirement ($) - Option 1A	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Operating Expenses (Net of ECAM)*	$ 153,485,663	$ 162,897,200	$ 169,336,300	$ 9,411,537	$ 6,439,100
Interest Expense (including amortization of Debt Issue Costs)	12,901,422	12,844,400	12,854,300	(57,022)	9,900
Amortization - Fixed Assets	23,337,238	28,572,100	26,202,300	5,234,862	(2,369,800)
Amortization - DSM Costs	157,198	127,400	166,600	(29,798)	39,200
Amortization - Lepreau Writedown	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	-	3,002,900	-	3,002,900	(3,002,900)
Income Tax Expense	6,483,242	6,742,200	6,978,200	258,958	236,000
Return on Equity**	14,262,630	14,842,900	15,371,400	580,270	528,500
Total	**$ 210,720,793**	**$ 229,122,500**	**$ 231,002,500**	**$ 18,401,707**	**$ 1,880,000**

* *Excluding Fortis Inc. Costs*

*** Before Disallowable Costs*

As seen above the revenue requirement would increase by $18,401,707 and $1,880,000 in 2020 and 2021 forecast years respectively. These increases are primarily due to the increase in Operating Expenses, Amortization – Fixed Assets, and Amortization – Storm Deferral. Both increases in Operating Expense and Amortization – Fixed Assets are consistent with other options and discussed earlier within our report, in sections, 3.4 and 12.3 respectively. While the change in Amortization – Storm Deferral is a direct result of the plan to use RORA to offset Dorian costs over a 12-month period.

Energy Charge per kWh

Energy Charge per kWh - Revenue Requirement (A) - Option 1A					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Residential - First Block	$ 0.1409	$ 0.1434	$ 0.1429	1.77%	-0.35%
Residential - Second Block	$ 0.1114	$ 0.1134	$ 0.1130	1.80%	-0.35%
General Service - First Block	$ 0.1739	$ 0.1771	$ 0.1765	1.84%	-0.34%
General Service - Second Block	$ 0.1126	$ 0.1147	$ 0.1143	1.87%	-0.35%
Small Industrial - First Block	$ 0.1703	$ 0.1735	$ 0.1729	1.88%	-0.35%
Small Industrial - Second Block	$ 0.0844	$ 0.0860	$ 0.0857	1.90%	-0.35%
Large Industrial	$ 0.0686	$ 0.0701	$ 0.0684	2.19%	-2.43%
Energy Charge per kWh - Other Amounts (B)					
ECAM Charge per kWh	$ 0.0006	$ 0.0020	$ 0.0001	256.10%	-97.47%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0042	$ 0.0041	-20.92%	-3.06%
Provincial Energy Efficiency Program per kWh	$ -	$ 0.0015	$ 0.0008	100.00%	-45.85%
Cable Contingency Fund per kWh	$ 0.0003	$ -	$ -	-100.00%	-100.00%
RORA per kWh	$ (0.0034)	$ (0.0055)	$ -	60.41%	-100.00%
Total Energy Charge per kWh Excluding Basic Revenue	**$ 0.0028**	**$ 0.0023**	**$ 0.0050**	**-17.86%**	**117.39%**
Total Energy Charge per kWh (A+B)					
Residential - First Block	**$ 0.1437**	**$ 0.1457**	**$ 0.1479**	**1.39%**	**1.51%**
Residential - Second Block	**$ 0.1142**	**$ 0.1157**	**$ 0.1180**	**1.31%**	**1.99%**
General Service - First Block	**$ 0.1767**	**$ 0.1794**	**$ 0.1815**	**1.53%**	**1.17%**
General Service - Second Block	**$ 0.1154**	**$ 0.1170**	**$ 0.1193**	**1.39%**	**1.97%**
Small Industrial - First Block	**$ 0.1731**	**$ 0.1758**	**$ 0.1779**	**1.56%**	**1.19%**
Small Industrial - Second Block	**$ 0.0872**	**$ 0.0883**	**$ 0.0907**	**1.26%**	**2.72%**
Large Industrial	**$ 0.0714**	**$ 0.0724**	**$ 0.0734**	**1.40%**	**1.38%**

Option 1A would increase 2020 forecast rates between 1.26 to 1.56 percent and the 2021 forecast rates would increase 1.17 to 2.72 percent compared to 2020 forecast rates.

Rate Base

Calculation of Rate Base ($) - Option 1A					
Components	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Fixed Assets	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 32,447,944	$ (18,546,900)
Less: Capital Work in Progress	(3,750,888)	-	-	3,750,888	-
Less: Accumulated Amortization	(245,078,293)	(269,903,600)	(231,933,900)	(24,825,307)	37,969,700
Less: Contributions in Aid of Construction (net of amortization)	(23,691,857)	(24,598,000)	(25,496,000)	(906,143)	(898,000)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(13,522,753)	(19,754,200)	(26,214,600)	(6,231,447)	(6,460,400)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	2,772,690	72,200	(478,100)	(2,700,490)	(550,300)
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(1,057,328)	-	-	1,057,328	-
Add: Deferred Financing Costs	961,283	947,500	933,000	(13,783)	(14,500)
Add: Intangible Assets	4,002,494	4,150,000	4,300,000	147,506	150,000
Add: Deferred Demand Side Management Costs	127,446	166,600	-	39,154	(166,600)
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,492,744	1,399,400	1,305,900	(93,344)	(93,500)
Add: Regulatory Asset - Storm Deferral	3,002,882	-	-	(3,002,882)	-
Less: Employee Future Benefits Liability	(7,631,568)	(7,711,700)	(7,961,700)	(80,132)	(250,000)
Less (Add): Regulatory Liability OPEB	2,536,000	2,986,600	2,813,800	450,600	(172,800)
Less: Regulatory Liability - Rebates Payable to Customers	(15,453,528)	(5,847,300)	(4,648,100)	9,606,228	1,199,200
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	9,654,500	9,654,500	9,654,500	-
Plus: Working Capital Allowance Comprised of:	-	-	-	-	-
- Inventory	3,240,398	3,000,000	3,000,000	(240,398)	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,508,778	5,852,400	6,098,100	343,622	245,700
Income Taxes Paid X 3.6%	21,000	(21,000)	-	(42,000)	21,000
Total Rate Base	**$ 393,247,356**	**$ 412,609,200**	**$ 425,041,800**	**$ 19,361,844**	**$ 12,432,600**
Average Rate Base	**$ 386,938,159**	**$ 402,928,278**	**$ 418,825,500**	**$ 15,990,119**	**$ 15,897,222**
Actual/Requested Return on Average Rate Base	**7.02%**	**6.87%**	**6.74%**	**-0.15%**	**-0.13%**

Note - Light purple shaded items are related to the scenario's forecasted impacts on select proposed deferral balance treatment.

Based on our analysis of Options 1, 2, and 3 it was noted that there were no differences between any of the options for several forecasted values within the rate base calculation: Fixed Assets, Capital Work in Progress, Contributions in Aid of Construction, Future Income Tax Liability, Deferred Financing Costs, Intangible Assets, Deferred Demand Side Management Costs, Deferred Charge, Employee Future Benefits, Regulatory Liability OPEB, Inventory, Gross Operating Expenses, and Income Taxes. Therefore, within each scenario we will analyze the primary differences related to that particular scenario from actual to forecasted years.

As seen above the rate base for Option 1A increased by $19,361,844 and $12,432,600 in 2020 and 2021 forecasts respectively. Option 1A proposes the use of RORA to offset Dorian costs over the period of 12 months, these changes are forecasted in rate base with storm deferral being reduced to $Nil in the 2020 forecast.

Overall, Option 1A forecasts an increase in revenue requirement, total energy charge per kWh, and total rate base in both 2020 and 2021 forecasts.

14.3.1.2 Option 1B – Dorian Deferred and Amortized during March 1, 2020 to February 28, 2022

Option 1B proposes that the deferral of the Hurricane Dorian storm costs of $3,002,382 is amortized over a 24-month period (March 1, 2020 – February 28, 2022), instead of offsetting the Dorian Deferral cost against the 2019 RORA balance. Therefore, the full amount of the RORA is returned to customers in 2020 forecast year. As a result, a typical customer in each rate class would see a 0.5% and 2.4% yearly increase in annual cost in 2020 and 2021 respectively.

