Ontario Energy Board

Chapter 2 Appendices

Filing Requirements for Electricity Distribution Rate Applications

Version 2.2 (2016)

Utility Name	Chapleau Public Utilities Corporation
Assigned EB Number	EB-2015-0060
Name of Contact and Title	Alan Morin - Manager
Phone Number	705-864-0111
Email Address	cpuc@ontera.net
Test Year	2016
Bridge Year	2015
Last Rebasing Year	2012
Identify the accounting standard used for the test year	MIFRS
Did you update your depreciation and capitalization policies?	Yes
When did you update your depreciation and capitalization policies?	January 1 **2013**
Identify the year that the applicant has adopted or is expected to adopt IFRS for financial reporting purposes	2015 or Later
Are you applying for cost recovery for the test and/or future year(s) for Green Energy initiatives?	Yes
Is Chapleau Public Utilities Corporation an	Yes

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

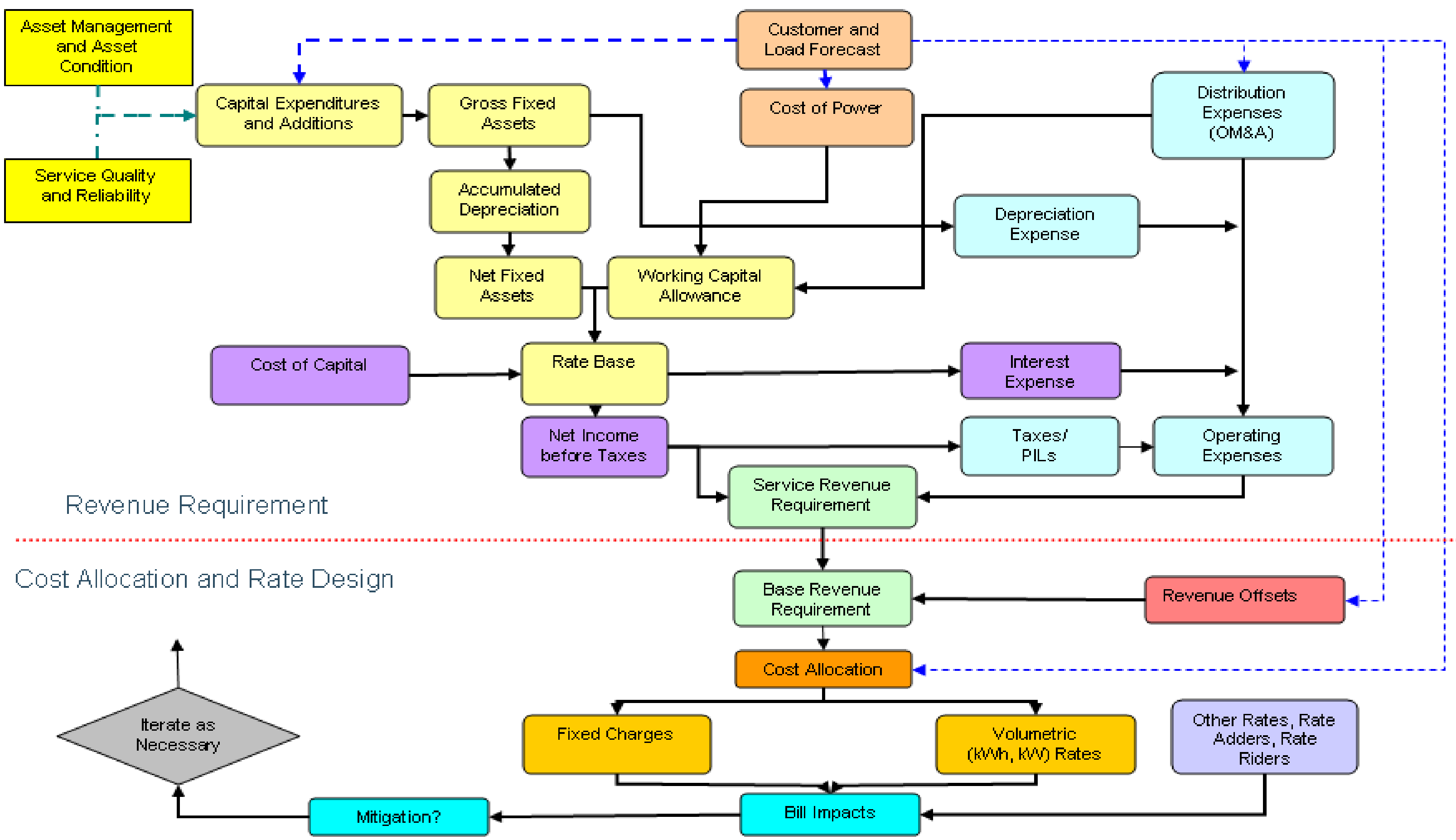
Ontario Energy Board

Chapter 2 Appendices

Filing Requirements for Electricity Distribution Rate Applications

Cost of Service Rate Application Schematic

The Cost of Service Rate Application Schematic is a flowchart appended to Chapter 2 of the Filing Requirements as a guide for the components of an application and how demand and costs interrelate to derive the revenue requirement and then how the revenue requirement is allocated between classes and through fixed/variable splits to derive rates that will be compensatory for the annual revenue requirement, based on the the forecasted demand. There is no form to be filled out; therefore, this Schedule is not required to be filed.



List of Key References

A list of key references for understanding the Filing Requirements has been embedded in the document below. To access the list of references and associated hyperlinks double-click the icon below.

Adobe Acrobat Document

File Number:	EB-2015-0060
Exhibit:	2
Tab:	
Schedule:	
Page:	36
Date:	10-Aug-16

Appendix 2-AA
Capital Projects Table

Projects	2011	2012	2013	2014	2015 Bridge Year	2016 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**
Project Name #1						
Oak Street - Replace 45' class 3 pole	900					
Planner Rd - reolace 40' class 3 pole &25 kV transformer		2,432				
Substation - Hot Oil clean T3 & Add/Replenish inhibitorT3 & T4			34,700			
Planer Rd. Pole #603 & #605 - replace 40' class 4 poles				1,680		
Monk St. Replace 55' pole, #250, & insulators					29,548	
Construction Work-in-Progress - Substation						785,000
Sub-Total	900	2,432	34,700	1,680	29,548	785,000
Project Name #2						
Monk St. - Replace 45' class 3 pole & 75kV transformer	4,050					
Laneway @ Birch St - replace 45' Class 3 pole &75kV transformer		3,780				
Birch St. (Lane behind RBC) Change 50' class 3 pole &3 50kV transformers			13,526			
Martel Rd. Pole #635 - Replace 40' class 4 pole				840		
Replace pole #222 and 3 Trasformers					7,443	
Replace 45' pole #197 and 50kV Trasformer - Pine St.						3,801
Sub-Total	4,050	3,780	13,526	840	7,443	3,801
Project Name #3						
Golf Cource Rd & Demers - Replace 40' class 3 pole & span guy	1,124					
Refurbish 3 old regulators @ substation		15,406				
Asset Management Plan			40,000			
Martel Rd. Pole #631 - Replace 40' class 4 pole & switches				6,160		
Lorne St. Replace pole #169					1,813	
Replace 50' pole #199 - Corner of Pine & Young						31,073
Sub-Total	1,124	15,406	40,000	6,160	1,813	31,073
Project Name #4						
Martel Rd. - replace 45' class 4 pole	860					
Demers St. - Rebuild		730				
Demers St. - Rebuild Completed				9,403		
Gervais Trailer Park - Replace pole					795	
Replace back guy pole, 35' Class 4 pole #25 - Connaught St.						1,320
Sub-Total	860	730	0	9,403	795	1,320
Project Name #5						
Underground backup supply	3,516					
Smart Meters		381,117				
Substation Rd. - Replace 40' class 4 pole & relogate transformer				840		
Aberdine Lane - Replace pole					1,460	
Replace 40' Class 4 Pole #77 - Grey St. Lane						1,470
Sub-Total	3,516	381,117	0	840	1,460	1,470
Project Name #6						
Computer Software (Smart Meters)		57,476				
Asset ManagementPlan				25,000		
Birch St. & Martel - Peplace Poles					440	
Sub-Total	0	57,476	0	25,000	440	0
Miscellaneous		113				
Total	**10,450**	**461,054**	**88,226**	**43,923**	**41,499**	**822,664**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***						
Total	**10,450**	**461,054**	**88,226**	**43,923**	**41,499**	**822,664**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2016*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2011			2012			2013			2014			2015			2016	2017	2018	2019	2020
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access			--		382	--			--			--			--					
System Renewal		10	--			--		14	--		19	--		41	--	38	36	200	200	200
System Service			--		15	--		35	--			--			--					
General Plant			--		57	--		40	--		25	--			--	785	800			
TOTAL EXPENDITURE	-	10	--		455	--		88	--	-	44	--	-	41	--	823	836	200	200	200
System O&M			--			--			--			--			--					

Notes to the Table:
1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year): 9

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Notes on year over year Plan vs. Actual variances for Total Expenditures

Notes on Plan vs. Actual variance trends for individual expenditure categories

File Number:	EB-2015-0060
Exhibit:	1
Tab:	
Schedule:	
Page:	50
Date:	10-Aug-16

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
In 2014 Chapleau PUC engaged Burman Energy to develop their Distribution System Plan and to recommend ways to reduce CPUCs energy losses, improve service reliability and safety. The investment strategy chosen by both CPUC and the Township Council would entail a significant capital investment and Chapleau PUC wanted to inform their customers and retained consultants to develop and execute tailored consumer research. In 2014 the customer surveywas conducted, using telephone interviews of 100 Chapleau PUC customers in both French and Engish. 20% of respondents were French speaking. Chapleau PUC targeted questions to canvass customer satisfaction in the following areas. Chapleau PUC targeted questions to canvass customer satisfaction in the following key areas: • power quality and reliability • price and bill impact • communications • and the customer service experience This Customer Survey also considered, and included, an educational introduction to be shared with the customer. This introduction provided feasible information about Chapleau PUC's operations and their need for customer considerations and feedback.	**Customer Satisfaction** The majority of customers interviewed have been long term customers and know the utility very well. Of those, 96% of the customers interviewed had been using Chapleau PUC's services for more than 10 years. The customer relationships in this small community are extremely close and personable. Scheduled appointments were 100% on time. There is a high degree of satisfaction with Chapleau PUC. Customers are content, engaged and willing to share their positive experience with the utility often mentioning that Chapleau PUC is very "accommodating", "very nice to deal with" and "good on customer service'' There is a high degree of trust in Chapleau PUC. Again, 96% of the telephone calls were answered on time and in some instances the customers would simply "walk over and speak to Chapleau PUC employees directly". Generally customers feel that Chapleau PUC does a great job with what they have, considering the fact that the utility is embedded within Hydro One territory and some service interruptions relate to Hydro One issues. In terms of overall satisfaction, 45% of the customers ranked their service at 10 on the scale 1 to 10.	No action required - There are no customer needs and preferences idemtified.
	Billing and Price Sensitivity Notable customer concerns relate to billing and cost of power, which customers feel is unfairly high. Customers prefer to see, itemized on their bill, the percentage or the amount that is allocated to the province. Many of them, at the time of the interview, were unaware of the financial share directed to the province. - Price sensitivity can be easily distinguished through the customer feedback. Customers are concerned that "the bills doubled during the change from bi monthly to monthly billing" although things have evened for most of those interviewed. There was definite trend of discomfort that the utility share in the financial allocations is so small and accounting to the interviewed perceived as unfairly unequal, comparing to the share of the province. Despite the expectation that the cost of living in a remote place is high, seniors on fixed incomes have difficulty covering the bills and feel pressed to rent instead of owning a home so they could afford to stay in the community. Most of the interviewed were on a fixed income and face numerous challenges typical for a Northern Remote Community.	No action required - There are no customer needs and preferences idemtified.

	Safety Customers feel that Chapleau PUC sees safety as a number one priority and have noticed that Chapleau PUC employees are using proper safety protocols and safety gear on the job. Of those interviewed, 86% ranked the importance of safety demonstrated by the utility operations staff as 10 in the scale of 1 to 10.. Customers perceived utility employees as highly effective, skilled and commented about the excellent job they do. Many expressed that in small community like Chapleau “if they didn't’ feel that safety was a concern for Chapleau PUC, people would talk about it. “	No action required - There are no customer needs and preferences idemtified.
	Reliability Continuous, reliable power was, not surprisingly, the most important item for respondents. Customer perception in regard to power outages is that outages are predominantly very short term and do not affect their daily living. Of those interviewed, 58% have noticed fewer changes in the system reliability. Longer interruptions were experienced years ago. Customers are resilient in the challenges of the Northern Climate and have expressed strong knowledge in emergency preparedness measures like backup generators or wood stoves. People feel strongly that Chapleau PUC does their very best in any circumstances facing the challenges of a deteriorating distribution network and severe weather. Some customers felt that the distribution system of Hydro One is less reliable than the one managed by Chapleau PUC. Customers see CPUC as a community partner, and trust them completely (100%), as opposed to their lack of trust in Hydro One. This lack of trust and sense of powerlessness, in the face of huge Hydro One bureaucracy and the remoteness of their service support, was a common theme. People feel that reliable power, particularly in the north, is essential to daily life. In fact, 96% of the respondents ranked, as extremely high, the importance of taking action to improve the delivery of continuous reliable power.	No action required - There are no customer needs and preferences idemtified.
	Energy Conservation, Smart Meters and Green Button Initiative. Energy conservation was very strongly supported by 57% of the respondents, with some customers requesting special conservation education. The major interest is focused on renewables and overall measures for energy conservation; however, there is a substantial minority who feel that Chapleau PUC should predominantly concentrate efforts on distributing power. Some people (mainly seniors) felt that parents should be teaching their children how to conserve energy, but many others believe in investing in children’s energy education. Some also feel that they could use help and support in finding new ways to save energy, and, therefore, offset costs. Some people have the perception that the Smart Meters are taking care of energy conservation education, as they indirectly force them to conserve energy by shifting the use at a different time slots of the day in order to benefits from the preferential rates . Most respondents feel that they have shifted their load to the best of their ability and there is no room for improvement. The ones who haven’t changed their energy consumption schedules have difficulty in doing so due to their personal circumstances, related to shift work or health concerns. A full 100% of those interviewed are aware of the smart meter and what the smart meter does. There was little uptake for the Green Button Initiative that is currently being promoted by the Ministry of Energy. Customers are concerned that they don’t have time, don’t go on their computer enough, or, if they do go on their computer, they don’t have time to browse the website for information. Customers don’t see how the green button would help them, and the general perception if that they are already doing the most they can by shifting their load, thus, only a few customers will be taking advantage, if any applications are to be developed. This is consistent with the aging population in the area, reluctant to energy conservation analytics tools.	No action required - There are no customer needs and preferences idemtified.

	Community Energy Plan and Renewables Customers support renewables, and 44% plan to invest in renewable energy within the next 5 years. Many people felt that renewable energy is not only the way of the future, but also is a way to offset the cost of hydro power in their homes. Respondents expressed that they felt that Americans across the border were getting power at reduced cost or “cheaper” rates from Canadian resources, than people in Chapleau. Customers believe that local renewable energy would address this cost imbalance. There is a definite perception that the energy cost savings would offset the cost of installation. As the installation price and renewable equipment costs come down, particularly for solar panels, many people would consider, and are currently considering, installing these on their homes and businesses. The results of the survey suggest the need for a program to support renewable installations (such as a lease or financing program). This would generate a lot of community interest and uptake.	No action required - There are no customer needs and preferences idemtified.
	Communication A key recommendation from the majority of respondents was for Chapleau PUC to improve its communication on all levels. Communication is generally seen as less effective than it could be. People would like more information about things like electrical safety and energy conservation. Many customers do not understand the electricity sector, and, thus, do not understand the issues when they are presented to them in print. Almost all respondents expressed appreciation for the educational component of the survey, and felt that the opportunity to interactively conversing during the survey with the accompanied explanations, definitions and clarifications, had helped them better understand how “things work”. People mentioned that there is a fairly low literacy rate in Chapleau, which has been taken into account in communicating with customers and in the customer engagement process in the past. Some suggested simplifying the messages and providing them in different media, such as television, radio and even on the website, by using more visual cues and suggested more simplified promotional flyers when they are distributed in the mail with the bill. Customers expressed that they do not read the information provided in the bill as it is too dense and not easy to understand. This is seen as a missed opportunity. Respondents mentioned utility staff by name, expressing satisfaction by noting utility employees as “very accommodating” in explaining the challenges of power distribution in the north to the customers who approach her with questions.	The suggestions to simplifying the messages and providing them in different media, such as television, radio and even on the website, by using more visual cues and suggested more simplified promotional flyers when they are distributed in the mail with the bill. As a small Utility to provide these messages on television or radio can be very costly for a small utility having only about 2,300 residents. Chapleau PUC acknowleges their customer concerns regarding easier to understand customer education and is investigating its options for providing better educational material for them.
	Asset Management Plan (Distribution System Plan) During the customer survey, customers were provided 3 investment scenarios in the future of the distribution system versus a no investment. Investments in a new modern system, was supported by 87% of the respondents, even if this will cause a slight increase of the electricity rates. Some customers saw borrowing at the current low interest rates as appealing, as this would not impact rates. Keeping costs down was their primary concern, but maintaining the town's infrastructure reluctantly trumped cost concerns. The option of not making any investments was not supported.	No action required - There are no customer needs and preferences idemtified.
	Other Communication No further communication was sent to customers about the application.	

