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A FORTIS COMPANY

November 26, 2020

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

Dear Ms. Mosher:

General Rate Application - Docket UE20944
Response to Interrogatories from Mr. Roger King

Please find attached the Company's response to Interrogatories from Mr. Roger King with respect to Docket UE20944 – General Rate Application and the Application submitted by the Company for electric rates effective March 1, 2020 and March 1, 2021.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

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

GCC22
Enclosure
cc: Nicole McKenna – Carr, Stevenson & MacKay

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MARITIME ELECTRIC
A FORTIS COMPANY

Via email: randjking@pei.sympatico.ca

November 26, 2020

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

Dear Mr. King:

General Rate Application
Doc. UE20944
Response to Interrogatories

Please find attached the Company's response to your Interrogatories with respect to Docket #UE20944 - General Rate Application and the Application submitted by the Company for electric rates effective March 1, 2020 and March 1, 2021.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

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

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cc IRAC – Cheryl Mosher

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Reference the above IRAC Notice of Application, please find my questions related to the February 2020 MECL Updated Filing as below.

IR-1 For the CTGS Decommissioning project, the November 2018 GRA cites three (3) potential customer costs:

1. $14.5 million to be recovered from the cost of decommissioning
2. An accumulated reserve variance estimated to be $16.245 million.
3. The estimated $10.43 million (2018 dollars) net decommissioning cost

By adding the amounts for the current total decommissioning costs, the CTGS capital reserve and the current CTGS book value to this list please explain how the customer costs were derived. Please also explain how variances against the capital reserve have occurred and provide the reasoning why there will have to be additional customer contributions.

Response:

In paragraph 210 of Order UE19-08, the Commission states that the estimated total cost of the Company's Decommissioning Plan is $14.5 million, which is comprised of: (i) $11.3 million in net decommissioning costs; and (ii) $3.2 million in estimated costs of constructing a new Balance of Plant ("BOP") building to house the equipment associated with the Combustion Turbine 3 ("CT3"), which is currently located in the existing Charlottetown Thermal Generating Station ("CTGS"). When the estimated net decommissioning cost of $10.43 million, in 2018 dollars, listed as item three in the above question is escalated to 2022 dollars (at two per cent per annum[1]) the calculated amount is $11.3 million. Therefore, item three is included in one in the above question.

The $3.2 million BOP was proposed in the November 2018 General Rate Application ("GRA") and in the Company's 2020 Capital Budget Application as a cost-effective alternative to repurposing the existing CTGS, or a portion thereof, to house CT3 once decommissioning of the steam plant assets are completed. This portion of the decommissioning plan was denied by the Commission in Order UE19-08. However, it should be noted that without the construction of a BOP building, the cost of repurposing the CTGS, or a portion thereof, will need to be added to the cost of decommissioning and is considered a higher cost alternative over the remaining life of CT3.

The accumulated reserve variance estimated to be $16.245 million, item two in the question above, is as of January 1, 2019 and was derived from the 2017 accumulated reserve variance of $18,006,977[2] less the adjustments for 2018 variance depreciation as outlined in Appendix 10 of the 2018 GRA. A copy of Appendix 10 is provided as Attachment 1 to this response for reference.

[1] See Part IV. Net Salvage Considerations, paragraph 3 of the Gannett Fleming 2017 Depreciation Study filed with the Commission on June 29, 2018.
[2] See Part VI. Results of Study, page VI-7 Column 5 for TOTAL STEAM PRODUCTION PLANT.

An accumulated reserve variance occurs when there has not been sufficient depreciation recovered through rates. The depreciation recovered is considered sufficient when it approximately equals (i) the capital cost of the asset plus; and (ii) the estimated cost of removal, net of any salvage proceeds, at the end of an asset's useful life. As such, the accumulated reserve variance is measured at a point in time. As time passes and changes in the underlying assumptions occur, such as the timing of changes in depreciation rates or changes in the estimated cost of removal, the accumulated reserve variance is re-measured, usually with an update to the depreciation study.