Below we have outlined the proposed Revenue Requirement, Energy Charge per kWh, and Rate Base forecasts for 2020 and 2021:

Revenue Requirement

Revenue Requirement ($) - Option 1B					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Operating Expenses (Net of ECAM)*	$ 153,485,663	$ 162,897,200	$ 169,336,300	$ 9,411,537	$ 6,439,100
Interest Expense (including amortization of Debt Issue Costs)	12,901,422	12,932,200	12,898,300	30,778	(33,900)
Amortization - Fixed Assets	23,337,238	28,572,100	26,202,300	5,234,862	(2,369,800)
Amortization - DSM Costs	157,198	127,400	166,600	(29,798)	39,200
Amortization - Lepreau Writedown	93,400	93,400	93,400	-	-
Amortization - Storm Deferral***	-	1,251,200	1,501,500	1,251,200	250,300
Income Tax Expense	6,483,242	6,742,100	6,978,700	258,858	236,600
Return on Equity**	14,262,630	14,842,600	15,372,500	579,970	529,900
Total	**$ 210,720,793**	**$ 227,458,200**	**$ 232,549,600**	**$ 16,737,407**	**$ 5,091,400**

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

*** *The remaining Dorian balance of $250,200 will be amortized over the final two months of the 24 month rate period, January & February 2022.*

As seen above the revenue requirement would increase by $16,737,407 and $5,091,400 in 2020 and 2021 forecasts respectively.

These increases are primarily due to the increase in Operating Expenses, Amortization – Fixed Assets and Amortization – Storm Deferral. Both increases in Operating Expense and Amortization – Fixed Assets is consistent with other options and discussed earlier within our report, in sections, 3.4 and 12.3 respectively. The forecasted Amortization – Storm Deferral is a direct result of costs being amortized over a period of 24-months instead of offset by RORA.

Energy Charge per kWh

Energy Charge per kWh - Revenue Requirement (A) - Option 1B					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Residential - First Block	$ 0.1409	$ 0.1446	$ 0.1441	2.63%	-0.35%
Residential - Second Block	$ 0.1114	$ 0.1143	$ 0.1139	2.60%	-0.35%
General Service - First Block	$ 0.1739	$ 0.1784	$ 0.1780	2.59%	-0.22%
General Service - Second Block	$ 0.1126	$ 0.1155	$ 0.1153	2.58%	-0.17%
Small Industrial - First Block	$ 0.1703	$ 0.1747	$ 0.1744	2.58%	-0.17%
Small Industrial - Second Block	$ 0.0844	$ 0.0866	$ 0.0864	2.61%	-0.23%
Large Industrial	$ 0.0686	$ 0.0718	$ 0.0690	4.66%	-3.90%
Energy Charges per kWh - Other Amounts (B)					
ECAM Charge per kWh	$ 0.0006	$ 0.0020	$ 0.0001	256.10%	-97.47%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0042	$ 0.0041	-20.92%	-3.06%
Provincial Energy Efficiency Program per kWh	$ -	$ 0.0015	$ 0.0008	100.00%	-45.85%
Cable Contingency Fund per kWh	$ 0.0003	$ -	$ -	-100.00%	0.00%
RORA per kWh	$ (0.0034)	$ (0.0077)	$ -	124.78%	-100.00%
Total Energy Charge per kWh Excluding Basic Revenue	**$ 0.0028**	**$ -**	**$ 0.0050**	**-100.00%**	**100.00%**
Total Energy Charge per kWh (A+B)					
Residential - First Block	**$ 0.1437**	**$ 0.1446**	**$ 0.1491**	**0.63%**	**3.11%**
Residential - Second Block	**$ 0.1142**	**$ 0.1143**	**$ 0.1189**	**0.09%**	**4.02%**
General Service - First Block	**$ 0.1767**	**$ 0.1784**	**$ 0.1830**	**0.96%**	**2.58%**
General Service - Second Block	**$ 0.1154**	**$ 0.1155**	**$ 0.1203**	**0.09%**	**4.16%**
Small Industrial - First Block	**$ 0.1731**	**$ 0.1747**	**$ 0.1794**	**0.92%**	**2.69%**
Small Industrial - Second Block	**$ 0.0872**	**$ 0.0866**	**$ 0.0914**	**-0.69%**	**5.54%**
Large Industrial	**$ 0.0714**	**$ 0.0718**	**$ 0.0740**	**0.56%**	**3.06%**

Option 1B would increase 2020 forecast rates between 0.09 to 0.96 percent, with one outlier being Small Industrial – Second Block, which would decrease by 0.69 percent. The 2021 forecast rates would increase between 2.69 to 5.54 percent compared to 2020 forecast rates.

Rate Base

Calculation of Rate Base ($) - Option 1B					
Components	**2019A**	**2020F**	**2021F**	**2020F - 2019A**	**2021F - 2020F**
Fixed Assets	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 32,447,944	$ (18,546,900)
Less: Capital Work in Progress	(3,750,888)	-	-	3,750,888	-
Less: Accumulated Amortization	(245,078,293)	(269,903,600)	(231,933,900)	(24,825,307)	37,969,700
Less: Contributions in Aid of Construction (net of amortization)	(23,691,857)	(24,598,000)	(25,496,000)	(906,143)	(898,000)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(13,522,753)	(19,754,000)	(26,215,000)	(6,231,247)	(6,461,000)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	2,772,690	72,200	(478,100)	(2,700,490)	(550,300)
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(1,057,328)	-	-	1,057,328	-
Add: Deferred Financing Costs	961,283	947,500	933,000	(13,783)	(14,500)
Add: Intangible Assets	4,002,494	4,150,000	4,300,000	147,506	150,000
Add: Deferred Demand Side Management Costs	127,446	166,600	-	39,154	(166,600)
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,492,744	1,399,400	1,306,000	(93,344)	(93,400)
Add: Regulatory Asset - Storm Deferral	3,002,882	1,751,700	250,200	(1,251,182)	(1,501,500)
Less: Employee Future Benefits Liability	(7,631,568)	(7,711,700)	(7,961,700)	(80,132)	(250,000)
Less (Add): Regulatory Liability OPEB	2,536,000	2,986,600	2,813,800	450,600	(172,800)
Less: Regulatory Liability - Rebates Payable to Customers	(15,453,528)	(6,441,600)	(4,648,100)	9,011,928	1,793,500
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	9,654,500	9,654,500	9,654,500	-
Plus: Working Capital Allowance Comprised of:	-	-	-	-	-
- Inventory	3,240,398	3,000,000	3,000,000	(240,398)	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,508,778	5,852,400	6,098,100	343,622	245,700
Income Taxes Paid X 3.6%	21,000	(21,000)	-	(42,000)	21,000
Total Rate Base	**$ 393,247,356**	**$ 413,766,800**	**$ 425,291,700**	**$ 20,519,444**	**$ 11,524,900**
Average Rate Base	**$ 386,938,159**	**$ 403,507,078**	**$ 419,529,300**	**$ 16,568,919**	**$ 16,022,222**
Actual/Requested Return on Average Rate Base	**7.02%**	**6.88%**	**6.74%**	**-0.14%**	**-0.14%**

Note - Light purple shaded items are related to the scenario's forecasted impacts on select proposed deferral balance treatment.

As seen above the rate base for Option 1B increases by $20,519,444 and $11,524,900 in 2020 and 2021 respectively.

The primary differences are related to the treatment of the storm deferral balance, which is the basis of the option presented. Option 1B proposes that Dorian costs are amortized over the 24-month period, these changes are forecasted in rate base with storm deferral being reduced to $1,751,700 in the 2020 forecast and to $250,200 in the 2021 forecast. Additionally, rebates payable to customers would be affected as RORA does not offset Dorian costs.

Overall, Option 1B forecasts an increase in revenue requirement, total energy charge per kWh, and total rate base in both 2020 and 2021 forecasts.

14.3.2 Option 2 - CTGS

Option 2 is based on the accumulated reserve variance of $9,654,600 being removed from the rate base. The removal of the accumulated reserve variance from rate base would have no impact on assets or rate base as this deferral account is an accounting balance sheet entry only. Option 2 has been split into three sub options, Option 2A, Option 2B, and Option 2C, all three of which are analyzed in further detail below.

14.3.2.1 Option 2A – Recover CTGS over 24 Months of Rate Setting Period

Option 2A, proposes recovering the CTGS accumulated reserve over a 24-month period (March 1, 2020 to February 28, 2022). The depreciation charges in 2020 and 2021 forecasts are increased to recover the full cost of the CTGS, including decommissioning costs net of salvage prior to decommissioning at the end of 2021. As a result, a typical customer in each rate class would see a 3.6% and 0.6% yearly increase in annual cost in 2020 and 2021, respectively.