Note: Use "ALT-ENTER" to go to the next line within a cell

General Instructions to MIFRS Appendices
Types of Schedules to File

The purpose of this tab is to provide general instructions. The specific instructions to each appendix are listed in footnotes of each appendix.

The typical applicant is expected to have made capitalization and depreciation policy changes under CGAAP as permitted by the Board on January 1, 2012 or mandated by the Board by January 1, 2013, and adopted IFRS for reporting purposes on January 1, 2015 (transition date January 1, 2014). In general, applicants under the two scenarios should provide the following information in the appendices:

			Accounting Policy Changes in 2012 and Adopted IFRS in 2015	Accounting Policy Changes in 2013 and Adopted IFRS in 2015
			(Date of Transition to IFRS 2014)	
Information to be filed in 2016 CoS Application	2016	Test	MIFRS	MIFRS
	2015	Bridge	MIFRS	MIFRS
	2014	Historical	MIFRS and Revised CGAAP*	MIFRS and Revised CGAAP*
	2013	Historical	Revised CGAAP	CGAAP and Revised CGAAP
	2012	Historical	CGAAP and Revised CGAAP	CGAAP
	2011 and Prior	Historical	CGAAP	CGAAP

1) For the year that the applicant implemented changes to its capitalization and depreciation policies (2012 or 2013), the applicant must file two appendices, one before and one after the policy changes.

2) For the transition year (2014), the applicant may file two appendices, one under Revised CGAAP and one under MIFRS, depending on the materiality of impacts. See the specific instructions under each appendix below for further details.

Appendix 2-BA - Fixed Asset Schedule

Applicants are to provide Appendix 2-BA in accordance with the years and corresponding accounting standards noted in the above table to provide a year over year continuity in fixed assets. *For the transition year (2014), the applicant should file two appendices, one under Revised CGAAP and one under MIFRS if the change between Revised CGAAP and MIFRS is material. If the change from the accounting standards is not material, the applicant may choose to only provide one appendix under MIFRS. However, the applicant must also indicate the fixed asset net book value balance under Revised CGAAP, the total dollar value of the change and explain why it is not material.

Regulatory Gross Assets of Property, Plant and Equipment

For an applicant that adopted IFRS on January 1, 2015 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2013 regulatory gross assets of property, plant and equipment as the opening January 1, 2014 regulatory gross assets. The applicant must provide schedules (including Appendix 2-BA, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2013 regulatory gross assets of property, plant and equipment, by asset class; and
- January 1, 2014 regulatory gross assets of property, plant and equipment, by asset class.

Accumulated Depreciation

For an applicant that adopted IFRS on January 1, 2015 for financial reporting purposes, the applicant must establish the continuity of historic cost by using the December 31, 2013 regulatory accumulated depreciation as the opening January 1, 2014 regulatory accumulated depreciation. The applicant must provide schedules (including Appendix 2-BA, Fixed Asset Continuity Schedule) which must identify the following details to substantiate the continuity of historic cost for regulatory purposes:

- December 31, 2013 regulatory accumulated depreciation, by asset class; and
- January 1, 2014 regulatory accumulated depreciation, by asset class.

Appendix 2-C - Depreciation and Amortization

Applicants are to provide Appendix 2-C starting in the year capitalization and depreciation policy changes were implemented in accordance with the years and corresponding accounting standards listed in the above table. If an applicant changed capitalization and depreciation policies effective January 1, 2012 and adopted IFRS for reporting purposes effective January 1, 2015, the applicant must complete Appendix 2-CA to 2-CF (inclusive). If an applicant changed capitalization and depreciation policies effective January 1, 2013 and adopted IFRS for reporting purposes effective January 1, 2015, the applicant must complete Appendix 2-CG to 2-CK (inclusive). *Depreciation accounting policy changes were mandated by the Board by January 1, 2013. These accounting changes should be implemented consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards* (EB-2008-0408), the *Depreciation Study for Use by Electricity Distributors* (EB-2010-0178) and the Revised *2012 Accounting Procedures Handbook for Electricity Distributors*. In general, no further changes to an applicant's depreciation policy (i.e. assets' service lives) are expected after the Board mandated changes by January 1, 2013. The set of Appendix CA to CK assumes this to be the case. If the applicant has made any changes to its depreciation policy subsequent to the Board mandated changes, applicants must identify the change, explain the nature of the change, the reason for the change, quantify the impact of the change, and quantify the depreciation expense before and after the change.

Appendix 2-E - Account 1575, IFRS-CGAAP Transitional PP&E Amounts (2-EA), Account 1576, Accounting Changes Under CGAAP (2-EB, 2-EC)

If an applicant changed capitalization and depreciation policies effective January 1, 2012 and adopted IFRS for reporting purposes effective January 1, 2015, the applicant must complete Appendix 2-EA and 2-EB. If the applicant did not make any further PP&E accounting policy changes beyond the capitalization and depreciation policy changes as permitted by the Board on January 1, 2012 (i.e. no further changes made on transition to IFRS), the applicant must indicate this and does not need to complete Appendix 2-EA.

If an applicant changed capitalization and depreciation policies effective January 1, 2013 and adopted IFRS for reporting purposes effective January 1, 2015, the applicant must complete Appendix 2-EA and 2-EC. If the applicant did not make any further PP&E accounting policy changes beyond the capitalization and depreciation policy changes as mandated by the Board by January 1, 2013 (i.e. no further changes made on transition to IFRS), the applicant must indicate this and does not need to complete Appendix 2-EA.

Please refer to section 2.12.4 and 2.12.5 of the Filing Requirements for further details.

Appendix 2-YA - Summary of Impacts to Revenue Requirement from Transition to MIFRS

For applicants adopting MIFRS, the applicants must provide a summary of the dollar impacts of MIFRS to each component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall impact on the proposed revenue requirement. Accordingly, the applicants must identify financial differences and resulting revenue requirement impacts arising from the adoption of MIFRS as compared to CGAAP prior to capitalization and depreciation policy changes.

File Number:	EB-2015-0060
Exhibit:	2
Tab:	
Schedule:	
Page:	10
Date:	10-Aug-16

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Accounting Standard CGAAP
Year 2011

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 11,186			$ 11,186	-$ 9,544	-$ 903		-$ 10,447	$ 739
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 141			$ 141				$ -	$ 141
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 462,817			$ 462,817	-$ 205,611	-$ 10,288		-$ 215,899	$ 246,918
47	1820	Distribution Station Equipment <50 kV				$ -				$ -	$ -
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,120,455	$ 6,934		$ 1,127,389	-$ 807,400	-$ 12,620		-$ 820,020	$ 307,369
47	1835	Overhead Conductors & Devices				$ -				$ -	$ -
47	1840	Underground Conduit	$ 77,511			$ 77,511	-$ 50,441	-$ 1,083		-$ 51,524	$ 25,987
47	1845	Underground Conductors & Devices		$ 3,516		$ 3,516	$ -	-$ 70		-$ 70	$ 3,446
47	1850	Line Transformers	$ 388,667			$ 388,667	-$ 247,959	-$ 5,628		-$ 253,587	$ 135,080
47	1855	Services (Overhead & Underground)				$ -				$ -	$ -
47	1860	Meters	$ 174,647		-$ 146,546	$ 28,101	-$ 105,015	-$ 6,963	$ 99,219	-$ 12,759	$ 15,342
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 661			$ 661	-$ 445	-$ 119		-$ 564	$ 97
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment				$ -				$ -	$ -
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment				$ -				$ -	$ -
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment				$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue [5]									
						$ -				$ -	$ -
		Sub-Total	**$ 2,236,085**	**$ 10,450**	**-$ 146,546**	**$ 2,099,989**	**-$ 1,426,415**	**-$ 37,675**	**$ 99,219**	**-$ 1,364,871**	**$ 735,118**
		Less Socialized Renewable Energy Generation Investments **(input as negative)**				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets ***(input as negative)***				$ -				$ -	$ -
		Total PP&E	**$ 2,236,085**	**$ 10,450**	**-$ 146,546**	**$ 2,099,989**	**-$ 1,426,415**	**-$ 37,675**	**$ 99,219**	**-$ 1,364,871**	**$ 735,118**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									

		Total	**-$ 37,675**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 37,675

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	0
Exhibit:	4
Tab:	
Schedule:	
Page:	90
Date:	10-Aug-16

Appendix 2-BB
Service Life Comparison
Table F-1 from Kinetrics Report[1]

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles Towers and Fixtures	25	4%	45	2.22%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55								
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75								
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Trasformers	25	4%	40	2.5%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60								
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55	1815	Transformer Station Equipment	25	4%	40	2.5%	No	No
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60								
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60								
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90								
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40								
	32	Secondary Cables in Duct			35	40	60	1845	Underground Conductors and Devices	25	4%	40	2.5%	No	No
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45								
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70	1840	Underground Conduit	25	4%	40	2.5%	No	No
	37	UG Vaults	Overall		40	60	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45								
	40	Ducts			30	50	85								
	41	Concrete Encased Duct Banks			35	55	80								
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30								

Table F-2 from Kinetrics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15								
2	Vehicles	Trucks & Buckets	5	15								
		Trailers	5	20								
		Vans	5	10								
3	Administrative Buildings		50	75								
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75								
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	1.8183	55%	5	20.0%	No	No
		Software	2	5	1925	Computer Equipment - Software	1.8183	55%	5	20.0%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10								
		Tools, Shop, Garage Equipment	5	10								
		Measurement & Testing Equipment	5	10								
8	Communication	Towers	60	70								
		Wireless	2	10								
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35								
11	Wholesale Energy Meters		15	30	1860	Meters	10	10%	15	6.67%	No	No
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Smart Meters	10	10%	15	6.67%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

*** TS & MS = Transformer and Municipal Stations UG = Underground Systems S = Monitoring and Control Systems**

Note 1: Tables F-1 and F-2 above are to be used as a reference in order to complete columns J, K, L and N.
See pages 17-19 of Kinetrics Report

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-CA
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

Year 2012 Former CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation [1] (e) = (c) + ½ x (d)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)			$ -		$ -		0.00%	$ -		$ -
1612	Land Rights (Formally known as Account 1906)			$ -		$ -		0.00%	$ -		$ -
1805	Land			$ -		$ -		0.00%	$ -		$ -
1808	Buildings			$ -		$ -		0.00%	$ -		$ -
1810	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			$ -		$ -		0.00%	$ -		$ -
1820	Distribution Station Equipment <50 kV			$ -		$ -		0.00%	$ -		$ -
1825	Storage Battery Equipment			$ -		$ -		0.00%	$ -		$ -
1830	Poles, Towers & Fixtures			$ -		$ -		0.00%	$ -		$ -
1835	Overhead Conductors & Devices			$ -		$ -		0.00%	$ -		$ -
1840	Underground Conduit			$ -		$ -		0.00%	$ -		$ -
1845	Underground Conductors & Devices			$ -		$ -		0.00%	$ -		$ -
1850	Line Transformers			$ -		$ -		0.00%	$ -		$ -
1855	Services (Overhead & Underground)			$ -		$ -		0.00%	$ -		$ -
1860	Meters			$ -		$ -		0.00%	$ -		$ -
1860	Meters (Smart Meters)			$ -		$ -		0.00%	$ -		$ -
1905	Land			$ -		$ -		0.00%	$ -		$ -
1908	Buildings & Fixtures			$ -		$ -		0.00%	$ -		$ -
1910	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (5 years)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equipment - Hardware			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment			$ -		$ -		0.00%	$ -		$ -
1935	Stores Equipment			$ -		$ -		0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment			$ -		$ -		0.00%	$ -		$ -
1945	Measurement & Testing Equipment			$ -		$ -		0.00%	$ -		$ -
1950	Power Operated Equipment			$ -		$ -		0.00%	$ -		$ -
1955	Communications Equipment			$ -		$ -		0.00%	$ -		$ -
1955	Communication Equipment (Smart Meters)			$ -		$ -		0.00%	$ -		$ -
1960	Miscellaneous Equipment			$ -		$ -		0.00%	$ -		$ -
1970	Load Management Controls Customer Premises			$ -		$ -		0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			$ -		$ -		0.00%	$ -		$ -
1980	System Supervisor Equipment			$ -		$ -		0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets			$ -		$ -		0.00%	$ -		$ -
1990	Other Tangible Property			$ -		$ -		0.00%	$ -		$ -
1995	Contributions & Grants			$ -		$ -		0.00%	$ -		$ -
	Total	**$ -**	**$ -**	$ -	$ -	$ -			$ -	$ -	$ -

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-CB
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

Year 2012 Revised CGAAP

Account	Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1612	Land Rights (Formally known as Account 1906)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1805	Land					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1808	Buildings					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1810	Leasehold Improvements					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1835	Overhead Conductors & Devices					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1840	Underground Conduit					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1845	Underground Conductors & Devices					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1850	Line Transformers					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1855	Services (Overhead & Underground)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1860	Meters					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1860	Meters (Smart Meters)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1905	Land					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1910	Leasehold Improvements					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (5 years)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1930	Transportation Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1935	Stores Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1945	Measurement & Testing Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1950	Power Operated Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communications Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1970	Load Management Controls Customer Premises					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1990	Other Tangible Property					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1995	Contributions & Grants					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	$ -	$ -				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

3 The applicant should ensure that the years for new additions of assets are the asset useful lives determined by management in accordance with the Board's regulatory accounting policies. The capitalization and depreciation expense accounting changes should be implemented consistent with the Board's regulatory accounting policies as set out for modified IFRS as contained in the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, the Kinectrics Report, and the Revised 2012 Accounting Procedures Handbook for Electricity Distributors ("APH").

4 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding 2012 additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1, 2012, the effective date of the changes in policies, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as of January 1, 2012. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the

5 NBV must exclude assets still on the books but which have been fully amortized or depreciated.

6 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-CC
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

2013 Revised CGAAP

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2013 Depreciation Expense [1] (h)=2012 Full Year Deprecation + ((d)*0.5)/(f)	2013 Depreciation Expense per Apppendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [3] (p) = 2012 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ -		$ -	$ -		$ -
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land			0.00%	$ -		$ -	$ -		$ -
1808	Buildings			0.00%	$ -		$ -	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment			0.00%	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures			0.00%	$ -		$ -	$ -		$ -
1835	Overhead Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1840	Underground Conduit			0.00%	$ -		$ -	$ -		$ -
1845	Underground Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1850	Line Transformers			0.00%	$ -		$ -	$ -		$ -
1855	Services (Overhead & Underground)			0.00%	$ -		$ -	$ -		$ -
1860	Meters			0.00%	$ -		$ -	$ -		$ -
1860	Meters (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1905	Land			0.00%	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -	$ -		$ -
1970	Load Management Controls Customer Premises			0.00%	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -	$ -		$ -
	Total	$ -			$ -	$ -	$ -	$ -	$ -	$ -

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

3 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-CD
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

2014 MIFRS

Account	**Description**	**Additions** (d)	**Years (new additions only)** (f)	**Depreciation Rate on New Additions** (g) = 1 / (f)	**2014 Depreciation Expense [1]** (h)=2013 Full Year Deprecation + ((d)*0.5)/(f)	**2014 Depreciation Expense per Apppendix 2-BA Fixed Assets, Column J** (l)	**Variance [2]** (m) = (h) - (l)	**Depreciation Expense on 2014 Full Year Additions** (n)=((d))/(f)	**Less Depreciation Expense on Assets Fully Depreciated during the year** (o)	**2014 Full Year Depreciation [3]** (p) = 2013 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ -		$ -	$ -		$ -
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land			0.00%	$ -		$ -	$ -		$ -
1808	Buildings			0.00%	$ -		$ -	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment			0.00%	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures			0.00%	$ -		$ -	$ -		$ -
1835	Overhead Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1840	Underground Conduit			0.00%	$ -		$ -	$ -		$ -
1845	Underground Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1850	Line Transformers			0.00%	$ -		$ -	$ -		$ -
1855	Services (Overhead & Underground)			0.00%	$ -		$ -	$ -		$ -
1860	Meters			0.00%	$ -		$ -	$ -		$ -
1860	Meters (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1905	Land			0.00%	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -	$ -		$ -
1970	Load Management Controls Customer Premises			0.00%	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -	$ -		$ -
	Total	**$ -**			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)									
	Total Depreciation Expense				**$ -**					

Notes:

1. Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
2. The applicant must provide an explanation of material variances in evidence.
3. This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

2015 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2015 Depreciation Expense [1] (h)=2014 Full Year Depreciation + ((d)*0.5)/(f)	2015 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2015 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2015 Full Year Depreciation [3] (p) = 2014 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ -		$ -	$ -		$ -
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land			0.00%	$ -		$ -	$ -		$ -
1808	Buildings			0.00%	$ -		$ -	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment			0.00%	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures			0.00%	$ -		$ -	$ -		$ -
1835	Overhead Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1840	Underground Conduit			0.00%	$ -		$ -	$ -		$ -
1845	Underground Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1850	Line Transformers			0.00%	$ -		$ -	$ -		$ -
1855	Services (Overhead & Underground)			0.00%	$ -		$ -	$ -		$ -
1860	Meters			0.00%	$ -		$ -	$ -		$ -
1860	Meters (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1905	Land			0.00%	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -	$ -		$ -
1970	Load Management Controls Customer Premises			0.00%	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -	$ -		$ -
	Total	$ -			$ -	$ -	$ -	$ -	$ -	$ -
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)									
	Total Depreciation expense to be included in the test year revenue requirement				$ -					