Section 23 of the EPA states that:

> *"Every public utility shall carry a proper and adequate depreciation account when the Commission, after investigation, determines that the depreciation account can be reasonably required; the Commission shall ascertain and determine what are proper and adequate rates of depreciation of the several classes of property of each public utility."*

Proper and adequate depreciation requires the Company to maintain depreciation accounts whereby, over the useful life of the various asset classes, the capital cost of each asset is expensed and recovered from customers as a cost of providing electric service. Depreciation expense is calculated by applying the depreciation rates assigned to the various asset classes. Under good utility practice, proposals for changes to depreciation rates are brought to the regulator based upon studies conducted by experts who determine the average service lives of the assets for purposes of calculating the appropriate depreciation rates by examining the Company's various asset classes.

Since returning to cost of service regulation, the Company has filed with the Commission three depreciation studies prepared by depreciation experts, Gannett Fleming. The first study was filed on August 31, 2006 based on results as at December 31, 2005. By Order UE07-01, the Commission ordered that the existing rates of depreciation remain in effect until otherwise ordered.

The second study was filed with the Commission on July 23, 2015 based on results as at December 31, 2014 (the "2014 Study"). The 2014 Study was prepared in support of recommended changes to depreciation rates to be adopted in 2016 and used in calculating depreciation expense for purposes of determining customer electricity rate adjustments commencing March 1, 2016.

The 2014 Study recommended revisions to the annual depreciation rates based on the remaining average service life of the various asset classes and a prudent allowance for the costs of removal of the assets upon retirement.

Upon consideration of the 2014 Depreciation Study results, which would have resulted in a significant increase in depreciation expense, the Company proposed to (i) adopt the recommended depreciation rates; (ii) adopt the amortization of the accumulated reserve variance for the CTGS; and (iii) defer the amortization of the accumulated reserve variance on all other asset classes. The Company believed that these proposals struck a reasonable balance between the impact on customer electricity costs resulting from a higher depreciation expense and the need to fully depreciate the CTGS assets prior to the facility's closure and decommissioning. The Company's General Rate Application, filed on October 21, 2015, and the subsequent General Rate Agreement filed with the Commission for approval on February 5, 2016, incorporated the proposed new depreciation rates and amortization of the accumulated reserve variance for the CTGS.

In the 2017 Gannet Fleming Depreciation Study, the recommended changes in depreciation rates, including the recommended changes in the accumulated reserve variance amortization were driven primarily by the following factors:

i. revisions to the estimated remaining service lives of the CTGS assets to reflect the planned staged retirement of the facility;
ii. updated costing information from the CTGS Decommissioning Study regarding the estimated cost of decommissioning and removal;
iii. changes in the average service life and cost of removal assumptions used by Gannett Fleming in the 2017 Study as compared to the 2014 Study; and
iv. one-year delay (2015) in the implementation of revised depreciation rates from the 2014 Depreciation Study which contributed to the increase in the accumulated reserve variance.

In Part IV of the 2017 Depreciation Study, Gannett Fleming used the 2018 Decommissioning Study estimates prepared by GHD Limited of $10.43 million (item three in the above question) and escalated it to 2022 dollars for a decommissioning cost estimate of $11.3 million. This escalated value results in a negative net salvage percentage of 19 per cent as outlined on Page VIII-2 of the 2017 Study. By comparison, the 2014 Depreciation Study used a negative net salvage percentage of 10 per cent and calculated the estimated decommissioning cost to be approximately $6.2 million. The increase in the net salvage percentage, along with the time value of money, resulted in an increase of $5.1 million in the reserve variance from that calculated in the 2014 study to the 2017 study.