Below we have outlined the Option 2A Revenue Requirement, Energy Charge per kWh, and Rate Base forecasts for 2020 and 2021:

Revenue Requirement

Revenue Requirement ($) - Option 2A					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Operating Expenses (Net of ECAM)*	$ 153,485,663	$ 162,897,200	$ 169,336,300	$ 9,411,537	$ 6,439,100
Interest Expense (including amortization of Debt Issue Costs)	12,901,422	12,791,700	12,723,000	(109,722)	(68,700)
Amortization - Fixed Assets	23,337,238	33,399,400	31,029,600	10,062,162	(2,369,800)
Amortization - DSM Costs	157,198	127,400	166,600	(29,798)	39,200
Amortization - Lepreau Writedown	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	-	3,002,900	-	3,002,900	(3,002,900)
Income Tax Expense	6,483,242	6,741,900	6,923,600	258,658	181,700
Return on Equity**	14,262,630	14,842,200	15,249,800	579,570	407,600
Total	**$ 210,720,793**	**$ 233,896,100**	**$ 235,522,300**	**$ 23,175,307**	**$ 1,626,200**

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

As seen above revenue requirement would increase by $23,175,307 and $1,626,200 for the 2020 and 2021 forecast years respectively. These increases are primarily due to the increase in Operating Expenses, Amortization – Fixed Assets, and Amortization – Storm Deferral. The increase in Operating Expense and Amortization – Storm Deferral is consistent with other options and discussed earlier within our report. The forecasted Amortization – Fixed Assets is a direct result of the proposed option to increase depreciation to recover the full cost of the CTGS.

Energy Charge per kWh

Energy Charge per kWh - Revenue Requirement (A) - Option 2A					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Residential - First Block	$ 0.1409	$ 0.1480	$ 0.1464	5.04%	-1.08%
Residential - Second Block	$ 0.1114	$ 0.1170	$ 0.1157	5.03%	-1.11%
General Service - First Block	$ 0.1739	$ 0.1827	$ 0.1808	5.06%	-1.04%
General Service - Second Block	$ 0.1126	$ 0.1183	$ 0.1171	5.06%	-1.01%
Small Industrial - First Block	$ 0.1703	$ 0.1789	$ 0.1770	5.05%	-1.06%
Small Industrial - Second Block	$ 0.0844	$ 0.0887	$ 0.0878	5.09%	-1.01%
Large Industrial	$ 0.0686	$ 0.0723	$ 0.0701	5.39%	-3.04%
Energy Charges per kWh - Other Amounts (B)					
ECAM Charge per kWh	$ 0.0006	$ 0.0020	$ 0.0001	256.10%	-97.47%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0042	$ 0.0041	-20.92%	-3.06%
Provincial Energy Efficiency Program per kWh	$ -	$ 0.0015	$ 0.0008	100.00%	-45.85%
Cable Contingency Fund per kWh	$ 0.0003	$ -	$ -	-100.00%	0.00%
RORA per kWh	$ (0.0034)	$ (0.0055)	$ -	60.41%	-100.00%
Total Energy Charge per kWh Excluding Basic Revenue	**$ 0.0028**	**$ 0.0023**	**$ 0.0050**	**-17.86%**	**117.39%**
Total Energy Charge per kWh (A+B)					
Residential - First Block	**$ 0.1437**	**$ 0.1503**	**$ 0.1514**	**4.59%**	**0.73%**
Residential - Second Block	**$ 0.1142**	**$ 0.1193**	**$ 0.1207**	**4.47%**	**1.17%**
General Service - First Block	**$ 0.1767**	**$ 0.1850**	**$ 0.1858**	**4.70%**	**0.43%**
General Service - Second Block	**$ 0.1154**	**$ 0.1206**	**$ 0.1221**	**4.51%**	**1.24%**
Small Industrial - First Block	**$ 0.1731**	**$ 0.1812**	**$ 0.1820**	**4.68%**	**0.44%**
Small Industrial - Second Block	**$ 0.0872**	**$ 0.0910**	**$ 0.0928**	**4.36%**	**1.98%**
Large Industrial	**$ 0.0714**	**$ 0.0746**	**$ 0.0751**	**4.48%**	**0.67%**

Option 2A would increase 2020 forecast rates between 4.36 to 4.70 percent and the 2021 forecast rates would increase 0.43 to 1.98 percent compared to 2020 forecast rates.

Rate Base

Calculation of Rate Base ($) - Option 2A					
Components	**2019A**	**2020F**	**2021F**	**2020F - 2019A**	**2021F - 2020F**
Fixed Assets	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 32,447,944	$ (18,546,900)
Less: Capital Work in Progress	(3,750,888)	-	-	3,750,888	-
Less: Accumulated Amortization	(245,078,293)	(265,076,400)	(231,933,900)	(19,998,107)	33,142,500
Less: Contributions in Aid of Construction (net of amortization)	(23,691,857)	(24,598,000)	(25,496,000)	(906,143)	(898,000)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(13,522,753)	(19,753,800)	(26,159,700)	(6,231,047)	(6,405,900)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	2,772,690	72,200	(478,100)	(2,700,490)	(550,300)
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(1,057,328)	-	-	1,057,328	-
Add: Deferred Financing Costs	961,283	947,500	933,000	(13,783)	(14,500)
Add: Intangible Assets	4,002,494	4,150,000	4,300,000	147,506	150,000
Add: Deferred Demand Side Management Costs	127,446	166,600	-	39,154	(166,600)
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,492,744	1,399,400	1,305,900	(93,344)	(93,500)
Add: Regulatory Asset - Storm Deferral	3,002,882	-	-	(3,002,882)	-
Less: Employee Future Benefits Liability	(7,631,568)	(7,711,700)	(7,961,700)	(80,132)	(250,000)
Less (Add): Regulatory Liability OPEB	2,536,000	2,986,600	2,813,800	450,600	(172,800)
Less: Regulatory Liability - Rebates Payable to Customers	(15,453,528)	(5,847,300)	(4,648,100)	9,606,228	1,199,200
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	-	-	-
Plus: Working Capital Allowance Comprised of:	-	-	-	-	-
- Inventory	3,240,398	3,000,000	3,000,000	(240,398)	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,508,778	5,852,400	6,098,100	343,622	245,700
Income Taxes Paid X 3.6%	21,000	(21,000)	-	(42,000)	21,000
Total Rate Base	**$ 393,247,356**	**$ 407,782,300**	**$ 415,442,200**	**$ 14,534,944**	**$ 7,659,900**
Average Rate Base	**$ 386,938,159**	**$ 400,514,800**	**$ 411,612,300**	**$ 13,576,641**	**$ 11,097,500**
Actual/Requested Return on Average Rate Base	**7.02%**	**6.90%**	**6.79%**	**-0.12%**	**-0.10%**

Note - Light purple shaded items are related to the scenario's forecasted impacts on select proposed deferral balance treatment.

As seen above the rate base for Option 2A increases by $14,534,944 and $7,659,900 in 2020 and 2021 respectively. The primary differences from actual to forecast within the table above are related to the CTGS accumulated reserve variance and the accumulated amortization, which is the basis of the option presented. Option 2A proposes the increase of depreciation to recover the full cost of the CTGS over a period of 24-months. These changes are mirrored in the forecasted Rate Base with the balance of CTGS being reduced to $Nil.

Overall, Option 2A forecasts an increase in revenue requirement, total energy charge per kWh, and total rate base in both 2020 and 2021 forecasts.

14.3.2.2 Option 2B – Defer CTGS to the next Rate Setting Period

Option 2B proposes the use of 2017 depreciation rates and defer the CTGS to next rate setting period.

This option has the same results as Option 1A discussed previously. The only difference is that instead of recognizing the estimated shortfall of $9,654,500 to be recovered from customers as a regulated deferral account, the proposed deferral is removed from Rate Base, as well as a corresponding offset to accumulated depreciation of the same amount. As discussed previously, the removal of the CTGS from rate base would have no impact on rates as this deferral account is an accounting balance sheet entry only.

14.3.2.3 Option 2C – Recover CTGS over 60-month period, CGTS removed from rate base

Option 2C proposes amortizing the CTGS accumulated Reserve costs of $9,654,500 over a 60-month period ($1,930,900 per year) beginning March 1, 2020. As a result, a typical customer in each rate class would see a 2.1% and 0.9% yearly increase in annual cost in 2020 and 2021 respectively.

Below we have outlined the proposed Revenue Requirement, Energy Charge per kWh, and Rate Base forecasts for 2020 and 2021:

Revenue Requirement

Revenue Requirement ($) - Option 2C					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Operating Expenses (Net of ECAM)*	$ 153,485,663	$ 162,897,200	$ 169,336,300	$ 9,411,537	$ 6,439,100
Interest Expense (including amortization of Debt Issue Costs)	12,901,422	12,823,300	12,755,900	(78,122)	(67,400)
Amortization - Fixed Assets	23,337,238	30,503,000	28,133,200	7,165,762	(2,369,800)
Amortization - DSM Costs	157,198	127,400	166,600	(29,798)	39,200
Amortization - Lepreau Writedown	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	-	3,002,900	-	3,002,900	(3,002,900)
Income Tax Expense	6,483,242	6,741,900	6,978,400	258,658	236,500
Return on Equity**	14,262,630	14,842,200	15,371,800	579,570	529,600
Total	**$ 210,720,793**	**$ 231,031,300**	**$ 232,835,600**	**$ 20,310,507**	**$ 1,804,300**

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

As seen above revenue requirement would increase by $20,310,507 and $1,804,300 for 2020 and 2021 forecast years respectively. These increases are primarily due to the increase in Operating Expenses, Amortization – Fixed Assets, and Amortization – Storm Deferral. The increase in Operating Expense and Amortization – Storm Deferral is consistent with other options as discussed above. The change in Amortization – Fixed Assets is a direct result of the proposed option to amortize the CTGS accumulated Reserve of $9,654,500 ($1,930,900 per year) over a 60-month period.