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

3 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-CF
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

2016 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2016 Depreciation Expense [1] (h)=2015 Full Year Depreciation + ((d)*0.5)/(f)	2016 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (I)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ -		$ -
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -
1805	Land			0.00%	$ -		$ -
1808	Buildings			0.00%	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ -		$ -
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -
1825	Storage Battery Equipment			0.00%	$ -		$ -
1830	Poles, Towers & Fixtures			0.00%	$ -		$ -
1835	Overhead Conductors & Devices			0.00%	$ -		$ -
1840	Underground Conduit			0.00%	$ -		$ -
1845	Underground Conductors & Devices			0.00%	$ -		$ -
1850	Line Transformers			0.00%	$ -		$ -
1855	Services (Overhead & Underground)			0.00%	$ -		$ -
1860	Meters			0.00%	$ -		$ -
1860	Meters (Smart Meters)			0.00%	$ -		$ -
1905	Land			0.00%	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -
1970	Load Management Controls Customer Premises			0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -
	Total	$ -			$ -	$ -	$ -
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)						
	Total Depreciation expense to be included in the test year revenue requirement				$ -		

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	
Date:	10-Aug-16

Appendix 2-CG
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

Year 2013 Former CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation [1] (e) = (c) + ½ x (d)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	2013 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 42,003		$ 42,003	$ 40,000	$ 62,003	1.82	55.00%	$ 34,099	$ 34,101	-$ 2
1612	Land Rights (Formally known as Account 1906)			$ -		$ -		0.00%	$ -		$ -
1805	Land	$ 141		$ 141		$ 141		0.00%	$ -	$ -	$ -
1808	Buildings			$ -		$ -		0.00%	$ -		$ -
1810	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 252,139		$ 252,139	$ 34,700	$ 269,489	25.00	4.00%	$ 10,780	$ 12,127	-$ 1,347
1820	Distribution Station Equipment <50 kV			$ -		$ -		0.00%	$ -		$ -
1825	Storage Battery Equipment			$ -		$ -		0.00%	$ -		$ -
1830	Poles, Towers & Fixtures	$ 297,529		$ 297,529	$ 8,956	$ 302,007	25.00	4.00%	$ 12,080	$ 12,120	-$ 40
1835	Overhead Conductors & Devices			$ -		$ -		0.00%	$ -		$ -
1840	Underground Conduit	$ 24,949		$ 24,949		$ 24,949	25.00	4.00%	$ 998	$ 998	$ 0
1845	Underground Conductors & Devices	$ 3,308		$ 3,308		$ 3,308	25.00	4.00%	$ 132	$ 132	$ 0
1850	Line Transformers	$ 134,029		$ 134,029	$ 3,691	$ 135,875	25.00	4.00%	$ 5,435	$ 5,435	$ 0
1855	Services (Overhead & Underground)			$ -		$ -		0.00%	$ -		$ -
1860	Meters	$ 10,128		$ 10,128	$ 193	$ 10,225	10.00	10.00%	$ 1,022	$ 1,022	-$ 0
1860	Meters (Smart Meters)	$ 318,999		$ 318,999	$ 687	$ 319,343	10.00	10.00%	$ 31,934	$ 31,866	$ 69
1905	Land			$ -		$ -		0.00%	$ -		$ -
1908	Buildings & Fixtures			$ -		$ -		0.00%	$ -		$ -
1910	Leasehold Improvements			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)			$ -		$ -		0.00%	$ -		$ -
1915	Office Furniture & Equipment (5 years)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equipment - Hardware	$ 44		$ 44		$ 44	1.82	55.00%	$ 24	$ 24	$ 0
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -		0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -		0.00%	$ -		$ -
1930	Transportation Equipment			$ -		$ -		0.00%	$ -		$ -
1935	Stores Equipment			$ -		$ -		0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment			$ -		$ -		0.00%	$ -		$ -
1945	Measurement & Testing Equipment			$ -		$ -		0.00%	$ -		$ -
1950	Power Operated Equipment			$ -		$ -		0.00%	$ -		$ -
1955	Communications Equipment			$ -		$ -		0.00%	$ -		$ -
1955	Communication Equipment (Smart Meters)			$ -		$ -		0.00%	$ -		$ -
1960	Miscellaneous Equipment			$ -		$ -		0.00%	$ -		$ -
1970	Load Management Controls - Customer Premises			$ -		$ -		0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			$ -		$ -		0.00%	$ -		$ -
1980	System Supervisor Equipment			$ -		$ -		0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets			$ -		$ -		0.00%	$ -		$ -
1990	Other Tangible Property			$ -		$ -		0.00%	$ -		$ -
1995	Contributions & Grants			$ -		$ -		0.00%	$ -		$ -
	Total	$ 1,083,269	$ -	$ 1,083,269	$ 88,227	$ 1,127,383			$ 96,505	$ 97,825	-$ 1,320

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

General **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	83
Date:	10-Aug-16

Appendix 2-CH
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

Year 2013 Revised CGAAP

Account	Description	Opening NBV as at Jan 1, 2013 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2013 Full Year Additions (n) = (d)/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2013 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 42,003	$ 40,000	4.29	5.00	20.00%	$ 9,791	$ 4,000	$ 13,791	$ 12,401	$ 1,390	$ 8,000	$ -	$ 17,791
1612	Land Rights (Formally known as Account 1906)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1805	Land	$ 141				0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1808	Buildings					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1810	Leasehold Improvements					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ 252,139	$ 34,700	28.18	40.00	2.50%	$ 8,947	$ 434	$ 9,381	$ 6,737	$ 2,644	$ 868		$ 9,815
1820	Distribution Station Equipment <50 kV					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 297,529	$ 8,956	32.72	45.00	2.22%	$ 9,093	$ 100	$ 9,193	$ 6,080	$ 3,113	$ 199		$ 9,292
1835	Overhead Conductors & Devices					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1840	Underground Conduit	$ 24,949		23.05	40.00	2.50%	$ 1,082	$ -	$ 1,082	$ 499	$ 583	$ -		$ 1,082
1845	Underground Conductors & Devices	$ 3,308		38.53	40.00	2.50%	$ 86	$ -	$ 86	$ 66	$ 20	$ -		$ 86
1850	Line Transformers	$ 134,027	$ 3,691	29.02	40.00	2.50%	$ 4,618	$ 46	$ 4,665	$ 2,717	$ 1,947	$ 92		$ 4,711
1855	Services (Overhead & Underground)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1860	Meters	$ 10,128	$ 193	8.47	15.00	6.67%	$ 1,196	$ 6	$ 1,202	$ 511	$ 691	$ 13		$ 1,209
1860	Meters (Smart Meters)	$ 318,999	$ 687	13.37	15.00	6.67%	$ 23,859	$ 23	$ 23,882	$ 21,289	$ 2,593	$ 46		$ 23,905
1905	Land					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1910	Leasehold Improvements					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (5 years)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 44		3.30	5.00	20.00%	$ 13	$ -	$ 13	$ 9	$ 5	$ -		$ 13
1920	Computer Equip.-Hardware(Post Mar. 22/04)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1930	Transportation Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1935	Stores Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1945	Measurement & Testing Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1950	Power Operated Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communications Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1970	Load Management Controls - Customer Premises					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1990	Other Tangible Property					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1995	Contributions & Grants					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total	**$ 1,083,265**	**$ 88,227**				**$ 58,686**	**$ 4,609**	**$ 63,295**	**$ 50,309**	**$ 12,986**	**$ 9,217**	**$ -**	**$ 67,904**

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

3 The applicant should ensure that the years for new additions of assets are the asset useful lives determined by management in accordance with the Board's regulatory accounting policies. The capitalization and depreciation expense accounting changes should be implemented consistent with the Board's regulatory accounting policies as set out for MIFRS as contained in the Report of the Board, Transition to International Financial Reporting Standards, EB-2008-0408, the Kinectrics Report, and the Revised 2012 Accounting Procedures Handbook for Electricity Distributors.

4 A recalculation should be performed to determine the average remaining life of opening balance of assets (i.e. excluding 2013 additions) under the change in policies under CGAAP. For example, Asset A had a useful life of 20 years under CGAAP without the change in policies. On January 1, 2013, the effective date of the changes in policies, Asset A was 3 years depreciated. As a result, Asset A would have a remaining service life of 17 years (20 years less 3 years) as of January 1, 2013. Due to making the change in policies under CGAAP, management re-assessed the asset useful lives and concluded that the revised useful life of Asset A is now 30 years. Therefore, the average remaining useful life of the opening balance of Asset A is determined to be 27 years (30 years less 3 years) under the revised CGAAP as of January 1, 2013.

5 NBV must exclude assets still on the books but which have been fully amortized or depreciated.

6 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	83
Date:	10-Aug-16

Appendix 2-CI
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

2014 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2014 Depreciation Expense [1] (h)=2013 Full Year Deprecation + ((d)*0.5)/(f)	2014 Depreciation Expense per Apppendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2014 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2014 Full Year Depreciation [3] (p) = 2013 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)	$ 25,000	5.00	20.00%	$ 20,291	$ 16,420	$ 3,870	$ 5,000		$ 22,791
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land			0.00%	$ -		$ -	$ -		$ -
1808	Buildings			0.00%	$ -		$ -	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ 9,815	$ 8,403	$ 1,412	$ -		$ 9,815
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment			0.00%	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 13,973	45.00	2.22%	$ 9,447	$ 6,148	$ 3,300	$ 311		$ 9,603
1835	Overhead Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1840	Underground Conduit			0.00%	$ 1,082	$ 489	$ 593	$ -		$ 1,082
1845	Underground Conductors & Devices			0.00%	$ 86	$ 65	$ 21	$ -		$ 86
1850	Line Transformers	$ 4,950	40.00	2.50%	$ 4,773	$ 2,750	$ 2,023	$ 124		$ 4,834
1855	Services (Overhead & Underground)			0.00%	$ -		$ -	$ -		$ -
1860	Meters			0.00%	$ 1,209	$ 490	$ 718	$ -		$ 1,209
1860	Meters (Smart Meters)			0.00%	$ 23,905	$ 20,889	$ 3,016	$ -		$ 23,905
1905	Land			0.00%	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ 13	$ 7	$ 6	$ -		$ 13
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -	$ -		$ -
1970	Load Management Controls - Customer Premises			0.00%	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -	$ -		$ -
	Total	**$ 43,923**			**$ 70,621**	**$ 55,661**	**$ 14,960**	**$ 5,434**	**$ -**	**$ 73,338**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)									
	Total Depreciation Expense				**$ 70,621**					

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

3 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	83
Date:	10-Aug-16

Appendix 2-CJ
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

2015 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2015 Depreciation Expense [1] (h)=2014 Full Year Depreciation + ((d)*0.5)/(f)	2015 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)	Depreciation Expense on 2015 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2015 Full Year Depreciation [3] (p) = 2014 Full Year Depreciation + (n) - (o)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ 22,791	$ 15,636	$ 7,154	$ -		$ 22,791
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -	$ -		$ -
1805	Land			0.00%	$ -		$ -	$ -		$ -
1808	Buildings			0.00%	$ -		$ -	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ 9,815	$ 6,792	$ 3,022	$ -		$ 9,815
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -	$ -		$ -
1825	Storage Battery Equipment			0.00%	$ -		$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 35,271	45.00	2.22%	$ 9,995	$ 7,234	$ 2,760	$ 784		$ 10,387
1835	Overhead Conductors & Devices			0.00%	$ -		$ -	$ -		$ -
1840	Underground Conduit			0.00%	$ 1,082	$ 599	$ 483	$ -		$ 1,082
1845	Underground Conductors & Devices			0.00%	$ 86	$ 79	$ 6	$ -		$ 86
1850	Line Transformers	$ 6,228	40.00	2.50%	$ 4,912	$ 3,508	$ 1,404	$ 156		$ 4,990
1855	Services (Overhead & Underground)			0.00%	$ -		$ -	$ -		$ -
1860	Meters			0.00%	$ 1,209	$ 622	$ 587	$ -		$ 1,209
1860	Meters (Smart Meters)			0.00%	$ 23,905	$ 18,510	$ 5,395	$ -		$ 23,905
1905	Land			0.00%	$ -		$ -	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ 13	$ 6	$ 8	$ -		$ 13
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -	$ -		$ -
1970	Load Management Controls - Customer Premises			0.00%	$ -		$ -	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -	$ -		$ -
	Total	**$ 41,499**			**$ 73,808**	**$ 52,986**	**$ 20,822**	**$ 940**	**$ -**	**$ 74,278**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)									
	Total Depreciation expense to be included in the test year revenue requirement				**$ 73,808**					

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

3 This column refers to the calculated full year depreciation but excludes the depreciation expense on assets fully depreciated during the year. This column is used for the purpose of calculating depreciation expense in the following year on the next worksheet.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	83
Date:	10-Aug-16

Appendix 2-CK
Depreciation and Amortization Expense

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013 and has adopted IFRS for financial reporting purposes effective January 1, 2015.

2016 MIFRS

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	2016 Depreciation Expense [1] (h)=2015 Full Year Depreciation + ((d)*0.5)/(f)	2016 Depreciation Expense per Appendix 2-BA Fixed Assets, Column J (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)			0.00%	$ 22,791	$ 12,509	$ 10,282
1612	Land Rights (Formally known as Account 1906)			0.00%	$ -		$ -
1805	Land			0.00%	$ -		$ -
1808	Buildings			0.00%	$ -		$ -
1810	Leasehold Improvements			0.00%	$ -		$ -
2055	Construction Work-in-Progress -Substation	$ 785,000	40.00	2.50%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV			0.00%	$ 9,815	$ 6,623	$ 3,192
1820	Distribution Station Equipment <50 kV			0.00%	$ -		$ -
1825	Storage Battery Equipment			0.00%	$ -		$ -
1830	Poles, Towers & Fixtures	$ 35,314	45.00	2.22%	$ 10,779	$ 8,563	$ 2,216
1835	Overhead Conductors & Devices			0.00%	$ -		$ -
1840	Underground Conduit			0.00%	$ 1,082	$ 584	$ 498
1845	Underground Conductors & Devices			0.00%	$ 86	$ 62	$ 24
1850	Line Transformers	$ 2,350	40.00	2.50%	$ 5,020	$ 3,586	$ 1,433
1855	Services (Overhead & Underground)			0.00%	$ -		$ -
1860	Meters			0.00%	$ 1,209	$ 580	$ 628
1860	Meters (Smart Meters)			0.00%	$ 23,905	$ 17,275	$ 6,630
1905	Land			0.00%	$ -		$ -
1908	Buildings & Fixtures			0.00%	$ -		$ -
1910	Leasehold Improvements			0.00%	$ -		$ -
1915	Office Furniture & Equipment (10 years)			0.00%	$ -		$ -
1915	Office Furniture & Equipment (5 years)			0.00%	$ -		$ -
1920	Computer Equipment - Hardware			0.00%	$ 13	$ 4	$ 9
1920	Computer Equip.-Hardware(Post Mar. 22/04)			0.00%	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			0.00%	$ -		$ -
1930	Transportation Equipment			0.00%	$ -		$ -
1935	Stores Equipment			0.00%	$ -		$ -
1940	Tools, Shop & Garage Equipment			0.00%	$ -		$ -
1945	Measurement & Testing Equipment			0.00%	$ -		$ -
1950	Power Operated Equipment			0.00%	$ -		$ -
1955	Communications Equipment			0.00%	$ -		$ -
1955	Communication Equipment (Smart Meters)			0.00%	$ -		$ -
1960	Miscellaneous Equipment			0.00%	$ -		$ -
1970	Load Management Controls - Customer Premises			0.00%	$ -		$ -
1975	Load Management Controls Utility Premises			0.00%	$ -		$ -
1980	System Supervisor Equipment			0.00%	$ -		$ -
1985	Miscellaneous Fixed Assets			0.00%	$ -		$ -
1990	Other Tangible Property			0.00%	$ -		$ -
1995	Contributions & Grants			0.00%	$ -		$ -
	Total	**$ 822,664**			**$ 74,699**	**$ 49,787**	**$ 24,912**
	Depreciation exp. adj. from gain or loss on the retirement of assets (pool of like assets)						
	Total Depreciation expense to be included in the test year revenue requirement				**$ 74,699**		

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.

2 The applicant must provide an explanation of material variances in evidence.

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	**2012 Historical Year**	**2013 Historical Year**	**2014 Historical Year**	**2015 Bridge Year**	**2016 Test Year**
CHAPLEAU PUC DOES NOT APPLY OVERHEAD EXPENSE TO CAPITALIZATION - ALL OM&A COSTS ARE UNCAPITALIZED					
Total OM&A Before Capitalization (B)	$ -	$ -	$ -	$ -	$ -

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	**2012 Historical Year**	**2013 Historical Year**	**2014 Historical Year**	**2015 Bridge Year**	**2016 Test Year**	**Directly Attributable? (Y/N)**	**Explanation for Change in Overhead Capitalized**
employee benefits							
costs of site preparation							
initial delivery and handling costs							
costs of testing whether the asset is functioning properly							
professional fees							
costs of opening a new facility							
costs of introducing a new product or service (including costs of advertising and promotional activities)							
costs of conducting business in a new location or with a new class of customer (including costs of staff training)	CHAPLEAU PUC DOES NOT APPLY OVERHEAD EXPENSE TO CAPITALIZATION - ALL OM&A COSTS ARE UNCAPITALIZED						
administration and other general overhead costs							
Insert description of additional item(s) and new rows if needed							
Total Capitalized OM&A (A)	$ -	$ -	$ -	$ -	$ -		
% of Capitalized OM&A (=A/B)	0%	0%	0%	0%	0%		

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-EA
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts
2015 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopted IFRS on January 1, 2015 for financial reporting purposes

	2012 Rebasing Year	2012	2013	2014	2015	2016 Rebasing Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
				$	$	
PP&E Values under CGAAP						
Opening net PP&E - Note 1					0	
Net Additions - Note 4						
Net Depreciation (amounts should be negative) - Note 4						
Closing net PP&E (1)				0	0	
PP&E Values under MIFRS (Starts from 2014, the transition year)						
Opening net PP&E - Note 1					0	
Net Additions - Note 4						
Net Depreciation (amounts should be negative) - Note 4						
Closing net PP&E (2)				0	0	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				0	0	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-
Amount included in Deferral and Variance Account Rate Rider Calculation	-

WACC	
# of years of rate rider disposition period	

Notes:

1 For an applicant that adopted IFRS on January 1, 2015, the PP&E values as of January 1, 2014 under both CGAAP and MIFRS should be the same.