In Order UE19-08, the Commission ordered the Company to adopt all of the recommendations in the 2017 Depreciation Study, including the adoption of the proposed depreciation rates and the amortization of the accumulated reserve variance for all assets as of January 1, 2020. However, as discussed in Section 9 of the Company's Application for an Order approving changes to the Schedule of Rates effective March 1, 2020 and March 1, 2021 ("Application"), the Company does anticipate that there will be an accumulated reserve variance when the CTGS is removed from service on December 31, 2021 that will require future recovery from customers for two reasons:

1. In the 2017 Depreciation Study, the depreciation rates were calculated based on an assumed implementation date of January 1, 2018. The two year delay (2018 and 2019)

in the approved implementation of the revised depreciation rates has will result in a forecast reserve variance of $5,989,936[3] as of December 31, 2021.

2. The 2017 Depreciation Study also assumed a full year of depreciation would be recorded in the final year of retirement. As is common accounting practice, the Company follows a half-year rule and records one half year of depreciation in the year of addition and in the year of retirement based on the assumption that assets are generally acquired and disposed of during the year as opposed to at the beginning or end of the year. This half-year rule will result in a further $3,664,588[3] forecast reserve variance as of December 31, 2021.

The total forecast variance of $9.6 million was provided in Appendix 8 of the Application, and a copy is provided as Attachment 2 for reference.

[3] See Appendix 8, Estimate of Unrecovered Depreciation and Accumulated Reserve Variance for the CTGS, of the Application for an Order Approving Changes to the Schedule of Rates Effective March 1, 2020 and March 1, 2021.

IR-2 The current annual payment schedule for the PEI Accord Debt is around $6M. Please provide:

1. What was the reduction in annual payments when a proportion of the NB Power insurance payment for Pointe Lepreau refurbishment was set against the remaining debt?
2. What are the proportions of the current annual payment each due to the Pointe Lepreau and Dalhousie projects? When will the Dalhousie debt be paid in full?
3. Is it correct to assume that this Pointe Lepreau annual payment is not included in the ECAM schedule showing Pointe Lepreau annual energy purchase costs?

Response:
The New Brunswick Energy and Utility Board ("NBEUB") issued a ruling on April 4, 2018 that the nature of the information relating to the insurance settlement is confidential. The circumstances of New Brunswick Power's Claim for Confidentiality are unique and any undue disclosure of the settlement terms would be detrimental to New Brunswick Power and ratepayer interests.[4]

In addition, the debt associated with the incremental energy costs related to the Point Lepreau refurbishment and the Dalhousie Exit Agreement were assumed and remain with the Province of PEI and not with Maritime Electric. Therefore, the Company is not at liberty to disclose specific information on the financing terms including annual payments and how these are allocated between the Dalhousie and Point Lepreau debt.

As ordered by the Commission in Order UE19-08, the Provincial Costs Recoverable remains a rider and are not included in Point Lepreau annual energy purchase costs in the ECAM schedule.

[4] NBEUB Decision Matter No. 375 dated July 20, 2018, Paragraph 21

IR-3 The November 6 2020 "Interrogatories of Commission Staff" document refers to a Revenue Shortfall Deferral Account and the CTGS Accumulated (Variance) Reserve. What now are the estimates for each amount and over what period is it proposed to recover (from customers) each amount, assuming that the new rates are implemented as per the Commission's document - namely January 1 2021. How are the $10.43M/$14.5 CTGS decommissioning costs to be recovered?

Response:

Revenue Shortfall Deferral Account:
As discussed in our response to Commission Staff IR-95, in May 2020 the Company requested that the Commission consider a revenue shortfall deferral account to reflect the revenue lost in the interim period in order to meet its 2020 revenue requirement and the deferral be recovered through customer rates over the remaining rate setting period. At that time, the Company provided a calculation of the revenue shortfall deferral based on a September 1, 2020 rate implementation of $1,525,240 which reflected a revenue shortfall from March 1, 2020 to August 31, 2020 and recommended that it be collected over the remaining rate setting period of 18 months (September 1, 2020 to February 28, 2022).

Assuming the proposed rates will be implemented effective January 1, 2021, the Company recalculated the 2020 revenue shortfall to be $2,556,928 for the March 1, 2020 to December 31, 2020 period and recommends that it be collected over the remaining rate setting period of 14 months (January 1, 2021 to February 28, 2022).