Energy Charge per kWh

Energy Charge per kWh - Revenue Requirement (A) - Option 2C					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Residential - First Block	$ 0.1409	$ 0.1453	$ 0.1443	3.12%	-0.69%
Residential - Second Block	$ 0.1114	$ 0.1149	$ 0.1141	3.14%	-0.70%
General Service - First Block	$ 0.1739	$ 0.1793	$ 0.1782	3.11%	-0.61%
General Service - Second Block	$ 0.1126	$ 0.1161	$ 0.1154	3.11%	-0.60%
Small Industrial - First Block	$ 0.1703	$ 0.1756	$ 0.1745	3.11%	-0.63%
Small Industrial - Second Block	$ 0.0844	$ 0.0870	$ 0.0865	3.08%	-0.57%
Large Industrial	$ 0.0686	$ 0.0709	$ 0.0690	3.35%	-2.68%
Energy Charges per kWh - Other Amounts (B)					
ECAM Charge per kWh	$ 0.0006	$ 0.0020	$ 0.0001	256.10%	-97.47%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0042	$ 0.0041	-20.92%	-3.06%
Provincial Energy Efficiency Program per kWh	$ -	$ 0.0015	$ 0.0008	100.00%	-45.85%
Cable Contingency Fund per kWh	$ 0.0003	$ -	$ -	-100.00%	0.00%
RORA per kWh	$ (0.0034)	$ (0.0055)	$ -	60.41%	-100.00%
Total Energy Charge per kWh Excluding Basic Revenue	**$ 0.0028**	**$ 0.0023**	**$ 0.0050**	**-17.86%**	**117.39%**
Total Energy Charge per kWh (A+B)					
Residential - First Block	**$ 0.1437**	**$ 0.1476**	**$ 0.1493**	**2.71%**	**1.15%**
Residential - Second Block	**$ 0.1142**	**$ 0.1172**	**$ 0.1191**	**2.63%**	**1.62%**
General Service - First Block	**$ 0.1767**	**$ 0.1816**	**$ 0.1832**	**2.77%**	**0.88%**
General Service - Second Block	**$ 0.1154**	**$ 0.1184**	**$ 0.1204**	**2.60%**	**1.69%**
Small Industrial - First Block	**$ 0.1731**	**$ 0.1779**	**$ 0.1795**	**2.77%**	**0.90%**
Small Industrial - Second Block	**$ 0.0872**	**$ 0.0893**	**$ 0.0915**	**2.41%**	**2.46%**
Large Industrial	**$ 0.0714**	**$ 0.0732**	**$ 0.0740**	**2.52%**	**1.09%**

Option 2C would increase 2020 forecast rates between 2.41 to 2.77 percent and the 2021 forecast rates would increase between 0.88 to 2.46 percent compared to 2020 forecast rates.

Rate Base

Calculation of Rate Base ($) - Option 2C					
Components	**2019A**	**2020F**	**2021F**	**2020F - 2019A**	**2021F - 2020F**
Fixed Assets	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 32,447,944	$ (18,546,900)
Less: Capital Work in Progress	(3,750,888)	-	-	3,750,888	-
Less: Accumulated Amortization	(245,078,293)	(262,180,000)	(226,141,200)	(17,101,707)	36,038,800
Less: Contributions in Aid of Construction (net of amortization)	(23,691,857)	(24,598,000)	(25,496,000)	(906,143)	(898,000)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(13,522,753)	(19,753,900)	(26,214,500)	(6,231,147)	(6,460,600)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	2,772,690	72,200	(478,100)	(2,700,490)	(550,300)
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(1,057,328)	-	-	1,057,328	-
Add: Deferred Financing Costs	961,283	947,500	933,000	(13,783)	(14,500)
Add: Intangible Assets	4,002,494	4,150,000	4,300,000	147,506	150,000
Add: Deferred Demand Side Management Costs	127,446	166,600	-	39,154	(166,600)
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,492,744	1,399,400	1,305,900	(93,344)	(93,500)
Add: Regulatory Asset - Storm Deferral	3,002,882	-	-	(3,002,882)	-
Less: Employee Future Benefits Liability	(7,631,568)	(7,711,700)	(7,961,700)	(80,132)	(250,000)
Less (Add): Regulatory Liability OPEB	2,536,000	2,986,600	2,813,800	450,600	(172,800)
Less: Regulatory Liability - Rebates Payable to Customers	(15,453,528)	(5,847,300)	(4,648,100)	9,606,228	1,199,200
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	-	-	-	-
Plus: Working Capital Allowance Comprised of:	-	-	-	-	-
- Inventory	3,240,398	3,000,000	3,000,000	(240,398)	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,508,778	5,852,400	6,098,100	343,622	245,700
Income Taxes Paid X 3.6%	21,000	(21,000)	-	(42,000)	21,000
Total Rate Base	**$ 393,247,356**	**$ 410,678,600**	**$ 421,180,100**	**$ 17,431,244**	**$ 10,501,500**
Average Rate Base	**$ 386,938,159**	**$ 401,963,000**	**$ 415,929,400**	**$ 15,024,841**	**$ 13,966,400**
Actual/Requested Return on Average Rate Base	**7.02%**	**6.88%**	**6.76%**	**-0.14%**	**-0.12%**

Note - Light purple shaded items are related to the scenario's forecasted impacts on select proposed deferral balance treatment.

As seen above the rate base for Option 2C increases by $17,431,244 and $10,501,500 in 2020 and 2021 respectively. The primary differences relate to the treatment CTGS accumulated reserve variance, which is the basis of the option presented. Option 2C proposes the amortization of the CTGS accumulated reserve over a period of 60-months and removal of the CTGS from rate base. These changes are forecasted in rate base with the balance of CTGS being reduced to $Nil, with the offsetting entry reflected in accumulated depreciation less the additional amounts recovered through depreciation (2020 – $1.93million and 2021 – 1.93M X 2 years = $3.86million).

Overall, Option 2C forecasts an increase in revenue requirement, total energy charge per kWh, and total rate base in both 2020 and 2021 forecasts.

14.3.3 Option 3 – Deferral Accounts

In each of the option presented below , ECAM base rate as proposed in Section 4.1 of the January 2020 Filling (Amended II). ECAM base rates would decrease from $0.09225 per kWh to $0.09185 per kWh effective March 1, 2020 and increase from $0.09244 per kWh to $0.09258 per kWh on March 1, 2021. Furthermore, according to MECL this adjustment is required to ensure that the annual energy costs are included in revenue requirement and charged to customers in the year incurred to reflect the forecast actual energy costs for the year, in turn not deferred to the ECAM account at the end of each year. Option 3 has been split into three sub options, Option 3A, Option 3B, and Option 3C, which are analyzed in detail below.

14.3.3.1 Option 3A – RORA and WNR to Offset ECAM, remaining RORA Refunded over 24 Months

Option 3A proposes the use of RORA and WNR to offset ECAM balances. In this option, the Weather Normalization balance at December 31, 2019 of $1,057,328 is applied directly to the December 31, 2019 ECAM balance of $2,772,686. The remaining ECAM balance of $1,715,358 is offset by the RORA balance such that the net RORA amount to be refunded to customers is reduced from $7,483,659 to $5,768,301. This new RORA balance would then be refunded at a rate of $0.0021 per kWh over the 24-month period commencing March 1, 2020 (based on forecast sales of 2,745,585,553 kWh from March 1, 2020 to February 28, 2022). As a result, a typical customer in each rate class would see a 2.2% increase in annual cost in 2020 and 1.1% decrease in annual cost in 2021.