2 Return on rate base associated with deferred balance is calculated as:

the deferral account closing balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 The PP&E deferral account is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-EB
Account 1576 - Accounting Changes under CGAAP
2012 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

	2012 Rebasing Year	2012	2013	2014	2015	2016 Rebasing Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
		$	$	$	$	
PP&E Values under former CGAAP						
Opening net PP&E - Note 1			0	0	0	
Net Additions - Note 4						
Net Depreciation (amounts should be negative) - Note 4						
Closing net PP&E (1)		0	0	0	0	
PP&E Values under revised CGAAP (Starts from 2012)						
Opening net PP&E - Note 1			0	0	0	
Net Additions - Note 4						
Net Depreciation (amounts should be negative) - Note 4						
Closing net PP&E (2)		0	0	0	0	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP		0	0	0	0	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	**WACC**	
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	**# of years of rate rider disposition period**	
Amount included in Deferral and Variance Account Rate Rider Calculation	-		

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2012, the PP&E values as of January 1, 2012 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:

the variance account ending balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

File Number:	EB-2015-0060
Exhibit:	9
Tab:	
Schedule:	
Page:	7
Date:	10-Aug-16

Appendix 2-EC
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

For applicants that made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2012 Rebasing Year	2012	2013	2014	2015	2016 Rebasing Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS
	Forecast	Actual	Actual	Actual	Forecast	Forecast
			$	$	$	
PP&E Values under former CGAAP						
Opening net PP&E - Note 1			1,083,265	1,073,667	1,021,342	
Net Additions - Note 4			88,227	43,923	41,499	
Net Depreciation (amounts should be negative) - Note 4			-97,825	-96,248	-77,905	
Closing net PP&E (1)			1,073,667	1,021,342	984,936	
PP&E Values under revised CGAAP (Starts from 2012)						
Opening net PP&E - Note 1			1,083,265	1,121,183	1,109,445	
Net Additions - Note 4			88,227	43,923	41,499	
Net Depreciation (amounts should be negative) - Note 4			-50,309	-55,661	-52,986	
Closing net PP&E (2)			1,121,183	1,109,445	1,097,958	
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			-47,516	-88,103	-113,022	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	113,022
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	7,098
Amount included in Deferral and Variance Account Rate Rider Calculation	-	120,120

WACC	6.28%
# of years of rate rider disposition period	1

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, the PP&E values as of January 1, 2013 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:

the variance account ending balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-FA
Renewable Generation Connection Investment Summary (past investments or over the future rate setting period)

Enter the details of the Renewable Generation Connection projects as described in the appropriate section of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.
For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (EB-2009-0349, 6-10-2010, p. 15, note 9)

There are two scenarios described below. Separate sets of spreadsheets (2-FA, 2-FB, 2-FC) should be submited for each scenario as required.
Scenario 1: **Past Investments with No Recovery.** The distributor has made investments in the past (during the IRM Years), but has not received approval for these projects and therefore did not receive revenue from the IESO under Regulation 330/09 and did not receive ratepayer revenue for the direct benefit portion of the investment.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's last Cost of Service approval.
The Direct Benefit portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the distributor's ratepayers through a rate rider.
The Provincial Recovery portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the IESO through a separate order.

Scenario 2: **Investments in the Test Year and Beyond.** Distributor plans to make investments in 2016 and/or beyond. These investments should be added to 2-FA in the appropriate year.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's current application.

Part A

					Test Year				
REI Investments (Direct Benefit at 6%)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Project 1									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5									
Name: REI Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Part B

					Test Year				
Expansion Investments (Direct Benefit at 17%)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Project 1									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5									
Name: Expansion Connection Project									
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2016 and beyond, enter variables as in the application.
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

	2012			2013			2014		
	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -

	2015			2016 Test Year			2017		
	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -

	2018			2019			2020		
	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2012		2013		2014		2015	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tax Rate (to be entered)								
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Up								
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	2016		2017		2018			2019			2020	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
							Total			Total		
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Amortization (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
CCA (6% DB and 94% P)	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Tax Rate (to be entered)												
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Gross Up												
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -	$ -

		2012	2013	2014	2015	2016	2017	2018	2019	2020
Net Fixed Assets										
Enter applicable amortization in years:	25									
Opening Gross Fixed Assets			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Year Amortization (before additions)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions (half year)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation

		2012	2013	2014	2015	2016	2017	2018	2019	2020
Opening UCC			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables for your last cost of service test year. For 2016 and beyond, enter variables as in the application.
Rate Riders are not calculated for Test Year as these assets and costs are already in the distributor's rate base.

	2012			2013			2014			2015		
	Total	Direct Benefi 17%	Provincial 83%	Total	Direct Benefi 17%	Provincial 83%	Total	Direct Benefi 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -			$ -

	2016 TEST YEAR			2017			2018			2019			2020		
	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -		$0	$ -		$0	$ -		$0	$ -		$0	$ -	
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
WCA		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ROE		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -			$ -			$ -

Note 1: The difference between the actual costs of approved eligible investments and revenue received from the IESO should be recorded in a variance account. The Board may provide regulatory accounting guidance regarding a variance account either in an individual proceeding or on a generic basis.
Note 2: For the 2016 Test Year, Costs and Revenues of the Direct Benefit are to be included in the test year applicant Rate Base and Revenues.

PILs Calculation

	2012		2013		2014		2015		2016 TEST YEAR		2017		2018		2019		2020	
Income Tax	Direct Benefi	Provincial	Direct Benefi	Provincial	Direct Benefi	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial
													Total		Total		Total	
Net Income - ROE on Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization (17% DB and 83% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA (17% DB and 83% P)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxable income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tax Rate (to be entered)																		
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Up																		
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed Up PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets

		2011	2012	2013	2014	2015	2016	2017	2018	2019
Enter applicable amortization in years:	25									
Opening Gross Fixed Assets			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Capital Additions		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Gross Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Accumulated Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Current Year Amortization (before additions)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Additions (half year)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Accumulated Amortization		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Opening Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC for PILs Calculation

		2014	2014	2014	2014	2015	2016	2017	2018	2019
Opening UCC			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions (from Appendix 2-FA)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
UCC Before Half Year Rule		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class (to be entered)	47	47	47	47	47	47	47	47	47	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

File Number:	EB-2015-0060
Exhibit:	2
Tab:	
Schedule:	
Page:	51
Date:	10-Aug-16

Appendix 2-G
Service Reliability Indicators
2010 - 2014

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply				
	2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
SAIDI	101.680	2.630	0.440	2.320	5.090	1.980	1.930	0.440	2.180	0.280
SAIFI	3.250	2.450	0.280	2.850	2.460	0.920	0.450	0.280	2.580	0.380

5 Year Historical Average

SAIDI		22.432		1.362
SAIFI		2.258		0.922

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Indicator	OEB Minimum Standard	2010	2011	2012	2013	2014
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	N/A	N/A	N/A	N/A	N/A
Telephone Accessibility	65.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Appointments Met	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	N/A	N/A	N/A	N/A	N/A
Telephone Call Abandon Rate	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Appointment Scheduling	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

File Number:	EB-2015-0060
Exhibit:	3
Tab:	
Schedule:	
Page:	25
Date:	10-Aug-16

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2011 Actual	2012 Actual	2013 Actual²	2014 Actual	Actual Year²	Bridge Year²	Test Year
		2008	2011	2013	2014	2014	2015	2016
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
4235	Specific Service Charges	$ 8,501	$ 8,156	$ 6,985	$ 9,142	$ 9,142	$ 7,545	$ 8,055
4225	Late Payment Charges	$ 5,583	$ 5,624	$ 7,192	$ 7,546	$ 7,546	$ 6,757	$ 6,500
4082	Retail Services Revenues	$ 2,834	$ 3,061	$ 3,009	$ 2,763	$ 2,763	$ 2,444	$ 2,300
4405	Interest & Dividend Income	$ 18,370	$ 14,509	$ 8,952	$ 14,074	$ 14,074	$ 11,757	$ 13,200
4210	Rent From Electric Property	$ 7,306	$ 9,150	$ 12,234	$ 13,519	$ 13,519	$ 13,519	$ 13,450
4325/4330	Revenue & Expense of Merchandising	-$ 1,126	-$ 652	-$ 892	$ 6,121	$ 6,121	$ -	$ -
Specific Service Charges		$ 8,501	$ 8,156	$ 6,985	$ 9,142	$ 9,142	$ 7,545	$ 8,055
Late Payment Charges		$ 5,583	$ 5,624	$ 7,192	$ 7,546	$ 7,546	$ 6,757	$ 6,500
Other Operating Revenues		$ 10,140	$ 12,210	$ 15,243	$ 16,282	$ 16,282	$ 15,963	$ 15,750
Other Income or Deductions		$ 17,244	$ 13,857	$ 8,060	$ 20,196	$ 20,196	$ 11,757	$ 13,200
Total		$ 41,468	$ 39,847	$ 37,481	$ 53,165	$ 53,165	$ 42,022	$ 43,505

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4405 - Interest and Dividend Income

	2011 Actual	2012 Actual	2013 Actual²	2014 Actual	Actual Year²	Bridge Year²	Test Year
				2014	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Short-term Investment Interest	$ 10,467	$ 5,494	$ 4,840	$ 10,262	$ 10,262	$ 8,400	$ 8,400
Bank Deposit Interest							
Miscellaneous Interest Revenue	$ 7,903	$ 9,015	$ 4,112	$ 3,812	$ 3,812	$ 3,358	$ 4,800
etc.[1]							
Total	$ 18,370	$ 14,509	$ 8,952	$ 14,074	$ 14,074	$ 11,758	$ 13,200

Notes:

1 List and specify any other interest revenue.

2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that adopted IFRS on January 1, 2015, 2014 must be presented in both a CGAAP and MIFRS basis.

File Number:	EB-2015-0060
Exhibit:	3
Tab:	
Schedule:	
Page:	14
Date:	10-Aug-16

Appendix 2-I
Load Forecast CDM Adjustment Work Form (2016)

2014 is the last year of the current four year (2011-2014) CDM program, and 2015 is the first year of a new six year (2015-2020) CDM program, per the Ministerial directives of March 31, 2014. With 2016, there is a need to recognize the full year impact of the current 2011-2014 CDM program, as well as to estimate reasonable impacts for each year for the new 2015-2020 CDM program. These are combined to estimate the adjustment for CDM program impacts on the 2016 load forecast.

Appendix 2-I was developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then determined the amount of kWh (and with translation, kW of demand) savings that were converted in dollars balances for the LRAMVA, and also to determine the related adjustment to the load forecast to account for OPA-reported savings. Beginning for the 2015 year, it has been adjusted because of the persistence of 2011-2014 CDM programs will be an adjustment to the load forecast in addition to the estimated savings for the first year (2015) for the new 2015-2020 CDM plan.

It is assumed that the new six year (2015-2020) CDM program will work similar to the existing 2011-2014 CDM program, meaning that distributors will offer programs each year that, cumulatively over the six years (from January 1, 2015 to December 31, 2020) will cumulatively achieve the new six year CDM target. This is the approach contemplated in the Ministerial directive letters of March 31, 2014 to the Board and to the OPA. Thus, distributors will be able to offer programs on a basis so that cumulatively over the period, the impacts, including persistence, of the CDM programs will accumulate towards achieving each distributor's 2015-2020 CDM target.

With this approach, it is necessary to account for estimated savings for the last year of the current program, particularly the estimated savings for new CDM programs offered in 2014, as well as the estimated savings for new CDM programs that the distributor will offer in 2015 towards achievement of the new six year (2015-2020) CDM program. This necessitates expansion of this Appendix 2-I to deal with both the 2011-2014 and 2015-2020 CDM plans. It is expected that this approach will be updated each year.

2011-2014 CDM Program - 2014, last year of the current CDM plan

Input the 2011-2014 CDM target in Cell B21.

Input the measured results for 2011 CDM programs for each of the years 2011 and persistence into 2012, 2013 and 2014 into cells B31 to E31. These results are taken from the final 2011 CDM Report issued by the OPA for that distributor in the fall of 2012.

Measured results for 2012 CDM programs for each of the years 2012 and persistence into 2013 and 2014 are input into cells C32 to E32. These results are taken from the final 2012 CDM Report issued by the OPA for that distributor in the fall of 2013.

##

##

	4 Year (2011-2014) kWh Target:					Persistence of 2014 CDM Program into 2015 and 2016	
	1,210,000						
	2011	**2012**	**2013**	**2014**	**Total**	**2015**	**2016**
2011 CDM Programs	10.00%	10.00%	10.00%	9.50%	39.50%		
2012 CDM Programs		12.00%	11.95%	11.00%	34.95%		
2013 CDM Programs			8.00%	7.80%	15.80%		
2014 CDM Programs				9.75%	9.75%		
Total in Year	**10.00%**	**22.00%**	**29.95%**	**38.05%**	**100.00%**		
	kWh						
2011 CDM Programs	216,920.00	216,920.00	216,920.00	206,077.00	856,837.00		
2012 CDM Programs		260,307.00	259,222.00	238,615.00	758,144.00		
2013 CDM Programs			173,539.00	169,201.00	342,740.00		
2014 CDM Programs				211,479.00	211,479.00	242,000.00	242,000.00
Total in Year	**216,920.00**	**477,227.00**	**649,681.00**	**825,372.00**	**2,169,200.00**		

2015-2020 CDM Program - 2016, second year of the current CDM plan

For the first year of the new 2015-2020 CDM plan, it is assumed that each year's program will achieve an equal amount of new CDM savings. The new targets for 2015-2020 do not take into account persistence beyond the first year, but the IESO will encourage distributors to promote and implement CDM plans that will have longer term persistence of savings. This results in each year's program being about 1/6 (18.67%) of the cumulative 2015-2020 CDM target for kWh savings. A distributor may propose an alternative approach but would be expected to document in its application why it believes that its proposal is more reasonable. In its proposal, the distributor should ensure that the sum of the results for each year's CDM program from 2015 to 2020 add up to its 2015-2020 CDM target as established by the IESO.

6 Year (2015-2020) kWh Target: 1,057,700	2015	2016	2017	2018	2019	2020	Total
%							
2015 CDM Programs	16.67%						16.67%
2016 CDM Programs		16.67%					16.67%
2017 CDM Programs			16.67%				16.67%
2018 CDM Programs				16.67%			16.67%
2019 CDM Programs					16.67%		16.67%
2020 CDM Programs						16.67%	16.67%
Total in Year	**16.67%**	**16.67%**	**16.67%**	**16.67%**	**16.67%**	**16.67%**	**100.00%**
kWh							
2015 CDM Programs	176,283.33	176,283.33					352,566.67
2016 CDM Programs		176,283.33					176,283.33
2017 CDM Programs			176,283.33				176,283.33
2018 CDM Programs				176,283.33			176,283.33
2019 CDM Programs					176,283.33		176,283.33
2020 CDM Programs						176,283.33	176,283.33
Total in Year	**176,283.33**	**352,566.67**	**176,283.33**	**176,283.33**	**176,283.33**	**176,283.33**	**1,057,700.00**

Determination of 2016 Load Forecast Adjustment

The Board has determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the Board in other 2013 and 2-14 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-I defaults to the adjustment being done on a "net" basis consistent with Board policy and practice.

From each of the 2006-2010 CDM Final Report, and the 2011, 2012, 2013 and 2014 CDM Final Reports, issued by the OPA (now IESO) for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D84 to E88. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

Net-to-Gross Conversion

Is CDM adjustment being done on a "net" or "gross" basis? **net**

Persistence of Historical CDM programs to 2014	"Gross" kWh	"Net" kWh	Difference kWh	Conversion Factor ('g')
2006-2010 CDM programs	**2,166,685.00**	**1,200,569.00**		
2011 CDM program	**601,071.00**	**534,741.00**		
2012 CDM program	**1,049,177.00**	**987,991.00**		
2013 CDM program	**355,549.00**	**341,418.00**		
2014 CDM program	**365,234.00**	**305,050.00**		
2006 to 2014 OPA CDM programs: Persistence to 2016	4,537,716.00	3,369,769.00	1,167,947.00	34.66%

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.

These factors do not mean that CDM programs are excluded, but the assumption that impacts of previous year CDM programs are already implicitly reflected in the actual data for the historical years that are the basis for the load forecast prior to any manual CDM adjustment for the 2016 test year.