It should be noted that in IR-96 the Commission directed the Company to calculate the 2020 revenue shortfall on a different basis from that calculated and proposed by the Company in its response to IR-95. Even though the 2020 revenue requirements calculated in IR-95 and IR-96 are different, the recovery period remains the same 14 month period.

The amount to be recognized as a revenue shortfall and its recovery period is subject to final determination and approval of the Commission.

CTGS Reserve Variance:
As stated in our response to IR-1 above, the Company forecasts a CTGS Accumulated Reserve Variance of $9.6 million when the assets are retired on December 31, 2021, which will require future recovery from customers. In Section 9.0 of the January Filing, the Company proposed establishing a regulatory deferral account for this accumulated reserve variance, and to recover the variance in the next rate setting period with a target amortization of two years (2022 and 2023) for the following reasons.

The first reason was to mitigate the impact on customer rates that resulted from the adoption of the 2017 Depreciation Study depreciation rates effective January 1, 2020, as directed in Order UE19-08. This adoption of depreciation rates resulted in an increase of more than $5 million in the forecast depreciation expense in 2020 compared to the depreciation expense recovered in 2019 rates.

Second, deferring the recovery of the CTGS reserve variance will allow the amount to be updated to reflect the results of a new depreciation study based on financial results up to December 31, 2020 and provide a more accurate calculation of the balance to be recovered.

Finally, deferring the recovery of the CTGS reserve balance until 2022 and 2023 will allow its recovery over the same period as the completion of the decommissioning activities.

The Company still considers the above noted reasons valid and has recommended that the Commission defer the recovery until the next rate setting period.

GRA APPENDIX 10
CTGS PROJECTED ACCUMULATED RESERVE VARIANCE AS AT DECEMBER 31, 2018

CTGS Steam Production Plant	Original Cost At 12/31/2017	Annual Depr Accrual Amt Per 2017 Study	Annual Depr Accrual Amt Per UE16-04	2018 Depr Shortfall	Reserve Variance 12/31/2017	Res Var Amort Per UE16-04	Projected Reserve Variance 12/31/18
	(A)	(B)	(C)	(D) = (B) - (C)	(E)	(F)	(G) = (E) - (F) + (D)
Structures and Improvements	9,006,038	547,357	481,823	65,534	2,970,357	360,242	2,675,649
Boiler Plant Equipment	26,445,980	1,285,317	1,198,003	87,314	6,788,125	825,115	6,050,324
Turbogenerator Units							
Unit 7	1,954,691	113,005			727,030		
Unit 8	3,909,382	209,582			1,393,541		
Units 9 and 10	15,637,528	796,856			5,344,433		
Subtotal - Turbogenerator Units	21,501,600	1,119,443	943,920	175,523	7,465,004	819,211	6,821,316
Accessory Electrical Equipment	2,283,113	68,942	63,699	5,243	448,151	53,653	399,741
Miscellaneous Power Plant Equipment	1,512,887	68,526	63,390	5,136	335,340	42,361	298,115
Total	60,749,618	3,089,585	2,750,835	338,750	18,006,977	2,100,581	16,245,146

Appendix 8
Estimate of Unrecovered Depreciation and Accumulated Reserve Variance for the CTGS