Below we have outlined the proposed Revenue Requirement, Energy Charge per kWh, and Rate Base forecasts for 2020 and 2021:

Revenue Requirement

Revenue Requirement ($) - Option 3A	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Operating Expenses (Net of ECAM)*	$ 153,485,663	$ 162,420,600	$ 169,392,700	$ 8,934,937	$ 6,972,100
Interest Expense (including amortization of Debt Issue Costs)	12,901,422	12,772,800	12,831,400	(128,622)	58,600
Amortization - Fixed Assets	23,337,238	28,572,100	26,202,300	5,234,862	(2,369,800)
Amortization - DSM Costs	157,198	127,400	166,600	(29,798)	39,200
Amortization - Lepreau Writedown	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	-	3,002,900	-	3,002,900	(3,002,900)
Income Tax Expense	6,483,242	6,742,100	6,978,600	258,858	236,500
Return on Equity**	14,262,630	14,842,700	15,372,200	580,070	529,500
Total	**$ 210,720,793**	**$ 228,574,000**	**$ 231,037,200**	**$ 17,853,207**	**$ 2,463,200**

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

As seen above revenue requirement would increase by $17,853,207 and $2,643,200 in 2020 and 2021 forecast years respectively. These increases are primarily due to the increase in Operating Expenses, Amortization – Fixed Assets, and Amortization – Storm Deferral. The increase in Amortization – Fixed Assets and Amortization – Storm Deferral are consistent with other options and discussed earlier within our report. The changes in Operating Expense is a direct result of the plan to use RORA and WNR to offset ECAM balances.

Energy Charge per kWh

Energy Charge per kWh - Revenue Requirement (A) - Option 3A					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Residential - First Block	$ 0.1409	$ 0.1441	$ 0.1428	2.27%	-0.90%
Residential - Second Block	$ 0.1114	$ 0.1139	$ 0.1129	2.24%	-0.88%
General Service - First Block	$ 0.1739	$ 0.1778	$ 0.1762	2.24%	-0.90%
General Service - Second Block	$ 0.1126	$ 0.1151	$ 0.1141	2.22%	-0.87%
Small Industrial - First Block	$ 0.1703	$ 0.1741	$ 0.1725	2.23%	-0.92%
Small Industrial - Second Block	$ 0.0844	$ 0.0863	$ 0.0855	2.25%	-0.93%
Large Industrial	$ 0.0686	$ 0.0697	$ 0.0695	1.60%	-0.29%
Energy Charges per kWh - Other Amounts (B)					
ECAM Charge per kWh	$ 0.0006	$ (0.0000)	$ (0.0000)	-100.00%	916.43%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0042	$ 0.0041	-20.92%	-3.06%
Provincial Energy Efficiency Program per kWh	$ -	$ 0.0015	$ 0.0008	100.00%	-45.85%
Cable Contingency Fund per kWh	$ 0.0003	$ -	$ -	-100.00%	0.00%
RORA per kWh	$ (0.0034)	$ (0.0021)	$ (0.0021)	-39.02%	0.00%
Total Energy Charge per kWh Excluding Basic Revenue	**$ 0.0028**	**$ 0.0036**	**$ 0.0028**	**29.92%**	**-22.47%**
Total Energy Charge per kWh (A+B)					
Residential - First Block	**$ 0.1437**	**$ 0.1477**	**$ 0.1456**	**2.81%**	**-1.43%**
Residential - Second Block	**$ 0.1142**	**$ 0.1175**	**$ 0.1157**	**2.92%**	**-1.55%**
General Service - First Block	**$ 0.1767**	**$ 0.1814**	**$ 0.1790**	**2.68%**	**-1.33%**
General Service - Second Block	**$ 0.1154**	**$ 0.1187**	**$ 0.1169**	**2.89%**	**-1.53%**
Small Industrial - First Block	**$ 0.1731**	**$ 0.1777**	**$ 0.1753**	**2.68%**	**-1.36%**
Small Industrial - Second Block	**$ 0.0872**	**$ 0.0899**	**$ 0.0883**	**3.14%**	**-1.80%**
Large Industrial	**$ 0.0714**	**$ 0.0733**	**$ 0.0723**	**2.71%**	**-1.39%**

Option 3A would increase 2020 forecast rates between 2.68 to 3.14 percent and the 2021 forecast rates would decrease between 1.33 to 1.80 percent compared to 2020 forecast rates.

Rate Base

Calculation of Rate Base ($) - Option 3A					
Components	**2019A**	**2020F**	**2021F**	**2020F - 2019A**	**2021F - 2020F**
Fixed Assets	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 32,447,944	$ (18,546,900)
Less: Capital Work in Progress	(3,750,888)	-	-	3,750,888	-
Less: Accumulated Amortization	(245,078,293)	(269,903,600)	(231,933,900)	(24,825,307)	37,969,700
Less: Contributions in Aid of Construction (net of amortization)	(23,691,857)	(24,598,000)	(25,496,000)	(906,143)	(898,000)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(13,522,753)	(19,754,200)	(26,214,600)	(6,231,447)	(6,460,400)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	2,772,690	-	-	(2,772,690)	-
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(1,057,328)	-	-	1,057,328	-
Add: Deferred Financing Costs	961,283	947,500	933,000	(13,783)	(14,500)
Add: Intangible Assets	4,002,494	4,150,000	4,300,000	147,506	150,000
Add: Deferred Demand Side Management Costs	127,446	166,600	-	39,154	(166,600)
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,492,744	1,399,400	1,305,900	(93,344)	(93,500)
Add: Regulatory Asset - Storm Deferral	3,002,882	-	-	(3,002,882)	-
Less: Employee Future Benefits Liability	(7,631,568)	(7,711,700)	(7,961,700)	(80,132)	(250,000)
Less (Add): Regulatory Liability OPEB	2,536,000	2,986,600	2,813,800	450,600	(172,800)
Less: Regulatory Liability - Rebates Payable to Customers	(15,453,528)	(7,852,600)	(5,225,700)	7,600,928	2,626,900
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	9,654,500	9,654,500	9,654,500	-
Plus: Working Capital Allowance Comprised of:	-	-	-	-	-
- Inventory	3,240,398	3,000,000	3,000,000	(240,398)	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,508,778	5,852,400	6,098,100	343,622	245,700
Income Taxes Paid X 3.6%	21,000	(21,000)	-	(42,000)	21,000
Total Rate Base	**$ 393,247,356**	**$ 410,531,700**	**$ 424,942,300**	**$ 17,284,344**	**$ 14,410,600**
Average Rate Base	**$ 386,938,159**	**$ 401,889,528**	**$ 417,737,000**	**$ 14,951,369**	**$ 15,847,472**
Actual/Requested Return on Average Rate Base	**7.02%**	**6.87%**	**6.75%**	**-0.15%**	**-0.12%**

Note - Light purple shaded items are related to the scenario's forecasted impacts on select proposed deferral balance treatment.

As seen above the rate base for Option 3A increases by $17,284,344 and $14,410,600 in 2020 and 2021 respectively. These increases are primarily related the costs payable to (recoverable from) customers post 2003 balance and the regulatory liability – rebates payable to customers balance. Option 3A proposes the use of RORA and WNR to offset ECAM balances, with any remaining RORA balance being refunded over a period of 24-months, these changes are forecasted in rate base with Costs payable to (recoverable from) customers post 2003 being reduced to $Nil and an adjustment to rebates payable to customers.

Overall, Option 3A forecasts an increase in revenue requirement and total rate base in both 2020 and 2021 forecasts. Additionally, the energy charge per kWh would increase in 2020 and decrease in 2021.

14.3.3.2 Option 3B – RORA and WNR to Offset ECAM, remaining RORA Refunded over 12-Months

Option 3B proposes the use of RORA and WNR to offset ECAM balances with any remaining RORA balance being refunded over a period of 12-months starting March 31, 2020. In this option, the Weather Normalization balance at December 31, 2019 of $1,057,328 is applied directly to the December 31, 2019 ECAM balance of $2,772,686. The remaining ECAM balance of $1,715,358 is offset by the RORA balance such that the net RORA amount to be refunded to customers is reduced from $7,483,659 to $5,768,301. This new RORA balance would then be refunded at a rate of $0.0043 per kWh over the 12-month period commencing March 1, 2020 (based on forecast sales of 1,354,147,389 kWh from March 1, 2020 to February 28, 2021). As a result, a typical customer in each rate class would see a 0.9% and 1.3% yearly increase in annual cost in 2020 and 2021, respectively.

Below we have outlined the proposed Revenue Requirement, Energy Charge per kWh, and Rate Base forecasts for 2020 and 2021:

Revenue Requirement

Revenue Requirement ($) - Option 3B					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Operating Expenses (Net of ECAM)*	$ 153,485,663	$ 162,420,600	$ 169,392,700	$ 8,934,937	$ 6,972,100
Interest Expense (including amortization of Debt Issue Costs)	12,901,422	12,765,000	12,828,100	(136,422)	63,100
Amortization - Fixed Assets	23,337,238	28,572,100	26,202,300	5,234,862	(2,369,800)
Amortization - DSM Costs	157,198	127,400	166,600	(29,798)	39,200
Amortization - Lepreau Writedown	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	-	3,002,900	-	3,002,900	(3,002,900)
Income Tax Expense	6,483,242	6,742,000	6,978,500	258,758	236,500
Return on Equity**	14,262,630	14,842,400	15,371,900	579,770	529,500
Total	**$ 210,720,793**	**$ 228,565,800**	**$ 231,033,500**	**$ 17,845,007**	**$ 2,467,700**

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

As seen above revenue requirement would increase by $17,845,007 and $2,467,700 in 2020 and 2021 forecast years respectively. These increases are primarily due to the increase in Operating Expenses, Amortization – Fixed Assets. The increase in Amortization – Fixed Assets and Amortization – Storm Deferral are consistent with other options discussed earlier within our report. The change in Operating Expense is a direct result of the plan to use RORA and WNR to offset ECAM balances.