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast

	2011	2012	2013	2014	2015	2015	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0**	**0**	**0**	**0**	**0**	**0**	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Full year persistence of 2011 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2011 (first year) but full year persistence impact on 2012 and 2013, and thus reflected in base forecast before the CDM adjustment.*	*Full year persistence of 2012 CDM programs on 2015 load forecast. Full impact assumed because of 50% impact in 2012 (first year) but full year persistence impact on 2013, and thus reflected in base forecast before the CDM adjustment.*	*Default is 0, but one option is for full year impact of persistence of 2013 CDM programs on 2015 load forecast, but 50% impact in base forecast (first year impact of 2013 CDM programs on 2013 load forecast, which is part of the data for the load forecast.*	*Default is 0, but one option is for full year impact of persistence of 2014 CDM programs on 2014 load forecast, but 50% impact in base forecast (first year impact of 2014 CDM programs on 2014 actuals, which is part of the data for the load forecast.*	*Full year impact of persistence of 2015 programs on 2015 load forecast. 2015 CDM program impacts are not in the base forecast.*	*Only 50% of 2016 CDM programs are assumed to impact the 2016 load forecast based on the "half-year" rule.*	

2011-2014 and 2015-2020 LRAMVA and 2015 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2015 load forecast is made. However, the distributor will have two associated annualized CDM impacts, one for the 2011-2014 CDM program and the second for the 2015-2020 CDM plan. In addition, the distributor needs to reflect the CDM adjustment that was explicitly factored into its 2011 load forecast in its 2011 cost of service application (assuming that it rebased in that year). this amount, and equal persistence for 2012, 2013 and 2014 is used as an offset to determine what the net balance of the 2011-2014 LRAMVA balance should be for disposition.

The Amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

The proposed loss factor should correspond with the loss factor calculated in Appendix 2-R

The Manual Adjustment for the 2016 Load Forecast is the amount manually subtracted from the load forecast derived from the base forecast from historical data.

If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

The distributor should determine the allocation of the savings to all customer classes in a reasonable manner (e.g. taking into account what programs and what OPA-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2011 kWh	2012	2013	2014	2015	2016	Total for 2016
Amount used for CDM threshold for LRAMVA (2014)	206,077.00	238,615.00	169,201.00	211,479.00			
forecast (per Board Decision in distributor's most recent Cost of Service Application) (enter as negative)	- 242,000.00	- 242,000.00	- 242,000.00	- 242,000.00			
Amount used for CDM threshold for LRAMVA (2016)				242,000.00	176,283.33	176,283.33	594,566.67
Manual Adjustment for 2016 Load Forecast (billed basis)	-	-	-	-	-	-	-
Proposed Loss Factor (TLF)	8.98%	Format: X.XX%					
Manual Adjustment for 2016 Load Forecast (system purchased basis)	-	-	-	-	-	-	-

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2016 load forecast.

File Number:	EB-2015-0060
Exhibit:	3
Tab:	
Schedule:	
Page:	
Date:	10-Aug-16

Appendix 2-IA
Summary and Variances of Actual and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

	2012 Board Approved	2012	2013	2014	2015 Bridge	2016 Test
Residential						
# of Customers	1,133	1,099	1,076	1,068	1,065	1,063
kWh	14,448,113	13,606,692	14,615,491	15,225,943	14,458,774	14,291,097
kW	-	-	-	-	-	-
Variance Analysis						
# of Customers		-3.00%	-5.03%	-5.74%	-6.00%	-6.18%
kWh		-5.82%	1.16%	5.38%	0.07%	-1.09%
kW		0.00%	0.00%	0.00%	0.00%	0.00%
General Service <50 kW						
# of Customers	161	162	157	154	153	152
kWh	5,209,322	4,978,478	5,220,157	5,251,375	4,942,820	4,842,432
kW	-					
Variance Analysis						
# of Customers		0.62%	-2.48%	-4.35%	-4.97%	-5.59%
kWh		-4.43%	0.21%	0.81%	-5.12%	-7.04%
kW		0.00%	0.00%	0.00%	0.00%	0.00%
General Service >50 kW						
# of Customers	14	14	14	13	13	13
kWh	7,592,321	7,124,651	7,033,427	7,157,299	6,769,262	6,630,340
kW	19,360	18,736	18,430	18,429	17,660	17,297
Variance Analysis						
# of Customers		0.00%	0.00%	-7.14%	-7.14%	-7.14%
kWh		-6.16%	-7.36%	-5.73%	-10.84%	-12.67%
kW		-3.22%	-4.80%	-4.81%	-8.78%	-10.66%
Unmetered Scattered Load						
# of Customers	6	5	5	4	4	4
kWh	7,209	5,511	5,052	4,068	3,860	3,584
kW	-					
Variance Analysis						
# of Customers		-16.67%	-16.67%	-33.33%	-33.33%	-33.33%
kWh		-23.55%	-29.92%	-43.57%	-46.46%	-50.28%
kW		0.00%	0.00%	0.00%	0.00%	0.00%
Sentinel Lighting						
# of Customers	23	23	23	23	23	23
kWh	25,718	26,265	27,271	26,857	27,099	26,757
kW	65	60	65	65	66	66
Variance Analysis						
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%
kWh		2.13%	6.04%	4.43%	5.37%	4.04%
kW		-7.69%	0.00%	0.00%	1.54%	1.54%
Street Lighting						
# of Customers	341	328	328	328	328	328
kWh	292,061	290,000	278,311	274,528	273,712	267,045
kW	773	777	767	768	742	724
Variance Analysis						
# of Customers		-3.81%	-3.81%	-3.81%	-3.81%	-3.81%
kWh		-0.71%	-4.71%	-6.00%	-6.28%	-8.57%
kW		0.52%	-0.78%	-0.65%	-4.01%	-6.34%

File Number:	EB-2015-0060
Exhibit:	3
Tab:	
Schedule:	
Page:	
Date:	10-Aug-16

Appendix 2-IA
Summary and Variances of Actual and Forecast Data

Rate Class 7						
# of Customers						
kWh						
kW						
Variance Analysis						
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%

Rate Class 8						
# of Customers						
kWh						
kW						
Variance Analysis						
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%

Rate Class 9						
# of Customers						
kWh						
kW						
Variance Analysis						
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%

Rate Class 10						
# of Customers						
kWh						
kW						
Variance Analysis						
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%

Totals

Customers / Connections	1,678	1,631	1,603	1,590	1,586	1,583
kWh	27,574,744	26,031,597	27,179,709	27,940,070	26,475,527	26,061,255
kW from applicable classes	20,198	19,573	19,262	19,262	18,468	18,087

Totals - Variance

Customers / Connections		-2.80%	-4.47%	-5.24%	-5.48%	-5.66%
kWh		-5.60%	-1.43%	1.32%	-3.99%	-5.49%
kW from applicable classes		-3.09%	-4.63%	-4.63%	-8.57%	-10.45%

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	5
Date:	10-Aug-16

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis						
Operations	$ 205,440	$ 199,644	$ 220,412	$ 223,211	$ 230,363	$ 242,020
Maintenance	$ -	$ -	$ -	$ -	$ -	$ -
SubTotal	**$ 205,440**	**$ 199,644**	**$ 220,412**	**$ 223,211**	**$ 230,363**	**$ 242,020**
%Change (year over year)			10.4%	1.3%	3.2%	5.1%
%Change (Test Year vs Last Rebasing Year - Actual)						21.2%
Billing and Collecting	$ 84,200	$ 185,653	$ 115,086	$ 135,609	$ 95,481	$ 97,200
Community Relations	$ 600	$ 115	$ 415	$ 415	$ 200	$ 600
Administrative and General	$ 354,100	$ 295,079	$ 309,681	$ 392,489	$ 370,557	$ 388,480
SubTotal	**$ 438,900**	**$ 480,847**	**$ 425,182**	**$ 528,513**	**$ 466,238**	**$ 486,280**
%Change (year over year)			-11.6%	24.3%	-11.8%	4.3%
%Change (Test Year vs Last Rebasing Year - Actual)						1.1%
Total	**$ 644,340**	**$ 680,491**	**$ 645,594**	**$ 751,724**	**$ 696,601**	**$ 728,300**
%Change (year over year)			-5.1%	16.4%	-7.3%	4.6%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Operations	$ 205,440	$ 199,644	$ 220,412	$ 223,211	$ 230,363	$ 242,020
Maintenance	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collecting	$ 84,200	$ 185,653	$ 115,086	$ 135,609	$ 95,481	$ 97,200
Community Relations	$ 600	$ 115	$ 415	$ 415	$ 200	$ 600
Administrative and General	$ 354,100	$ 295,079	$ 309,681	$ 392,489	$ 370,557	$ 388,480
Total	**$ 644,340**	**$ 680,491**	**$ 645,594**	**$ 751,724**	**$ 696,601**	**$ 728,300**
%Change (year over year)			-5.1%	16.4%	-7.3%	4.6%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	Variance 2012 BA – 2012 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	2014 Actuals	Variance 2014 Actuals vs. 2013 Actuals	2015 Bridge Year	Variance 2015 Bridge vs. 2014 Actuals	2016 Test Year	Variance 2016 Test vs. 2015 Bridge
Operations	$ 205,440	$ 199,644	$ 5,796	$ 220,412	$ 20,768	$ 223,211	$ 2,799	$ 230,363	$ 7,152	$ 242,020	$ 11,657
Maintenance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Billing and Collecting	$ 84,200	$ 185,653	-$ 101,453	$ 115,086	-$ 70,567	$ 135,609	$ 20,523	$ 95,481	-$ 40,128	$ 97,200	$ 1,719
Community Relations	$ 600	$ 115	$ 485	$ 415	$ 300	$ 415	$ -	$ 200	-$ 215	$ 600	$ 400
Administrative and General	$ 354,100	$ 295,079	$ 59,021	$ 309,681	$ 14,602	$ 392,489	$ 82,808	$ 370,557	-$ 21,932	$ 388,480	$ 17,923
Total OM&A Expenses	$ 644,340	$ 680,491	-$ 36,151	$ 645,594	-$ 34,897	$ 751,724	$ 106,130	$ 696,601	-$ 55,123	$ 728,300	$ 31,699
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ 644,340	$ 680,491	-$ 36,151	$ 645,594	-$ 34,897	$ 751,724	$ 106,130	$ 696,601	-$ 55,123	$ 728,300	$ 31,699
Variance from previous year				-$ 34,897		$ 106,130		-$ 55,123		$ 31,699	
Percent change (year over year)				-5%		16%		-7%		5%	
Percent Change: Test year vs. Most Current Actual						-3.12%					
Simple average of % variance for all years						7.03%					2%
Compound Annual Growth Rate for all years											1.4%
Compound Growth Rate (2014 Actuals vs. 2012 Actuals)						3.37%					

Note:

1 "BA" = Board-Approved
2 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
3 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	7
Date:	10-Aug-16

Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis					
Opening Balance	$ 644,340	$ 680,491	$ 645,594	$ 751,724	$ 696,601
5020 - Overhead Distr, Lines - Labour	$ 11,143		$ 11,776		
5025 - Overhead Distr, Lines & Feeders - Supplies	-$ 16,834	$ 19,841	-$ 14,711		
5610 - Management Salaries and Expenses					$ 18,348
5630 - Outside Services Employed	-$ 47,802	-$ 18,883		$ 60,800	-$ 25,925
5655 - Regulatory Expense - Intervenors		$ 12,199			
5665 - Misc. General Expenses			$ 94,798	-$ 98,989	
5065 - Meter Expense (Sensus & Harris)	$ 90,067	-$ 90,067			
5310 - Meter Reading Expense		$ 12,579			
5315 - Customer Billing	$ 17,845			-$ 12,228	
5335 - Bad Debt Expense			$ 23,102	-$ 28,571	
Other	-$ 18,268	$ 29,434	-$ 8,835	$ 23,865	$ 39,276
Closing Balance	$ 680,491	$ 645,594	$ 751,724	$ 696,601	$ 728,300

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is

2 For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than

4 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	17
Date:	10-Aug-16

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year	Variance (Test Year vs. 2014 Actuals)	Variance (Test Year vs. Last Rebasing Year (2012 Board-Approved)
Reporting Basis								
Operations and Maintenance								
Distribution Station	5,700	4,024	2,494	3,390	3,786	4,200	810	-1,500
Overhead Distr. Lines and Feeders	197,400	191,710	215,912	215,231	223,385	233,400	18,169	36,000
Meters	600	2,009	1,120	1,675	1,665	2,500	825	1,900
OH Distr. Lines and Feeders-Rental	1,740	1,900	887	2,914	1,527	1,920	-994	180
							0	0
Sub-Total	205,440	199,644	220,412	223,211	230,362	242,020	18,809	36,580
Customer Service								
Meter Reading	29,000	112,100	34,612	30,967	31,637	32,400	1,433	3,400
Billing and Collections	51,600	69,445	73,805	74,871	62,644	61,200	-13,671	9,600
Bad Debt	3,600	4,107	6,669	29,771	1,200	3,600	-26,171	0
							0	0
							0	0
Sub-Total	84,200	185,653	115,086	135,609	95,481	97,200	-38,409	13,000
Administration								
Admin., Employee Benefits and Exp.	157,980	156,575	171,683	164,007	173,192	203,800	39,793	45,820
Outside Services Employed	106,400	58,598	39,715	49,125	109,925	84,000	34,875	-22,400
Regulatory Expenses	14,520	6,785	18,809	7,226	9,082	14,100	6,874	-420
Property Insurance	17,040	13,544	14,491	13,770	14,767	14,800	1,030	-2,240
Office Supplies and Expenses	24,000	19,194	22,017	20,587	25,935	25,480	4,893	1,480
Bank Charges	0	8,714	9,043	9,118	7,798	8,700	-418	8,700
							0	0
Sub-Total	319,940	263,411	275,758	263,833	340,698	350,880	87,047	30,940
Other								
Community Relations	600	115	415	415	200	600	185	0
Taxes Other than Income Taxes	0	9,885	7,123	7,050	7,252	8,000	950	8,000
Leap Funding	2,000	2,000	2,000	2,000	2,000	2,000	0	0
Misc. General Expenses	32,160	19,785	24,800	119,605	20,609	27,600	-92,005	-4,560
							0	0
Sub-Total	34,760	31,784	34,338	129,071	30,061	38,200	-90,871	3,440
Program Name #5								
							0	0
							0	0
							0	0
							0	0
							0	0
Sub-Total	0	0	0	0	0	0	0	0
Miscellaneous							0	0
Total	**644,340**	**680,492**	**645,594**	**751,724**	**696,602**	**728,300**	**-23,424**	**83,960**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

File Numbe	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	25
Date:	10-Aug-16

Appendix 2-K
Employee Costs

	Last Rebasing Year - 2012-Board Approved	Last Rebasing Year - 2012-Actual	Last Rebasing Year - 2012-Board Approved	Last Rebasing Year - 2012-Actual	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
	Partial	**Partial**	**All In**	**All In**	**All In**	**All In**	**All In**	**All In**
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	1	1	1	1	1	1	1	1.0
Non-Management (union and non-union)	4	4	4	4	4	4	4	5
Total	5	5	5	5	5	5	5	5.33
Total Salary and Wages including ovetime and incentive pay								
Management (including executive)								
Non-Management (union and non-union)	$ 251,684	$ 260,248	$ 300,631	$ 309,195	$ 311,733	$ 331,557	$ 330,461	$ 369,000
Total	$ 251,684	$ 260,248	$ 300,631	$ 309,195	$ 311,733	$ 331,557	$ 330,461	$ 369,000
Total Benefits (Current + Accrued)								
Management (including executive)								
Non-Management (union and non-union)	$ 61,452	$ 63,665	$ 75,040	$ 77,253	$ 84,609	$ 80,285	$ 80,546	$ 91,200
Total	$ 61,452	$ 63,665	$ 75,040	$ 77,253	$ 84,609	$ 80,285	$ 80,546	$ 91,200
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Management (union and non-union)	$ 313,136	$ 323,913	$ 375,671	$ 386,448	$ 396,342	$ 411,842	$ 411,007	$ 460,200
Total	$ 313,136	$ 323,913	$ 375,671	$ 386,448	$ 396,342	$ 411,842	$ 411,007	$ 460,200

Note:

[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	14
Date:	10-Aug-16

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year - 2012- Board Approved	Last Rebasing Year - 2012- Actual	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Number of Customers [2,4]	1,661	1,644	1,617	1,597	1,588	1,586
Total Recoverable OM&A from Appendix 2-JB	$ 644,340	$ 680,491	$ 645,594	$ 751,724	$ 696,601	$ 728,300
OM&A cost per customer	$ 387.92	$ 413.92	$ 399.25	$ 470.86	$ 438.67	$ 459.21
Number of FTEs [3,4]	5	5	5	5	5	5.33
Customers/FTEs	332.20	328.80	323.40	319.30	317.60	297.56
OM&A Cost per FTE	128,868.00	136,098.20	129,118.80	150,344.80	139,320.20	136,641.65

Notes:

1. If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
2. The method of calculating the number of customers must be identified.
3. The method of calculating the number of FTEs must be identified. See also Appendix 2-K
4. The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

File Number:	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	80
Date:	10-Aug-16

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2012 Board Approved)	Most Current Actuals Year 2014	2015 Bridge Year	Annual % Change	2016 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655	$ -	On-Going	$ 5,100	$ 3,995	$ 4,802	20.20%	$ 5,000	4.12%
2	OEB Section 30 Costs (Applicant-originated)									
3	OEB Section 30 Costs (OEB-initiated)									
4	Expert Witness costs for regulatory matters									
5	Legal costs for regulatory matters									
6	Consultants' costs for regulatory matters	5630	$ -	On-Going	$ 17,000	$ 12,744	$ 21,050	65.18%	$ 18,000	-14.49%
7	Operating expenses associated with staff resources allocated to regulatory matters									
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments	5655	$ -	On-Going	$ 1,700	$ 1,688	$ 1,763	4.44%	$ 1,900	7.77%
10	Any other costs for regulatory matters (please define)- OEB Licence fees, Cost Awards	5655	$ -	On-Going	$ 1,000	$ 910	$ 1,209	32.86%	$ 1,100	-9.02%
11	Intervenor costs	Sub. a/c 5655	$ -	On-Going	$ 6,720	$ 633	$ -	-100.00%	$ 6,100	
12	Sub-total - Ongoing Costs [3]		$ -		$ 31,520	$ 19,970	$ 28,824	44.34%	$ 32,100	11.37%
13	Sub-total - One-time Costs [4]		$ -		$ -	$ -	$ -		$ -	
14	Total		$ -		$ 31,520	$ 19,970	$ 28,824	44.34%	$ 32,100	11.37%

Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2015 Bridge Year	2016 Test Year
4	Expert Witness costs	0	0	0
5	Legal costs	0	0	0
6	Consultants' costs	0	0	0
7	Incremental operating expenses associated with staff resources allocated to this application.	0	0	0
8	Incremental operating expenses associated with other resources allocated to this application. [1]	0	0	0
11	Intervenor costs	0	0	0

Notes:

1 Please identify the resources involved.

2 Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.