	Actual							
	Orginial Cost at 12/31/2017	Net Addtions and Retirements 2018	Net Addtions and Retirements 2019	Orginial Cost at 12/31/2019	Forecast 2020 Retirement	Orginial Cost at 12/31/2020	Forecast 2021 Retirement	Orginial Cost at 12/31/2021
Structures and Improvements	9,006,038	(1,188)	56,995	9,061,845	-	9,061,845	(9,061,845)	-
Boiler Plant Equipment	26,445,980	(2,597)	(650,236)	25,793,147	-	25,793,147	(25,793,147)	-
Turbogenerator Units								
Unit 7	1,954,691	-	(1,954,691)	-		-		-
Unit 8	3,909,382	-	-	3,909,382	(3,909,382)	-	-	-
Units 9 and 10	15,637,528	8,464	-	15,645,992		15,645,992	(15,645,992)	-
Total Turbgenerator Units	21,501,601	8,464	(1,954,691)	19,555,374	(3,909,382)	15,645,992	(15,645,992)	-
Accessory Electrical Equipment	2,283,113	-	-	2,283,113		2,283,113	(2,283,113)	-
Miscellaneous Power Plant Equipment	1,512,887	-	-	1,512,887		1,512,887	(1,512,887)	-
	60,749,619	4,680	(2,547,932)	58,206,367	(3,909,382)	54,296,985	(54,296,985)	-
Decommissioning Costs, net of salvage	11,298,000	(760,052)	(398,340)	10,139,608	(415,000)	9,724,608		
	72,047,619			68,345,975		64,021,593		

	Accumulated Depreciation ("A/D") 12/31/2017	2018	2018 Retirements & Retirement Expense	2019	2019 Retirements & Retirement Expense	A/D 12/31/19
Amortization Expense - Actual						
Structures and Improvements	5,576,582	842,009	(681,135)	844,618	(398,170)	6,183,904
Boiler Plant Equipment	19,588,953	2,023,018	(77,415)	1,998,047	(652,576)	22,880,027
Turbogenerator Units						
Unit 7	1,373,687	160,285	(13,422)	80,143	(1,954,861)	(354,168)
Unit 8	2,633,028	320,569		320,569		3,274,166
Units 9 and 10	10,098,042	1,282,624		1,282,971		12,663,637
Total Turbgenerator Units	14,104,757	1,763,478	(13,422)	1,683,683	(1,954,861)	15,583,635
Accessory Electrical Equipment	1,996,684	117,352		117,352		2,231,388
Miscellaneous Power Plant Equipment	1,196,410	105,751		105,751		1,407,912
	42,463,386	4,851,608	(771,972)	4,749,451	(3,005,607)	48,286,866
Asset Retirements			11,920		2,607,267	
Retirement Expense			760,052		398,340	

Annual Depreciation Rate UE19-08	Forecast Amortization Expense - per 2017 Study	A/D 12/31/2017	2018	2018 Retirements & Retirement Expense	2019	2019 Retirements & Retirement Expense	2020	2020 Retirements & Retirement Expense	2021		
14.41%	Structures and Improvements	5,576,582	1,297,684	(681,135)	1,301,705	(398,170)	1,305,812	(415,000)	652,906		
11.34%	Boiler Plant Equipment	19,588,953	2,998,827	(77,415)	2,961,811	(652,576)	2,924,943		1,462,471		
	Turbogenerator Units										
24.47%	Unit 7	1,373,687	478,313	(13,422)	239,156	(1,954,861)	-		-		
17.32%	Unit 8	2,633,028	677,105	-	677,105		338,552	(3,909,382)	-		
13.70%	Units 9 and 10	10,098,042	2,142,921	-	2,143,501		2,143,501		1,071,750		
	Total Turbgenerator Units	14,104,757	3,298,339	(13,422)	3,059,762	(1,954,861)	2,482,053	(3,909,382)	1,071,750		
7.99%	Accessory Electrical Equipment	1,996,684	182,421	-	182,421		182,421		91,210		
10.18%	Miscellaneous Power Plant Equipment	1,196,410	154,012	-	154,012		154,012		77,006		
		42,463,386	7,931,283	(771,972)	7,659,712	(3,005,607)	7,049,241	(4,324,382)	3,355,344	60,357,005	3,664,588
	Difference - Study less Actual	-	**3,079,675**		**2,910,261**						**3,664,588**
			A		**B**						**C**
	Composite Rate		13.06%		13.16%		12.98%		12.36%		

The Composite rate is decreasing due to the retirement of Unit 7 in 2019 & Unit 8 in 2020, both at higher rates than remaining assets

Total Balance Remaining to be collected at the end of 2021 - Regulatory Deferral (proposed)	**D = A + B + C**	**$ 9,654,524**