Energy Charge per kWh

Energy Charge per kWh - Revenue Requirement (A) - Option 3B					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Residential - First Block	$ 0.1409	$ 0.1439	$ 0.1429	2.13%	-0.69%
Residential - Second Block	$ 0.1114	$ 0.1137	$ 0.1129	2.06%	-0.70%
General Service - First Block	$ 0.1739	$ 0.1776	$ 0.1764	2.13%	-0.68%
General Service - Second Block	$ 0.1126	$ 0.1150	$ 0.1142	2.13%	-0.70%
Small Industrial - First Block	$ 0.1703	$ 0.1740	$ 0.1728	2.17%	-0.69%
Small Industrial - Second Block	$ 0.0844	$ 0.0862	$ 0.0856	2.13%	-0.70%
Large Industrial	$ 0.0686	$ 0.0707	$ 0.0684	3.06%	-3.25%
Energy Charges per kWh - Other Amounts (B)					
ECAM Charge per kWh	$ 0.0006	$ (0.0000)	$ (0.0000)	-100.00%	916.43%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0042	$ 0.0041	-20.92%	-3.06%
Provincial Energy Efficiency Program per kWh	$ -	$ 0.0015	$ 0.0008	100.00%	-45.85%
Cable Contingency Fund per kWh	$ 0.0003	$ -	$ -	-100.00%	0.00%
RORA per kWh	$ (0.0034)	$ (0.0043)	$ -	23.64%	-100.00%
Total Energy Charge per kWh Excluding Basic Revenue	**$ 0.0028**	**$ 0.0015**	**$ 0.0049**	**-47.18%**	**232.76%**
Total Energy Charge per kWh (A+B)					
Residential - First Block	**$ 0.1437**	**$ 0.1454**	**$ 0.1478**	**1.17%**	**1.68%**
Residential - Second Block	**$ 0.1142**	**$ 0.1152**	**$ 0.1178**	**0.86%**	**2.29%**
General Service - First Block	**$ 0.1767**	**$ 0.1791**	**$ 0.1813**	**1.35%**	**1.25%**
General Service - Second Block	**$ 0.1154**	**$ 0.1165**	**$ 0.1191**	**0.94%**	**2.27%**
Small Industrial - First Block	**$ 0.1731**	**$ 0.1755**	**$ 0.1777**	**1.37%**	**1.28%**
Small Industrial - Second Block	**$ 0.0872**	**$ 0.0877**	**$ 0.0905**	**0.55%**	**3.24%**
Large Industrial	**$ 0.0714**	**$ 0.0722**	**$ 0.0733**	**1.09%**	**1.58%**

Option 3B would allow for an increase in 2020 forecast rates between 0.55 to 1.37 percent and the 2021 forecast rates increase between 1.28 to 3.24 percent compared to 2020 forecast rates.

Rate Base

Calculation of Rate Base ($) - Option 3B					
Components	**2019A**	**2020F**	**2021F**	**2020F - 2019A**	**2021F - 2020F**
Fixed Assets	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 32,447,944	$ (18,546,900)
Less: Capital Work in Progress	(3,750,888)	-	-	3,750,888	-
Less: Accumulated Amortization	(245,078,293)	(269,903,600)	(231,933,900)	(24,825,307)	37,969,700
Less: Contributions in Aid of Construction (net of amortization)	(23,691,857)	(24,598,000)	(25,496,000)	(906,143)	(898,000)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(13,522,753)	(19,753,900)	(26,214,600)	(6,231,147)	(6,460,700)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	2,772,690	-	-	(2,772,690)	-
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(1,057,328)	-	-	1,057,328	-
Add: Deferred Financing Costs	961,283	947,500	933,000	(13,783)	(14,500)
Add: Intangible Assets	4,002,494	4,150,000	4,300,000	147,506	150,000
Add: Deferred Demand Side Management Costs	127,446	166,600	-	39,154	(166,600)
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,492,744	1,399,400	1,305,900	(93,344)	(93,500)
Add: Regulatory Asset - Storm Deferral	3,002,882	-	-	(3,002,882)	-
Less: Employee Future Benefits Liability	(7,631,568)	(7,711,700)	(7,961,700)	(80,132)	(250,000)
Less (Add): Regulatory Liability OPEB	2,536,000	2,986,600	2,813,800	450,600	(172,800)
Less: Regulatory Liability - Rebates Payable to Customers	(15,453,528)	(5,507,800)	(4,648,100)	9,945,728	859,700
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	9,654,500	9,654,500	9,654,500	-
Plus: Working Capital Allowance Comprised of:	-	-	-	-	-
- Inventory	3,240,398	3,000,000	3,000,000	(240,398)	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,508,778	5,852,400	6,098,100	343,622	245,700
Income Taxes Paid X 3.6%	21,000	(21,000)	-	(42,000)	21,000
Total Rate Base	**$ 393,247,356**	**$ 412,876,800**	**$ 425,519,900**	**$ 19,629,444**	**$ 12,643,100**
Average Rate Base	**$ 386,938,159**	**$ 403,062,078**	**$ 419,198,400**	**$ 16,123,919**	**$ 16,136,322**
Actual/Requested Return on Average Rate Base	**7.02%**	**6.85%**	**6.72%**	**-0.17%**	**-0.12%**

Note - Light purple shaded items are related to the scenario's forecasted impacts on select proposed deferral balance treatment.

As seen above the rate base for Option 3B increases by $19,629,444 and $12,643,100 in 2020 and 2021 respectively.

The primary differences are related to the costs payable to (recoverable from) customers post 2003 balance and the regulatory liability – rebates payable to customers balance. Option 3B proposes the use of RORA and WNR to offset ECAM balances, with any remaining RORA balance being refunded over a period of 12-months; these changes are mirrored in the forecasted rate base with adjustments to balances/rebates payable to (recoverable from) customers. In comparison to Option 3A, Option 3B has a lesser balance in regulatory liability – rebates payable to customers in both 2020 and 2021 forecasts.

Overall, Option 3B forecasts an increase in revenue requirement, total energy charge per kWh, and total rate base in both 2020 and 2021 forecasts.

14.3.3.3 Option 3C – RORA to Offset ECAM, remaining RORA Refunded over 24 Months, WNR remain as deferred

Option 3C proposes the use of RORA to offset ECAM balances. In this option the post-2015 RORA balance would be used to offset ECAM, with any remaining RORA balance being refunded over a period of 24-months starting March 31, 2020. As part of this option the Weather Normalization Adjustment deferral account of $1,057,328 remains as a deferred amount owing to customers. In this option, the December 31, 2019 ECAM balance of $2,772,686 is offset by the RORA balance and the net RORA amount to be refunded to customers is reduced from $7,483,659 to $4,711,973. This new RORA balance would then be refunded at a rate of $0.0017 per kWh over the 24-month period commencing March 1, 2020 (based on forecast sales of 2,745,585,553 kWh from March 1, 2020 to February 28, 2022). As a result, a typical customer in each rate class would see a 2.4% increase in annual cost in 2020 and 1.1% decrease in annual cost in 2021.

Below we have outlined the proposed Revenue Requirement, Energy Charge per kWh, and Rate Base forecasts for 2020 and 2021:

Revenue Requirement

Revenue Requirement ($) - Option 3C					
	2019A	2020F	2021F	2020F - 2019A	2021F - 2020F
Operating Expenses (Net of ECAM)*	$ 153,485,663	$ 162,420,600	$ 169,392,700	$ 8,934,937	$ 6,972,100
Interest Expense (including amortization of Debt Issue Costs)	12,901,422	12,774,200	12,833,300	(127,222)	59,100
Amortization - Fixed Assets	23,337,238	28,572,100	26,202,300	5,234,862	(2,369,800)
Amortization - DSM Costs	157,198	127,400	166,600	(29,798)	39,200
Amortization - Lepreau Writedown	93,400	93,400	93,400	-	-
Amortization - Storm Deferral	-	3,002,900	-	3,002,900	(3,002,900)
Income Tax Expense	6,483,242	6,741,900	6,978,500	258,658	236,600
Return on Equity**	14,262,630	14,842,400	15,372,000	579,770	529,600
Total	**$ 210,720,793**	**$ 228,574,900**	**$ 231,038,800**	**$ 17,854,107**	**$ 2,463,900**

* *Excluding Fortis Inc. Costs*

** *Before Disallowable Costs*

As seen above revenue requirement would increase by $17,845,107 and $2,463,900 in 2020 and 2021 forecast years respectively These increases are primarily due to the increase in Operating Expenses, Amortization – Fixed Assets, and Amortization – Storm Deferral. The increase in Amortization – Fixed Assets and Amortization – Storm Deferral are consistent with other options as discussed earlier in our report. The change in Operating Expense is a direct result of the plan to use RORA to offset ECAM and WNR balance to remain as deferred instead of reducing the revenue requirement.