3 Sum of all ongoing costs identified in rows 1 to 11 inclusive.

4 Sum of all one-time costs identified in rows 1 to 11 inclusive.

File Numbe	EB-2015-0060
Exhibit:	4
Tab:	
Schedule:	
Page:	31
Date:	10-Aug-16

Appendix 2-N

Shared Services and Corporate Cost Allocation [1]

Year: Test Year 2016

Shared Services

Name of Company		Service Offered	Pricing Methodology	Service	Service	2012 Test Year Board Approved Service
From	To					
				$	$	$
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Distribution Station Equipment - Maintenance	Cost Based. 100% of actual time spent. (As Per Operation and Service Agreement)	$3,000	$3,000	$4,500
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Distribution Station Equipment - Operation Supplies	Cost Based. 100% of actual Supplies Used. (As Per Operation and Service Agreement)	$1,200	$1,200	$1,200
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Overhead Distribution Lines & Feeders - Maintenance	Cost Based. 100% of actual time spent. (As Per Operation and Service Agreement)	$150,000	$150,000	$121,200
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Overhead Distribution Lines & Feeders - Operation Supplies	Cost Based. 86.8 % of actual Supplies Used. (As Per Operation and Service Agreement)	$7,000	$7,000	$7,000
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Meter Reading, Installation and Maintenance	Cost Based. 100% of actual time spent. (As Per Operation and Service Agreement)	$2,500	$2,500	$1,680
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Meter Reading, Installation and Maintenance Supplies	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$0	$0	$600
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	On Call Expense	Cost Based. 100% of actual time spent. (As Per Operation and Service Agreement)	$7,800	$7,800	$7,800
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Holidays and Sick Time	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$26,400	$26,400	$17,400
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Truck Expense	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$30,000	$30,000	$30,000
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Customer Billing	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$44,200	$44,200	$40,000
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Management Salaries and Expense	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$84,000	$84,000	$54,000
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Outside Services Employed	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$3,500	$3,500	$12,000
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Office Supplies and Expense	Based on Costs incurred to date is allocated based on the appropriate %ge. (As Per Operation and Service Agreement)	$25,480	$25,480	$19,500
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Property Insuranse	Based on Costs incurred to date is allocated based on the appropriate %ge. (As Per Operation and Service Agreement)	$950	$950	$925
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Employee Pension and Benefits	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$32,400	$32,400	$17,640
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	EHT Expense	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$5,000	$5,000	$3,900
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	WSIB Expense	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$3,200	$3,200	$2,640
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	CPP Expense	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$12,000	$12,000	$8,770
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	EI Expense	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$6,000	$6,000	$4,335
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Group Insurance	Cost Based. 86.8% of actual time spent. (As Per Operation and Service Agreement)	$48,000	$48,000	$40,800
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Taxes Other Than Income Taxes	Based on Costs incurred to date is allocated based on the appropriate %ge. (As Per Operation and Service Agreement)	$8,000	$8,000	$7,950
Chapleau Energy Services Corporation	Chapleau Public Utilities Corporation	Miscellaneous General Expenses	Based on Costs incurred to date is allocated based on the appropriate %ge. (As Per Operation and Service Agreement)	$1,500	$1,500	$14,096
			TOTAL	**$502,130**	**$502,130**	**$417,936**

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	Corporate	Allocated
From	To				
				%	$
eg: parent company	*eg: regulated entity*				
	NOT APPLICABLE - There are no Corporate cost Allocations				

Note: 1

This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years.

· ***Type of Service:***
Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent c

· ***Pricing Methodology:***
Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demo methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in it is appropriate.

· ***% Allocation:***
The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also pr allocator and why it is an appropriate allocator.

File Number:	EB-2015-0060
Exhibit:	5
Tab:	
Schedule:	
Page:	2
Date:	10-Aug-16

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board approved year and the test year.

Year: 2012 Board Approved

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$846,878	4.41%	$37,347
2	Short-term Debt	4.00%	(1)	$60,491	2.08%	$1,258
3	**Total Debt**	60.0%		$907,370	4.25%	$38,606
	Equity					
4	Common Equity	40.00%		$604,913	9.12%	$55,168
5	Preferred Shares	0.00%		$ -	9.12%	$ -
6	**Total Equity**	40.0%		$604,913	9.12%	$55,168
7	**Total**	100.0%		$1,512,283	6.20%	$93,774

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

File Number:	EB-2015-0060
Exhibit:	5
Tab:	
Schedule:	
Page:	4
Date:	10-Aug-16

Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	2016 - Long Term Loan for New Sub-Station	Infrastructure Ontario	Third-Party	Fixed Rate	August 1,2016	30	$ 1,035,619	3.50%	$ 15,102.78	Financing Not Yet in Place
2	2015 - No Long Term Loan								$ -	
3	2014 - No Long Term Loan								$ -	
4	2013 - No Long Term Loan								$ -	
5	2012 - No Long Term Loan								$ -	
6	2011 - No Long Term Loan								$ -	
7	2010 - No Long Term Loan								$ -	
8	" "								$ -	
9	" "								$ -	
10	" "								$ -	
11	" "								$ -	
12	" "								$ -	
Total							$ 1,035,619	0.0145833	$ 15,102.78	

Notes

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009, or with any subsequent update issued by the Board.

3 Add more lines above row 12 if necessary.

File Number:	EB-2015-0060
Exhibit:	7
Tab:	
Schedule:	
Page:	4
Date:	10-Aug-16

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 555,163	66.04%	$ 625,890	70.24%
GS < 50 kW	$ 157,634	18.75%	$ 153,411	17.22%
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$ 78,675	9.36%	$ 95,342	10.70%
GS > xxx kW, if applicable		0.00%		0.00%
Large User, if applicable		0.00%		0.00%
Street Lighting	$ 43,055	5.12%	$ 9,610	1.08%
Sentinel Lighting	$ 4,363	0.52%	$ 5,498	0.62%
Unmetered Scattered Load (USL)	$ 1,763	0.21%	$ 1,369	0.15%
Other class, if applicable		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class		0.00%		0.00%
Total	$ 840,653	100.00%	$ 891,120	100.00%

Notes:

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue
Residential	$ 506,730	$ 551,538	$ 593,934	$ 31,957
GS < 50 kW	$ 150,848	$ 164,187	$ 146,482	$ 6,929
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$ 84,110	$ 91,547	$ 91,482	$ 3,861
GS > xxx kW, if applicable				
Large User, if applicable				
Street Lighting	$ 32,367	$ 35,229	$ 9,227	$ 383
Sentinel Lighting	$ 3,380	$ 3,679	$ 5,208	$ 290
Unmetered Scattered Load (USL)	$ 1,320	$ 1,437	$ 1,284	$ 85
Other class, if applicable				
Embedded distributor class				
Total	$ 778,755	$ 847,617	$ 847,617	$ 43,505

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate riders.

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2015	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	97.47	93.23	100.00	85 - 115
GS < 50 kW	104.28	111.54	100.00	80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	120.00	100.07	100.00	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	81.52	370.57	100.00	80 - 120
Sentinel Lighting	81.53	72.19	100.00	80 - 120
Unmetered Scattered Load (USL)	118.80	111.18	100.00	80 - 120
Other class, if applicable				
Embedded distributor class				

Notes:

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2016	2017	2018	
	%	%	%	%
Residential	100.00	0	0	85 - 115
GS < 50 kW	100.00	0	0	80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	100.00	0	0	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	100.00			80 - 120
Sentinel Lighting	100.00			80 - 120
Unmetered Scattered Load (USL)	100.00			80 - 120
Other class, if applicable				0
				0
Embedded distributor class				

Note:

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2014 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2016. In 2017 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2016 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

File Number:	EB-2015-0060
Exhibit:	8
Tab:	
Schedule:	
Page:	5
Date:	10-Aug-16

Appendix 2-PA
New Rate Design Policy For Residential Customers

Please complete the following tables.

A) Data Inputs

Test Year Billing Determinants for Residential Class	
Customers	1,063
kWh	14,291,097

Proposed Residential Class Specific Revenue Requirement[1]	$ 593,933.00

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	24.04
Distribution Volumetric Rate ($/kWh)	0.014

B) Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	24.04	1,063	$ 306,654.24	60.52%
Variable	0.0140	14,291,097	$ 200,075.36	39.48%
TOTAL	-	-	$ 506,729.60	-

C) Calculating Test Year Base Rates

Number of Required Rate Design Policy Transition Years[2]	5

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 359,426.55	28.18	$ 359,464.08
Variable	$ 234,506.45	0.0164	$ 234,373.99
TOTAL	$ 593,933.00	-	$ 593,838.07

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Reconciliation @ Adjusted Rates
Fixed	68.4131%	$ 406,327.84	31.85	$ 406,278.60
Variable	31.5869%	$ 187,605.16	0.0131	$ 187,213.37
TOTAL	-	$ 593,933.00	-	$ 593,491.97

Checks[3]	
Change in Fixed Rate	$ 3.67
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	-$ 441.03
	-0.07%

Notes:

1 The final residential class specific revenue requirement, as shown in Appendix 2-P, should be used (i.e. the revenue requirement after any proposed adjustments to R/C ratios).

2 Default number of transition years for rate design policy change is 4. Where the change in the residential rate design will result in the fixed charge increasing by more than $4/year, a distributor may propose an additional transition year.

3 Change in fixed rate due to rate design policy should be less than $4. The difference between the proposed class revenue requirement and the revenue at calculated base rates should be minimal (i.e. should be reasonably considered as a rounding error)

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-Q
Cost of Serving Embedded Distributor(s)

To be completed by Host Distributors ONLY
(Not required if Host Distributor has an Embedded Distributor rate class, i.e. a separate row in Appendix 2-P.)

Proposed Rate Class for Billing Embedded Distributor(s)

Host's Distribution Facilities used by Embedded Distributor(s)

(1)	(2)	(3)	(4)	(5)	(6) = '(3) + (4)
Asset Class	**Total OM&A costs asociated with asset class**	**Original cost of asset class**	**Accumulated amortization of asset class**	**Annual amortization of asset class**	**Net Book Value of asset class**
Totals for Host Distributor:	($)	($)	($)	($)	
Distribution Stations					$ -
Low Voltage Line					$ -
LV Line category # 2 (if applcable)					$ -
TS (owned by host)					$ -
add rows if necessary...					$ -
					$ -
					$ -

(1)	(7)	(8)	(9)	(10)	(11)
Asset Class	**Total line length or station capacity in asset class**	**Line length or capacity required to provide LV service to Embedded Distributor(s)**	**Annual total demand on station/line providing LV services (sum of 12 monthly peaks)**	**Annual billed Embedded Distributor demand on station/line providing LV services**	**Embedded Distributor(s)' Responsibility Share**
Embedded Distributor's share:	kW or kVa; km	kW or kVA; km	kW or kVA	kW or kVA	percent
Distribution Stations					0.00%
Low Voltage Line					0.00%
LV Line # 2 (if applicable)					0.00%
TS (owned by host)					0.00%
add rows if necessary					0.00%

(1)	(12)	(12a)	(13)	(14)	(15)	(16)
Asset Class	**Return on Assets used to Provide LV services**	**Taxes/PILs**	**Annual amortization on assets used to provide LV services**	**OM&A costs with burden associated with assets used to provide LV services**	**Total annual cost associated with assets used to provide LV services**	**Monthly cost associated with the delivery of LV services**
	($)	($)	($)	($)	($)	$/kW or $/kVA
Distribution Stations	$ -	$ -	$ -	$ -	$ -	0.00
Low Voltage Line	$ -	$ -	$ -	$ -	$ -	0.00
LV Line # 2 (if applicable)	$ -	$ -	$ -	$ -	$ -	0.00
TS (owned by host)	$ -	$ -	$ -	$ -	$ -	0.00
add rows if necessary	$ -	$ -	$ -	$ -	$ -	0.00
Total					**$ -**	**0.00**

(17)	(18) Capital Structure (%)	(19) Cost Rate (%)	(20)	(21) (%)
Long-Term Debt			Weighted Average Cost of Capital	0.00%
Short-term Debt				
Common Equity			Tax/PILs Rate	
Preferred Shares				
Total	0.00%		Working Capital Allowance Factor	

File Number	EB-2015-0060
Exhibit:	8
Tab:	
Schedule:	
Page:	12
Date:	10-Aug-16

Appendix 2-R
Loss Factors

		Historical Years					5-Year
		2010	**2011**	**2012**	**2013**	**2014**	**Average**
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	-					-
A(2)	"Wholesale" kWh delivered to distributor (lower value)	#########	#########	#########	#########	#########	28,817,116
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-					-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	#########	#########	#########	#########	#########	28,817,116
D	"Retail" kWh delivered by	#########	#########	#########	#########	#########	26,841,581
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-					-
F	Net "Retail" kWh delivered by distributor = **D - E**	#########	#########	#########	#########	#########	26,841,581
G	Loss Factor in Distributor's system = **C / F**	1.0666	1.0588	1.0760	1.0948	1.0716	1.0736
	Losses Upstream of						
H	Supply Facilities Loss Factor	1.0151	1.0151	1.0151	1.0152	1.0150	1.0151
	Total Losses						
I	Total Loss Factor = **G x H**	1.0826	1.0748	1.0923	1.1114	1.0876	1.0898

Notes:

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-

If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).

D kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

G and These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H If directly connected to the IESO-controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor's system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be

Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal ir calculations and any other relevant material.

File Number:	EB-2015-0060
Exhibit:	2
Tab:	
Schedule:	
Page:	35
Date:	10-Aug-16

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$ -		$ -
2007					$ -		$ -
2008		Stranded Meters were delt with in the last			#VALUE!		#VALUE!
2009					$ -		$ -
2010		COS aplication in 2012			#VALUE!		#VALUE!
2011					$ -		$ -
2012					$ -		$ -
2013					$ -		$ -
2014					$ -		$ -
2015	(1)				$ -		$ -

Notes:

(1) *For 2015, please indicate whether the amounts provided are on a forecast or actual basis.*

Some distributors have transferred the cost of stranded meters from Account 1860 - Meters to "Sub-account Stranded Meter Costs of Account 1555", while in some cases distributors have left these costs in Account 1860. Depending on which treatment the applicant has chosen. please provide the information under either of the two scenarios (A and B below), as applicable.

Scenario A: *If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555, the above table should be completed and the following information should be provided in Exhibit 9.*

1 A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2 The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, which were transferred to this sub-account as of December 31, 2010.

3 A statement as to whether or not, since transferring the removed stranded meter costs to the sub-account, the recording of depreciation expenses was continued in order to reduce the net book value through accumulated depreciation. If so, the total depreciation expense amount for the period from the time the costs for the stranded meters were transferred to the sub-account to December 31, 2010 should be provided.

If no depreciation expenses were recorded to reduce the net book value of stranded meter costs through accumulated depreciation, the total depreciation expense amount that would have been applicable from the time that the stranded meter costs were transferred to the sub-account of Account 1555 to December 31, 2010 should be provided. In addition, the following information should be provided:

a) Whether or not carrying charges were recorded for the stranded meter cost balances in the sub-account, and if so, the total carrying charges recorded to December 31, 2010.

b) The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when the smart meters will have been fully deployed (e.g., as of December 31, 2010). If the smart meters have been fully deployed, the actual amount should be provided.

c) A description as to how the applicant intends to recover in rates the remaining costs for stranded meters, including the proposed accounting treatment, the proposed disposition period, and the associated bill impacts.

Scenario B: *If the stranded meter costs remained recorded in Account 1860, the above table should be completed and the following information should be provided in Exhibit 9:*

1. A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

2. The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2010.

3. A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2010.

4. If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2010.

5. The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.

6. A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

Distributors should also provide the Net Book Value per class of meter as of December 31, 2010 as well as the number of meters that were removed / stranded. In preparing this information, distributors should review the Board's letter of January 16, 2007 *Stranded Meter Costs Related to the Installation of Smart Meters* which stated that records were to be kept of the type and number of each meter to support the stranded meter costs.