Energy Charge per kWh

Energy Charge per kWh - Revenue Requirement (A) - 3C					
	2019A	**2020F**	**2021F**	**2020F - 2019A**	**2021F - 2020F**
Residential - First Block	$ 0.1409	$ 0.1440	$ 0.1427	2.20%	-0.90%
Residential - Second Block	$ 0.1114	$ 0.1139	$ 0.1129	2.24%	-0.88%
General Service - First Block	$ 0.1739	$ 0.1780	$ 0.1764	2.36%	-0.90%
General Service - Second Block	$ 0.1126	$ 0.1152	$ 0.1142	2.31%	-0.87%
Small Industrial - First Block	$ 0.1703	$ 0.1743	$ 0.1727	2.35%	-0.92%
Small Industrial - Second Block	$ 0.0844	$ 0.0864	$ 0.0856	2.37%	-0.93%
Large Industrial	$ 0.0686	$ 0.0694	$ 0.0692	1.17%	-0.29%
Energy Charges per kWh - Other Amounts (B)					
ECAM Charge per kWh	$ 0.0006	$ (0.0000)	$ (0.0000)	-100.00%	916.43%
Provincial Costs Recoverable per kWh	$ 0.0054	$ 0.0042	$ 0.0041	-20.92%	-3.06%
Provincial Energy Efficiency Program per kWh	$ -	$ 0.0015	$ 0.0008	100.00%	-45.85%
Cable Contingency Fund per kWh	$ 0.0003	$ -	$ -	-100.00%	0.00%
RORA per kWh	$ (0.0034)	$ (0.0017)	$ (0.0017)	-50.20%	0.00%
Total Energy Charge per kWh Excluding Basic Revenue	**$ 0.0028**	**$ 0.0040**	**$ 0.0032**	**43.67%**	**-20.31%**
Total Energy Charge per kWh (A+B)					
Residential - First Block	**$ 0.1437**	**$ 0.1480**	**$ 0.1459**	**3.01%**	**-1.43%**
Residential - Second Block	**$ 0.1142**	**$ 0.1179**	**$ 0.1161**	**3.26%**	**-1.54%**
General Service - First Block	**$ 0.1767**	**$ 0.1820**	**$ 0.1796**	**3.01%**	**-1.33%**
General Service - Second Block	**$ 0.1154**	**$ 0.1192**	**$ 0.1174**	**3.31%**	**-1.52%**
Small Industrial - First Block	**$ 0.1731**	**$ 0.1783**	**$ 0.1759**	**3.02%**	**-1.36%**
Small Industrial - Second Block	**$ 0.0872**	**$ 0.0904**	**$ 0.0888**	**3.70%**	**-1.79%**
Large Industrial	**$ 0.0714**	**$ 0.0734**	**$ 0.0724**	**2.83%**	**-1.39%**

Option 3B would increase 2020 forecast rates between 2.83 to 3.70 percent and the 2021 forecast rates decrease between 1.33 to 1.79 percent compared to 2020 forecast rates.

Rate Base

Calculation of Rate Base ($) - Option 3C					
Components	**2019A**	**2020F**	**2021F**	**2020F - 2019A**	**2021F - 2020F**
Fixed Assets	$ 679,767,856	$ 712,215,800	$ 693,668,900	$ 32,447,944	$ (18,546,900)
Less: Capital Work in Progress	(3,750,888)	-	-	3,750,888	-
Less: Accumulated Amortization	(245,078,293)	(269,903,600)	(231,933,900)	(24,825,307)	37,969,700
Less: Contributions in Aid of Construction (net of amortization)	(23,691,857)	(24,598,000)	(25,496,000)	(906,143)	(898,000)
Less (Add): Future Income Tax Liability (Asset) - net of Long Term Receivable	(13,522,753)	(19,753,900)	(26,214,700)	(6,231,147)	(6,460,800)
Less (Add): Costs Payable to (Recoverable from) Customers Post 2003	2,772,690	-	-	(2,772,690)	-
Less (Add): Regulatory Liability (Asset) - As Established by Commission Order WNRA	(1,057,328)	(1,057,328)	(1,057,328)	-	-
Add: Deferred Financing Costs	961,283	947,500	933,000	(13,783)	(14,500)
Add: Intangible Assets	4,002,494	4,150,000	4,300,000	147,506	150,000
Add: Deferred Demand Side Management Costs	127,446	166,600	-	39,154	(166,600)
Add: Deferred Charge (Section 47(4)(a)(ii) of the EPA)	1,492,744	1,399,400	1,305,900	(93,344)	(93,500)
Add: Regulatory Asset - Storm Deferral	3,002,882	-	-	(3,002,882)	-
Less: Employee Future Benefits Liability	(7,631,568)	(7,711,700)	(7,961,700)	(80,132)	(250,000)
Less (Add): Regulatory Liability OPEB	2,536,000	2,986,600	2,813,800	450,600	(172,800)
Less: Regulatory Liability - Rebates Payable to Customers	(15,453,528)	(7,213,572)	(5,119,772)	8,239,956	2,093,800
Add: Reg Asset - CTGS Accumulated Reserve Variance	-	9,654,500	9,654,500	9,654,500	-
Plus: Working Capital Allowance Comprised of:	-	-	-	-	-
- Inventory	3,240,398	3,000,000	3,000,000	(240,398)	-
- Gross Operating Expenses X 3.6% (net of disallowed costs)	5,508,778	5,852,400	6,098,100	343,622	245,700
Income Taxes Paid X 3.6%	21,000	(21,000)	-	(42,000)	21,000
Total Rate Base	**$ 393,247,356**	**$ 410,113,700**	**$ 423,990,800**	**$ 16,866,344**	**$ 13,877,100**
Average Rate Base	**$ 386,938,159**	**$ 401,680,528**	**$ 417,052,300**	**$ 14,742,369**	**$ 15,371,772**
Actual/Requested Return on Average Rate Base	**7.02%**	**6.87%**	**6.76%**	**-0.14%**	**-0.11%**

Note - Light purple shaded items are related to the scenario's forecasted impacts on select proposed deferral balance treatment.

As seen above the rate base for Option 3C increases by $16,866,344 and $13,877,100 in 2020 and 2021 respectively.

The primary differences from actual to forecast within the table above are related to the costs payable to (recoverable from) customers post 2003 balance, the regulatory liability – rebates payable to customers balance, and the regulatory liability (asset) – as established by commission order WNRA. Option 3C proposes the use of RORA to offset ECAM, with any remaining RORA balance being refunded over a period of 24-months and recovery of WNR balance excluded from revenue requirement; these changes are forecasted in rate base as adjustments to balances/rebates payable to (recoverable from) customers and regulatory liability – as established by commission order WNRA being increased from $Nil to $1,057,328. In comparison to Option 3A, Option 3C has a larger balance in regulatory liability – rebates payable to customers in both 2020 and 2021 forecasts and includes a balance of $1,057,328 relating to the commission order WNRA which is included in the total rate base calculation.

Overall, Option 3C forecasts an increase in revenue requirement and total rate base in both 2020 and 2021 forecasts. Additionally, energy charge per kWh would be increased in 2020 forecast and decreased in 2021 forecast.

1. Appendix A – General Rate Application Contents

During the course of our review we noted that MECL was very responsive to all of our queries. However, some of those queries could be alleviated in future applications if the originally submitted application was mindful of the following:

- All tables and calculations could be provided in their original native form. We define native form as being the original medium used to perform the analysis. For example, the native form financial models and (excel) with any underlying calculations and supporting materials also filed as supplementary evidence to support the application,
- Supplemental narratives or descriptions of the steps taken to prepare an analysis could also be included to clarify methodologies used and quality control processes in place to demonstrate that MECL has completed a process to ensure the evidence files is free from error.

To expedite future general rate applications, we recommend that the staff of IRAC and MECL review the following information listing in advance of the preparation of the application to discuss expectations on a preliminary basis the information that will be provided when the application is filed. We would expect general rate applications to include the following information:

1.0 Purpose/Introduction

- 1.1 Application Background
  - 1.1.1 About Maritime Electric – purpose, who they service.
  - 1.1.2 Customer Expectations – reliability of service, reasonable pricing, communication.
  - 1.1.3 Maritime Electric's Performance – discussion of company's overall performance (customer outages, assets, cost management, reliability, pricing, energy conservation).
  - 1.1.4 Electricity Sector Developments – new electricity developments since last application, if any.
  - 1.1.5 Risk and Return – cost of capital, business risks, economy applicable to the application.
- 1.2 Application proposals – Description of the overall impact on rates and what they have proposed
  - 1.2.1 Year 1 and Year 2 Revenue Requirements – including explanations of what is being requested, the impact, effective date, primary reasons the impact occurred.
  - 1.2.2 Customer Rates, Rules and Regulations – impact of customer rates, schedule of rates (both current and proposed), and any new service offerings, if applicable.
  - 1.2.3 Other proposals (if applicable).

2.0 Customer Operations

- 2.1 Customer Service Delivery
  - 2.1.1 Customer Expectations – description of customer contacts, communication (i.e.: increasing digital usage).
  - 2.1.2 Balancing Costs and Service – service efficiencies (i.e.: ebills stats), customer satisfaction (i.e.: index), ensuring continuity in customer service delivery.
  - 2.1.3 Customer Conservation – conservation plan in place (if any), costs and savings from customer participation, future customer conservation programming.
- 2.2 Operations and Reliability Management
  - 2.2.1 System Overview – who services are provided to (percentage of population, area).
  - 2.2.2 Electrical System Performance – general commentary, comparison to other Canadian utilities, significant events, reliability management.
  - 2.2.3 Field Responsiveness – performance (comparing to Canadian average for outages), capabilities.

2.3 Operating and Capital Costs

2.3.1 Overall description of the forecast methodology used, if there have been any changes to this methodology in recent years, description of the internal quality review process included in the forecast and the accuracy of the budget/forecast in the three previous years.

2.3.2 Operating Costs – gross operating costs and operating costs by function, cost classification, or category.

2.3.2.1 Provide three prior years of actuals vs the budget/forecast for the period, and explanations for variances.

2.3.2.2 Budget/forecast model in its native form (i.e. excel including underlying calculations) with support for any material assumptions included in the analysis.

2.3.3 Capital Costs – capital expenditures by asset class.

2.3.3.1 Provide three prior years of actuals, vs the budget/forecast for the period, and support for variances.

2.3.3.2 Capital Budget/forecast model in its native form (i.e. excel including underlying calculations) for the rate setting period with support for any material assumptions included in the analysis.

3.0 Finance

3.1 Financial Performance

3.1.1 Revenue – table and supporting documentation detailing the energy sales and electricity revenue for three prior years of actuals vs the budget/forecast for the period (i.e.: billed revenue broken down monthly with energy sales and revenue from rates, base purchased power, and deferral mechanisms impacting the revenues included), including a breakdown of other revenue and necessary supporting materials in its native form (i.e. excel including underlying calculations).

3.1.2 Power Supply – summary/table of power supply costs for three prior years of actuals vs the budget/forecast for the period, provide supporting materials of calculations in its native form (i.e. excel, included within supporting calculations for revenues, as mentioned above), and provide explanations for increases and/or decreases year over year.

3.1.3 Depreciation – summary/table showing depreciation expense for three prior years of actuals vs the budget/forecast for the period, explanations for year over year variances, and the supporting calculations in its native form (i.e. excel including underlying calculations). Additionally, provide the depreciation study which has been relied upon in their application.

3.1.4 Employee Future Benefits – summary/table showing actual employee future benefits for three prior years vs the budget/forecast for the period, provide explanations for variances, and supporting materials.

3.1.5 Finance Charges - summary/table showing actual finance charges expenses for three prior years vs the budget/forecast for the period, provide explanations for increases or decreases year over year, and supporting materials in its native form (i.e. excel including underlying calculations) for how the calculations for each year was derived.

3.1.6 Income Taxes - summary/table showing actual income tax expenses and effective income tax rate for three prior years vs the budget/forecast for the period, provide explanations for increases or decreases year over year with supporting materials.

3.1.7 Returns - summary/table showing actual rates of return for three prior years of actuals vs the budget/forecast for the period, provide explanations for increases or decreases year over year with supporting materials.

3.1.8 Credit Metrics - summary/table showing credit metrics for three prior years of actuals vs the budget/forecast for the period, provide explanations for increases or decreases year over year.

3.2 Cost of Capital

3.2.1 Regulatory Update – background summary of the process to arrive at the cost of capital assumption in the application and the final assumption applied in their calculations.

3.2.2 Impact of Proposed Returns – comparison of the Company's forecasted financial performance for the rate setting period based on existing versus proposed scenarios (i.e. Comparative rates of return, credit metrics).

3.3 Regulatory Accounting Matters – general commentary on accounting standards applied and updates if any, existing versus proposed treatment (if any proposals), use comparative tables detailing existing versus proposed calculations if updates proposed occurred, impact on revenue requirement for existing versus proposed (if any).

3.4 Regulatory Amortizations

3.4.1 Overview – summary/table of amortization of regulatory deferrals previously approved and amortization of regulatory deferrals proposed in the application, showing the impact on revenue requirement, provide separate explanations for new regulatory deferrals set up in this application (seeking approval), and provide details on updates to current deferral mechanisms (if any).

3.4.2 Energy Cost Adjustment Mechanism – discussion on deferral mechanism, dollar impact, implementation (i.e.: rate rider), proposed recovery/refunding method, conclude on if this is consistent with previous practices or not, usage of account in the past (if applicable), supporting calculations on how the dollar/rate impact was derived.

3.4.3 Rate of Return Adjustment (RORA) - discussion on deferral mechanism, dollar impact, implementation (i.e.: rate rider), proposed recovery/refunding method, consistent with previous practices or not, usage of account in past (if applicable), supporting calculations on how the dollar/rate impact was derived.

3.4.4 Weather Normalization Mechanism - discussion on deferral mechanism, dollar impact, implementation (i.e.: rate rider), proposed recovery/refunding method, consistent with previous practices or not, usage of account in the past (if applicable), supporting calculations on how the dollar/rate impact was derived.

4.0 Rate Base and Revenue Requirement

4.1 Overview

4.2 Rate Base - forecasted average rate base for the rate setting period, what are the changes to average rate bases and why, providing supporting materials in its native form (i.e. excel including underlying calculations) of the full calculation (Plant Investment, Additions to Rate Base, Deductions from Rate Base, Working Capital Allowance).

4.3 Revenue Requirement

4.3.1 Summary of Revenue Requirements for the rate setting period – breakdown showing each cost impacting revenue requirement, plus/less adjustments to provide total revenue requirement from rates.

4.3.2 Costs and Depreciation – breakdown of costs included in revenue requirement for the forecasted years (provide tables for each separate cost proposed during the forecasted years), additional support to show how each individual costs was calculated in its native form (i.e. excel including underlying calculations), and overall revenue requirement calculation for each year in the rate setting period.

4.3.3 Return on Rate Base – summarization (table) of the proposed return on rate base, in addition to supporting materials in its native form (i.e. excel including underlying calculations) of the calculation in each of the forecasted years.

4.3.4 Deductions from Revenue Requirement – summarization (table) of the proposed deductions form revenue requirement for rate setting period, and additional supporting materials in its native form (i.e. excel including underlying calculations) for the calculations of each line item.

4.3.5 Required Revenue Increases - summarization (table) of the require revenue increases for the rate setting period, and additional supporting materials for the calculations of each line item (i.e. revenue from rates).

5.0 Customer Rates

5.1 Overview

5.2 Customer, Energy and Demand Forecast

5.2.1 Customers Served – discussion on customers Maritime Electric is responsible for, table presenting the company's customer base (percentage of total customers, percentage of total energy sales).

5.2.2 Forecast – discussion on the methodology applied and tables detailing customers and energy sales for three prior years of actuals vs the budget/forecast for the period.

5.2.3 Provide explanations for variances year over year. Provide any supporting materials in its native form (i.e. excel).

5.2.4 Provide any reports pertaining to the customer, energy and demand forecast.

5.3 Rate Change Plan

5.3.1 Embedded Revenue to Cost ("RTC") Ratio – demonstrate that the RTC ratio on the proposed rates is 90 to 110 percent for the current application. Including the calculation of the RTC. The utility should also acknowledge that the Commission deems an RTC of 95 to 105 as an appropriate target and demonstrate that they have a plan in place to work towards this target prior to the next GRA.

5.3.2 Rate Design Study – Provide an update on the most recent rate design study including and current and potential future impacts that this study might have on this application. Also comment on the timeline to the next study if applicable.

5.4 Proposed Rates

5.4.1 General – provide a schedule of existing and proposed customer rates on the proposed effective date (summary of existing compared to proposed, use a change/formula column to allow recalculation of change), provide supporting materials in its native form (i.e. excel) on the customer rate impacts for different customer class services, support for the reconciliation of the forecasted revenue from rates to the Company's revenue requirement.