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-TA
Account 1592, PILs and Tax Variances for 2006 and Subsequent Years

The following table should be completed based on the information requested below, in accordance with the notes following the table. An explanation should be provided for any blank entries.

Tax Item	Principal as of December 31, 20XX
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007	
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4/12ths of the approved grossed-up proxy), if not recorded in PILs account 1562	
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	Acccount 1592
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	was dealt with in
Ontario Capital Tax rate decrease and increase in capital deduction for 2011	the 2012 COS
Ontario Capital Tax rate decrease and increase in capital deduction for 2012	EB-2011-0322
Ontario Capital Tax rate decrease and increase in capital deduction for 2013	
Capital Cost Allowance class changes from 2006 EDR application for 2006	
Capital Cost Allowance class changes from 2006 EDR application for 2007	
Capital Cost Allowance class changes from 2006 EDR application for 2008	
Capital Cost Allowance class changes from 2006 EDR application for 2009	
Capital Cost Allowance class changes from 2006 EDR application for 2010	
Capital Cost Allowance class changes from 2006 EDR application for 2011	
Capital Cost Allowance class changes from 2006 EDR application for 2012	
Capital Cost Allowance class changes from 2006 EDR application for 2013	
Capital Cost Allowance class changes from any prior application not recorded above. Please provide details and explanation separately.	
Insert description of additional item(s) and new rows if needed.	
Total	$ -

Notes:

1 Revise the deferral and variance account continuity schedule to include account 1592 as a group 2 account and enter all relevant information for transactions, adjustments, etc., for all relevant years.

2 Describe each type of tax item that has been recorded in account 1592.

3 Provide the calculations that show how each item was determined and provide any pertinent supporting evidence and documentation.

4 Please state whether or not the applicant followed the guidance provided in the FAQ of July 2007. If not, please provide an explanation.

5 Identify the account balance as of December 31, 2012 as per the 2012 Audited Financial Statements. Identify the account balance as of December 31, 2012 as per the April 2013 2.1.7 RRR filing to the Board. Provide a reconciliation if the balances provided are not identical to each other and to the total shown on the continuity schedule.

6 Complete the above table based on the answers to the previous. Add rows as required to complete the analysis in an informative manner. Please provide the completed table as a working Excel spreadsheet.

File Number:	EB-2015-0060
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-TB
Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs)

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries.

100% of the balance in Account 1592, PILs and Tax Variances for 2006 and Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs), should be recorded in this table.

Summary of PST Savings from 2009 Historic Year Analysis

	Principal 2010	Principal 2011	Principal 2012	Principal 2013	Principal 2014	Principal 2015	Principal Jan-April 2016 [1]	Carrying Charges to April 30, 2016	Total Account 1592, sub-account HST/OVAT Balance
OM&A Expenses PST Savings									
Capital Items PST Savings									
Total Annual PST Savings [2]									

Notes:

[1] Include January to April 30, 2016 PST savings if the rate year begins May 1, 2016. If the rate year begins Jan 1, 2016, include PST savings to December 31, 2015.
[2] Derived PST savings proxy for each year per 2009 historical year analysis

Note: Assumes level OM&A and Capital Spending year over year. An alternative detailed transactional analysis may also be performed using actual expenditures from 2010 to the start of the rate

File Number:	EB-2015-0060
Exhibit:	9
Tab:	
Schedule:	
Page:	6
Date:	10-Aug-16

Appendix 2-U
One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	**Audited Actual Costs Incurred 2009**	**Audited Actual Costs Incurred 2010**	**Audited Actual Costs Incurred 2011**	**Audited Actual Costs Incurred 2012**	**Audited Actual Costs Incurred 2013**	**Audited Actual Costs Incurred 2014**	**Audited Carrying Charges to Dec 31, 2014**	**Forecasted Costs 2015**	**Forecasted Costs 2016** [3]	**Total Costs Including Carrying Charges**	**Carrying Charges January 1, 2015 to December 31,2015/April 30, 2016 (As appropriate)**	**Total Costs and Carrying Charges**	**Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs**
professional accounting fees	$ 5,000	$ 10,000	$ -	$ 4,500	$ 1,130	$ -	$ 755	$ -	$ -	$ 21,385	$ 83	$ 21,468	Consulting Fees related to IFRS conversion
professional legal fees										$ -		$ -	
salaries, wages and benefits of staff added to support the transition to IFRS										$ -		$ -	
associated staff training and development costs										$ -		$ -	
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion								$ 5,500		$ 5,500	$ 20	$ 5,520	Carrying Charges applied to above Consulting Fees
										$ -		$ -	
										$ -		$ -	
										$ -		$ -	
										$ -		$ -	
Amounts, if any, included in previous Board approved rates (amounts should be negative) [3]				-$ 15,000			-$ 398			-$ 15,398		-$ 15,398	OEB Approved for disposition - 2012 CoS Application EB-2011-0322
										$ -		$ -	
Insert description of additional item(s) and new rows if needed.										$ -		$ -	
Total	$ 5,000	$ 10,000	$ -	-$ 10,500	$ 1,130		$ 357	$ 5,500	$ -	$ 11,487		$ 11,590	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.

2 If there were any amounts approved in previous Board approved rates, please state the EB #: EB-2011-0322

3 Any forecasted One-time costs past 2015 should be fully explained in the application, since distributors were required to adopt IFRS or an alternative accounting standard by January 1, 2015.

File Number:	EB-2015-0060
Exhibit:	8
Tab:	
Schedule:	
Page:	31
Date:	10-Aug-16

Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
Residential	Customers	1,063.00	1,063.00	1,063.00	14,291,097		$ 31.85	$ 0.0131		$ 593,491.97	$ 593,933		$ 593,933	$ 441
GS < 50 kW	Customers	152.00	152.00	152.00	4,842,432		$ 34.16	$ 0.0174		$ 146,566.16	$ 146,482		$ 146,482	-$ 84
GS > 50 to 4,999 kW	Customers	13.00	13.00	13.00	6,630,340	17,297	$ 190.92		$ 3.5672	$ 91,485.38	$ 82,795	$ 8,687	$ 91,482	-$ 3
Large Use				-						$ -			$ -	$ -
Streetlighting	Connections	328.00	328.00	328.00	267,045	724	$ 1.26		$ 5.8788	$ 9,215.61	$ 9,227		$ 9,227	$ 11
Sentinel Lighting	Connections	23.00	23.00	23.00	26,757	65	$ 13.33		$ 23.1778	$ 5,185.64	$ 5,208		$ 5,208	$ 22
Unmetered Scattered Load	Connections	4.00	4.00	4.00	3,584		$ 24.31	$ 0.0327		$ 1,284.08	$ 1,284		$ 1,284	-$ 0
Standby Power				-						$ -			$ -	$ -
Embedded Distributor Class				-						$ -			$ -	$ -
etc.				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total					26,061,255	18,086				$ 847,228.83	$ 838,929	$ 8,687	$ 847,616	$ 387

Note

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement.

2 Rates should be entered with the number of decimal places that will show on the Tariff of Rates and Charges.

File Number:	EB-2015-0060
Exhibit:	1
Tab:	
Schedule:	
Page:	43
Date:	10-Aug-16

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential	**kWh**	RPP	No	1.0654	1.0898	14,291,097	
2	GS <50 kW	**kWh**	RPP	No	1.0654	1.0898	4,842,432	
3	GS >50 kW	**kW**	Non-RPP (Other)	No	1.0654	1.0898	6,630,340	17,296
4	Street Lighting	**kW**	RPP	No	1.0654	1.0898	267,045	724
5	Sentinel Lighting	**kW**	RPP	No	1.0654	1.0898	26,757	66
6	Unmetered Scattered Load	**kWh**	RPP	No	1.0654	1.0898	3,584	
7	Rate Class 7							
8	Rate Class 8							
9	Rate Class 9							
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential	kWh	$ 17,159.26	3.1%	$ 64,319.88	14.1%	$ 78,151.09	13.4%	$ 266,619.23	11.3%
2	GS <50 kW	kWh	$ 8,516.93	5.3%	$ 13,843.60	10.6%	$ 17,907.95	10.5%	$ 115,771.98	15.0%
3	GS >50 kW	kW	-$ 12,345.57	-13.2%	-$ 38,967.57	-26.3%	-$ 42,966.41	-21.4%	-$ 37,523.41	-3.6%
4	Street Lighting	kW	-$ 23,151.05	-71.5%	-$ 19,384.55	-63.8%	-$ 19,249.16	-60.0%	-$ 13,916.82	-21.2%
5	Sentinel Lighting	kW	$ 1,828.53	54.1%	$ 1,949.05	62.3%	$ 1,961.51	59.7%	$ 3,009.58	45.2%
6	Unmetered Scattered Load	kWh	-$ 35.87	-2.7%	$ 45.82	3.6%	$ 48.83	3.8%	$ 249.28	14.6%
7	Rate Class 7									
8	Rate Class 8									
9	Rate Class 9									
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Customer Class:	**Residential**
RPP / Non-RPP:	**RPP**
Consumption	**14,291,097** kWh
Demand	**-** kW
Current Loss Factor	**1.0654**
Proposed/Approved Loss Factor	**1.0898**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	##########	1	$ 306,654.24	###########	1	$ 406,278.60	$ 99,624.36	32.49%
Smart Meter Rate Adder	Monthly	##########	1	$ 28,828.56	$ -	1	$ -	-$ 28,828.56	-100.00%
Stranded Meter Cost	Monthly	##########	1	$ 11,480.40	$ -	1	$ -	-$ 11,480.40	-100.00%
Rate Rider for Group 2 Accounts	Monthly		1	$ -	$ 5,485.0800	1	$ 5,485.08	$ 5,485.08	
Rate Rider for a/c 1575 and 1576	Monthly		1	$ -	############	1	-$ 32,934.72	-$ 32,934.72	
Rate Rider for LRAM	Monthly		1	$ -	-$ 1,844.5176	1	-$ 1,844.52	-$ 1,844.52	
Distribution Volumetric Rate	per kWh	$ 0.0140	14,291,097	$ 200,075.36	$ 0.0131	14,291,097	$ 187,213.37	-$ 12,861.99	-6.43%
Smart Meter Disposition Rider			14,291,097	$ -		14,291,097	$ -	$ -	
LRAM & SSM Rate Rider			14,291,097	$ -		14,291,097	$ -	$ -	
			14,291,097	$ -		14,291,097	$ -	$ -	
			14,291,097	$ -		14,291,097	$ -	$ -	
			14,291,097	$ -		14,291,097	$ -	$ -	
			14,291,097	$ -		14,291,097	$ -	$ -	
			14,291,097	$ -		14,291,097	$ -	$ -	
			14,291,097	$ -		14,291,097	$ -	$ -	
			14,291,097	$ -		14,291,097	$ -	$ -	
Sub-Total A (excluding pass through)				$ 547,038.56			$ 564,197.82	**$ 17,159.26**	**3.14%**
Deferral/Variance Account Disposition Rate Rider For 2012,2014,2015	per kWh	-$ 0.0069	14,291,097	-$ 98,608.57		14,291,097	$ -	$ 98,608.57	-100.00%
Rate Rider for Deferral and Variance A/Cs	per kWh		14,291,097	$ -	-$ 0.0053	14,291,097	-$ 75,742.81	-$ 75,742.81	
			14,291,097	$ -		14,291,097	$ -	$ -	
			14,291,097	$ -		14,291,097	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0006	14,291,097	$ 8,574.66	$ 0.0023	14,291,097	$ 32,869.52	$ 24,294.86	283.33%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 457,005.44**			**$ 521,325.32**	**$ 64,319.88**	**14.07%**
RTSR - Network	per kWh	$ 0.0069	15,225,735	$ 105,057.57	$ 0.0073	15,574,438	$ 113,693.39	$ 8,635.82	8.22%
RTSR - Line and Transformation Connection	per kWh	$ 0.0015	15,225,735	$ 22,838.60	$ 0.0018	15,574,438	$ 28,033.99	$ 5,195.39	22.75%
Sub-Total C - Delivery (including Sub-Total B)				**$ 584,901.61**			**$ 663,052.70**	**$ 78,151.09**	**13.36%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	15,225,735	$ 66,993.23	$ 0.0036	15,574,438	$ 56,067.98	-$ 10,925.26	-16.31%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	15,225,735	$ 19,793.46	$ 0.0013	15,574,438	$ 20,246.77	$ 453.31	2.29%
Standard Supply Service Charge	Monthly		1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)		$ 0.0070	14,291,097	$ 100,037.68					
Ontario Electricity Support Program (OESP)						15,574,438	$ -		
TOU - Off Peak	per kWh	$ 0.0800	9,744,470	$ 779,557.62	$ 0.0800	9,967,640	$ 797,411.20	$ 17,853.58	2.29%
TOU - Mid Peak	per kWh	$ 0.1220	2,740,632	$ 334,357.13	$ 0.1220	2,803,399	$ 342,014.65	$ 7,657.51	2.29%
TOU - On Peak	per kWh	$ 0.1610	2,740,632	$ 441,241.79	$ 0.1610	2,803,399	$ 451,347.20	$ 10,105.41	2.29%
Total Bill on TOU (before Taxes)				**$ 2,326,882.52**			**###########**	**$ 3,257.97**	**0.14%**
HST		13%		$ 302,494.73	13%		$ 302,918.26	$ 423.54	0.14%
Total Bill (including HST)				$ 2,629,377.25			###########	$ 3,681.50	0.14%
***Ontario Clean Energy Benefit* [1]**				-$ 262,937.73					
Total Bill on TOU				**$ 2,366,439.52**			**###########**	**$ 266,619.23**	**11.27%**

Customer Class:	**GS <50 kW**	
RPP / Non-RPP:	**RPP**	
Consumption	**4,842,432**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0654**	
Proposed/Approved Loss Factor	**1.0898**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	##########	1	$ 64,168.32	###########	1	$ 62,307.84	-$ 1,860.48	-2.90%
Smart Meter Rate Adder	Monthly	$6,000.9600	1	$ 6,000.96		1	$ -	-$ 6,000.96	-100.00%
Stranded Meter Cost	Monthly	$2,991.3600	1	$ 2,991.36		1	$ -	-$ 2,991.36	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0179	4,842,432	$ 86,679.53	$ 0.0174	4,842,432	$ 84,258.32	-$ 2,421.22	-2.79%
Smart Meter Disposition Rider			4,842,432	$ -		4,842,432	$ -	$ -	
LRAM & SSM Rate Rider			4,842,432	$ -	$ 0.0045	4,842,432	$ 21,790.94	$ 21,790.94	
			4,842,432	$ -		4,842,432	$ -	$ -	
			4,842,432	$ -		4,842,432	$ -	$ -	
			4,842,432	$ -		4,842,432	$ -	$ -	
			4,842,432	$ -		4,842,432	$ -	$ -	
			4,842,432	$ -		4,842,432	$ -	$ -	
			4,842,432	$ -		4,842,432	$ -	$ -	
			4,842,432	$ -		4,842,432	$ -	$ -	
Sub-Total A (excluding pass through)				$ 159,840.17			$ 168,357.10	**$ 8,516.93**	**5.33%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0066	4,842,432	-$ 31,960.05	-$ 0.0053	4,842,432	-$ 25,664.89	$ 6,295.16	-19.70%
Rate Rider for a/c 1575 and 1576	per kWh		4,842,432	$ -	-$ 0.0023	4,842,432	-$ 11,137.59	-$ 11,137.59	
Rate Rider for Group 2 Accounts	per kWh		4,842,432	$ -	$ 0.0004	4,842,432	$ 1,936.97	$ 1,936.97	
			4,842,432	$ -		4,842,432	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0006	4,842,432	$ 2,905.46	$ 0.0023	4,842,432	$ 11,137.59	$ 8,232.13	283.33%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	per kWh	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 130,786.37**			**$ 144,629.97**	**$ 13,843.60**	**10.58%**
RTSR - Network		$ 0.0061	5,159,127	$ 31,470.68	$ 0.0064	5,277,282	$ 33,774.61	$ 2,303.93	7.32%
RTSR - Line and Transformation Connection		$ 0.0015	5,159,127	$ 7,738.69	$ 0.0018	5,277,282	$ 9,499.11	$ 1,760.42	22.75%
Sub-Total C - Delivery (including Sub-Total B)				**$ 169,995.74**			**$ 187,903.69**	**$ 17,907.95**	**10.53%**
Wholesale Market Service Charge (WMSC)		$ 0.0044	5,159,127	$ 22,700.16	$ 0.0036	5,277,282	$ 18,998.22	-$ 3,701.94	-16.31%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	5,159,127	$ 6,706.87	$ 0.0013	5,277,282	$ 6,860.47	$ 153.60	2.29%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25		1	$ -	-$ 0.25	-100.00%
Debt Retirement Charge (DRC)		$ 0.0070	4,842,432	$ 33,897.02	$ 0.007	4,842,432	$ 33,897.02	$ -	0.00%
Ontario Electricity Support Program (OESP)						5,277,282	$ -		
TOU - Off Peak		$ 0.0800	3,301,841	$ 264,147.31	$ 0.0800	3,377,461	$ 270,196.86	$ 6,049.55	2.29%
TOU - Mid Peak		$ 0.1220	928,643	$ 113,294.43	$ 0.1220	949,911	$ 115,889.12	$ 2,594.69	2.29%
TOU - On Peak		$ 0.1610	928,643	$ 149,511.50	$ 0.1610	949,911	$ 152,935.64	$ 3,424.14	2.29%
Total Bill on TOU (before Taxes)				**$ 760,253.27**			**$ 786,681.02**	**$ 26,427.75**	**3.48%**
HST		13%		$ 98,832.93	13%		$ 102,268.53	$ 3,435.61	3.48%
Total Bill (including HST)				$ 859,086.20			$ 888,949.55	$ 29,863.36	3.48%
Ontario Clean Energy Benefit [1]				-$ 85,908.62					
Total Bill on TOU				**$ 773,177.58**			**$ 888,949.55**	**$ 115,771.98**	**14.97%**

Customer Class:	**GS >50 kW**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**6,630,340** kWh
Demand	**17,296** kW
Current Loss Factor	**1.0654**
Proposed/Approved Loss Factor	**1.0898**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	##########	1	$ 30,210.96	###########	1	$ 29,783.52	-$ 427.44	-1.41%
Smart Meter Rate Adder	Monthly	$ 951.6000	1	$ 951.60		1	$ -	-$ 951.60	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 3.6185	17,296	$ 62,585.58	$ 3.5672	17,296	$ 61,698.29	-$ 887.28	-1.42%
Smart Meter Disposition Rider			17,296	$ -		17,296	$ -	$ -	
LRAM & SSM Rate Rider	per kW		17,296	$ -	$ 0.1535	17,296	$ 2,654.94	$ 2,654.94	
Rate Rider for Group 2 Accounts	per kW		17,296	$ -	$ 0.1472	17,296	$ 2,545.97	$ 2,545.97	
Rate Rider for a/c 1575 and 1576	per kW		17,296	$ -	-$ 0.8835	17,296	-$ 15,280.15	-$ 15,280.15	
			17,296	$ -		17,296	$ -	$ -	
			17,296	$ -		17,296	$ -	$ -	
			17,296	$ -		17,296	$ -	$ -	
			17,296	$ -		17,296	$ -	$ -	
			17,296	$ -		17,296	$ -	$ -	
Sub-Total A (excluding pass through)				$ 93,748.14			$ 81,402.57	**-$ 12,345.57**	**-13.17%**
Deferral/Variance Account Disposition Rate Rider for 2012,2014,2015	per kW	-$ 2.1106	17,296	-$ 36,504.94		17,296	$ -	$ 36,504.94	-100.00%
Global Adjustment Disposition Rate Rider for 2014 and 2015	per kW	$ 5.0171	17,296	$ 86,775.76		17,296	$ -	-$ 86,775.76	-100.00%
Rate Rider for Global Adjustment	per kW		17,296	$ -	$ 2.6945	17,296	$ 46,604.07	$ 46,604.07	
Rate Rider Deferral/Variance A/C Disp.	per kW		17,296	$ -	-$ 2.0563	17,296	-$ 35,565.76	-$ 35,565.76	
Low Voltage Service Charge	per kW	$ 0.2256	17,296	$ 3,901.98	$ 0.9547	17,296	$ 16,512.49	$ 12,610.51	323.18%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 147,921.73**			**$ 108,954.16**	**-$ 38,967.57**	**-26.34%**
RTSR - Network		$ 2.5233	17,296	$ 43,643.00	$ 2.2158	17,296	$ 38,324.48	-$ 5,318.52	-12.19%
RTSR - Line and Transformation Connection		$ 0.5576	17,296	$ 9,644.25	$ 0.6339	17,296	$ 10,963.93	$ 1,319.68	13.68%
Sub-Total C - Delivery (including Sub-Total B)				**$ 201,208.97**			**$ 158,242.57**	**-$ 42,966.41**	**-21.35%**
Wholesale Market Service Charge (WMSC)		$ 0.0044	7,063,964	$ 31,081.44	$ 0.0036	7,225,745	$ 26,012.68	-$ 5,068.76	-16.31%
Rural and Remote Rate Protection (RRRP)		$ 0.0013	7,063,964	$ 9,183.15	$ 0.0013	7,225,745	$ 9,393.47	$ 210.31	2.29%
Standard Supply Service Charge		$ 39.0000	1	$ 39.00		1	$ -	-$ 39.00	-100.00%
Debt Retirement Charge (DRC)		$ 0.0070	6,630,340	$ 46,412.38	$ 0.007	6,630,340	$ 46,412.38	$ -	0.00%
Ontario Electricity Support Program (OESP)						7,225,745	$ -		
Average IESO Wholesale Market Price		$ 0.0906	7,063,964	$ 639,995.16	$ 0.0906	7,225,745	$ 654,652.45	$ 14,657.29	2.29%
Total Bill on Average IESO Wholesale Market Price				**$ 927,920.11**			**$ 894,713.55**	**-$ 33,206.56**	**-3.58%**
HST		13%		$ 120,629.61	13%		$ 116,312.76	-$ 4,316.85	-3.58%
Total Bill (including HST)				$ 1,048,549.72			###########	-$ 37,523.41	-3.58%
Ontario Clean Energy Benefit [1]				$ -					
Total Bill on Average IESO Wholesale Market Price				**$ 1,048,549.72**			**###########**	**-$ 37,523.41**	**-3.58%**

Customer Class:	**Street Lighting**
RPP / Non-RPP:	**RPP**
Consumption	**267,045** kWh
Demand	**724** kW
Current Loss Factor	**1.0654**
Proposed/Approved Loss Factor	**1.0898**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	##########	1	$ 17,436.48	$ 4,959.3600	1	$ 4,959.36	-$ 12,477.12	-71.56%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 20.6218	724	$ 14,930.18	$ 5.8788	724	$ 4,256.25	-$ 10,673.93	-71.49%
Smart Meter Disposition Rider			724	$ -		724	$ -	$ -	
LRAM & SSM Rate Rider			724	$ -		724	$ -	$ -	
			724	$ -		724	$ -	$ -	
			724	$ -		724	$ -	$ -	
			724	$ -		724	$ -	$ -	
			724	$ -		724	$ -	$ -	
			724	$ -		724	$ -	$ -	
			724	$ -		724	$ -	$ -	
			724	$ -		724	$ -	$ -	
Sub-Total A (excluding pass through)				$ 32,366.66			$ 9,215.61	**-$ 23,151.05**	**-71.53%**
Deferral/Variance Account Disposition Rate Rider for 2012,2014,2015	per kW	-$ 2.9422	724	-$ 2,130.15		724	$ -	$ 2,130.15	-100.00%
Rate Rider Deferral/Variance A/C Disp.	per kW		724	$ -	$ 2.2673	724	$ 1,641.53	$ 1,641.53	
Rate Rider for Group 2 Accounts	per kW		724	$ -	$ 0.1416	724	$ 102.52	$ 102.52	
Rate Rider for a/c 1575 and 1576	per kW		724	$ -	-$ 0.8501	724	-$ 615.44	-$ 615.44	
Low Voltage Service Charge	per kW	$ 0.2173	724	$ 157.33	$ 0.9186	724	$ 665.07	$ 507.74	322.73%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30,394.63**			**$ 11,010.08**	**-$ 19,384.55**	**-63.78%**
RTSR - Network	per kW	$ 1.9031	724	$ 1,377.84	$ 2.0311	724	$ 1,470.52	$ 92.67	6.73%
RTSR - Line and Transformation Connection	per kW	$ 0.4311	724	$ 312.12	$ 0.4901	724	$ 354.83	$ 42.72	13.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32,084.59**			**$ 12,835.42**	**-$ 19,249.16**	**-60.00%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	284,510	$ 1,251.84	$ 0.0036	291,026	$ 1,047.69	-$ 204.15	-16.31%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	284,510	$ 369.86	$ 0.0013	291,026	$ 378.33	$ 8.47	2.29%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	267,045	$ 1,869.32	$ 0.007	267,045	$ 1,869.32	$ -	0.00%
Ontario Electricity Support Program (OESP)						291,026	$ -		
TOU - Off Peak	per kWh	$ 0.0800	182,086	$ 14,566.90	$ 0.0800	186,256	$ 14,900.51	$ 333.61	2.29%
TOU - Mid Peak	per kWh	$ 0.1220	51,212	$ 6,247.83	$ 0.1220	52,385	$ 6,390.92	$ 143.09	2.29%
TOU - On Peak	per kWh	$ 0.1610	51,212	$ 8,245.09	$ 0.1610	52,385	$ 8,433.92	$ 188.83	2.29%
Total Bill on TOU (before Taxes)				**$ 64,635.43**			**$ 45,856.12**	**-$ 18,779.31**	**-29.05%**
HST		13%		$ 8,402.61	13%		$ 5,961.30	-$ 2,441.31	-29.05%
Total Bill (including HST)				$ 73,038.04			$ 51,817.42	-$ 21,220.62	-29.05%
Ontario Clean Energy Benefit [1]				-$ 7,303.80					
Total Bill on TOU				**$ 65,734.24**			**$ 51,817.42**	**-$ 13,916.82**	**-21.17%**

Customer Class:	Sentinel Lighting
RPP / Non-RPP:	RPP
Consumption	26,757 kWh
Demand	66 kW
Current Loss Factor	1.0654
Proposed/Approved Loss Factor	1.0898
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$2,387.4000	1	$ 2,387.40	$ 3,679.0800	1	$ 3,679.08	$ 1,291.68	54.10%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 15.0437	66	$ 992.88	$ 23.1778	66	$ 1,529.73	$ 536.85	54.07%
Smart Meter Disposition Rider			66	$ -		66	$ -	$ -	
LRAM & SSM Rate Rider			66	$ -		66	$ -	$ -	
			66	$ -		66	$ -	$ -	
			66	$ -		66	$ -	$ -	
			66	$ -		66	$ -	$ -	
			66	$ -		66	$ -	$ -	
			66	$ -		66	$ -	$ -	
			66	$ -		66	$ -	$ -	
			66	$ -		66	$ -	$ -	
Sub-Total A (excluding pass through)				$ 3,380.28			$ 5,208.81	**$ 1,828.53**	**54.09%**
Deferral/Variance Account Disposition Rate Rider for 2012,2014,2015	per kW	-$ 4.0189	66	-$ 265.25		66	$ -	$ 265.25	-100.00%
Rate Rider Deferral/Variance A/C Disp.	per kW		66	$ -	-$ 2.1978	66	-$ 145.05	-$ 145.05	
Rate Rider for Group 2 Accounts	per kW		66	$ -	$ 0.1556	66	$ 10.27	$ 10.27	
Rate Rider for a/c 1575 and 1576	per kW		66	$ -	-$ 0.9343	66	-$ 61.66	-$ 61.66	
Low Voltage Service Charge	per kW	$ 0.2261	66	$ 14.92	$ 1.0097	66	$ 66.64	$ 51.72	346.57%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 3,130.75**			**$ 5,079.80**	**$ 1,949.05**	**62.25%**
RTSR - Network	per kW	$ 1.9128	66	$ 126.24	$ 2.0415	66	$ 134.74	$ 8.49	6.73%
RTSR - Line and Transformation Connection	per kW	$ 0.4401	66	$ 29.05	$ 0.5003	66	$ 33.02	$ 3.97	13.68%
Sub-Total C - Delivery (including Sub-Total B)				**$ 3,286.04**			**$ 5,247.55**	**$ 1,961.51**	**59.69%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	28,507	$ 125.43	$ 0.0036	29,160	$ 104.98	-$ 20.46	-16.31%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	28,507	$ 37.06	$ 0.0013	29,160	$ 37.91	$ 0.85	2.29%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	26,757	$ 187.30	$ 0.007	26,757	$ 187.30	$ -	0.00%
Ontario Electricity Support Program (OESP)						29,160	$ -		
TOU - Off Peak	per kWh	$ 0.0800	18,244	$ 1,459.55	$ 0.0800	18,662	$ 1,492.98	$ 33.43	2.29%
TOU - Mid Peak	per kWh	$ 0.1220	5,131	$ 626.01	$ 0.1220	5,249	$ 640.35	$ 14.34	2.29%
TOU - On Peak	per kWh	$ 0.1610	5,131	$ 826.13	$ 0.1610	5,249	$ 845.05	$ 18.92	2.29%
Total Bill on TOU (before Taxes)				**$ 6,547.52**			**$ 8,556.12**	**$ 2,008.59**	**30.68%**
HST		13%		$ 851.18	13%		$ 1,112.30	$ 261.12	30.68%
Total Bill (including HST)				$ 7,398.70			$ 9,668.41	$ 2,269.71	30.68%
Ontario Clean Energy Benefit [1]				-$ 739.87					
Total Bill on TOU				**$ 6,658.83**			**$ 9,668.41**	**$ 3,009.58**	**45.20%**

Customer Class:	Unmetered Scattered Load
RPP / Non-RPP:	RPP
Consumption	3,584 kWh
Demand	- kW
Current Loss Factor	1.0654
Proposed/Approved Loss Factor	1.0898
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$1,199.5200	1	$ 1,199.52	$ 1,166.8800	1	$ 1,166.88	-$ 32.64	-2.72%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0336	3,584	$ 120.42	$ 0.0327	3,584	$ 117.20	-$ 3.23	-2.68%
Smart Meter Disposition Rider			3,584	$ -		3,584	$ -	$ -	
LRAM & SSM Rate Rider			3,584	$ -		3,584	$ -	$ -	
			3,584	$ -		3,584	$ -	$ -	
			3,584	$ -		3,584	$ -	$ -	
			3,584	$ -		3,584	$ -	$ -	
			3,584	$ -		3,584	$ -	$ -	
			3,584	$ -		3,584	$ -	$ -	
			3,584	$ -		3,584	$ -	$ -	
			3,584	$ -		3,584	$ -	$ -	
Sub-Total A (excluding pass through)				$ 1,319.94			$ 1,284.08	**-$ 35.87**	**-2.72%**
Deferral/Variance Account Disposition Rate Rider for 2012,2014,2015	per kWh	-$ 0.0221	3,584	-$ 79.21		3,584	$ -	$ 79.21	-100.00%
Rate Rider Deferral/Variance A/C Disp.	per kWh		3,584	$ -	-$ 0.0016	3,584	-$ 5.73	-$ 5.73	
Rate Rider for Group 2 Accounts	per kWh		3,584	$ -	$ 0.0004	3,584	$ 1.43	$ 1.43	
Rate Rider for a/c 1575 and 1576	per kWh		3,584	$ -	-$ 0.0023	3,584	-$ 8.24	-$ 8.24	
Low Voltage Service Charge	per kWh	$ 0.0006	3,584	$ 2.15	$ 0.0023	3,584	$ 8.24	$ 6.09	283.33%
Line Losses on Cost of Power		$ 0.1021	234	$ 23.94	$ 0.1021	322	$ 32.87	$ 8.93	37.31%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,267.62**			**$ 1,313.44**	**$ 45.82**	**3.61%**
RTSR - Network	per kWh	$ 0.0061	3,818	$ 23.29	$ 0.0064	3,906	$ 25.00	$ 1.71	7.32%
RTSR - Line and Transformation Connection	per kWh	$ 0.0015	3,818	$ 5.73	$ 0.0018	3,906	$ 7.03	$ 1.30	22.75%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,296.64**			**$ 1,345.47**	**$ 48.83**	**3.77%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	3,818	$ 16.80		3,906	$ -	-$ 16.80	-100.00%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	3,818	$ 4.96		3,906	$ -	-$ 4.96	-100.00%
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)			3,584	$ -	$ 0.007	3,584	$ 25.09	$ 25.09	
Ontario Electricity Support Program (OESP)						3,906	$ -		
TOU - Off Peak		$ 0.0800	2,294	$ 183.50	$ 0.0800	2,294	$ 183.50	$ -	0.00%
TOU - Mid Peak		$ 0.1220	645	$ 78.70	$ 0.1220	645	$ 78.70	$ -	0.00%
TOU - On Peak		$ 0.1610	645	$ 103.86	$ 0.1610	645	$ 103.86	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,684.47**			**$ 1,736.62**	**$ 52.15**	**3.10%**
HST		13%		$ 218.98	13%		$ 225.76	$ 6.78	3.10%
Total Bill (including HST)				$ 1,903.45			$ 1,962.39	$ 58.93	3.10%
Ontario Clean Energy Benefit [1]				-$ 190.35					
Total Bill on TOU				**$ 1,713.10**			**$ 1,962.39**	**$ 249.28**	**14.55%**

File Number:	EB-2015-0060
Exhibit:	1
Tab:	
Schedule:	
Page:	58
Date:	10-Aug-16

Appendix 2-Y
Summary of Impacts to Revenue Requirement from Transition to MIFRS

Revenue Requirement Component	2016 MIFRS	2016 CGAAP without policy changes	Difference	Reasons why the revenue requirement component is different under
Closing NBV 2015	$ 1,097,958	$ 984,936	$ 113,022	Depreciation Expense decrease under MIFRS Decrease in Capital under MIFRS
Closing NBV 2016	$ 1,085,835	$ 958,959	$ 126,876	Depreciation Expense decrease under MIFRS Decrease in Capital under MIFRS
Average NBV	$ 1,091,897	$ 971,948	$ 119,949	
Working Capital	$ 299,677	$ 299,677	$ -	
Rate Base	$ 1,391,574	$ 1,271,625	$ 119,949	
			0	
Return on Rate Base	$ 87,452	$ 79,914	$ 7,538	Impact of the above changes to capitalization and depreciation
			$ -	
OM&A	$ 728,300	$ 728,300	$ -	
Depreciation	$ 49,787	$ 63,640	-$ 13,853	Decrease in depreciation expense under MIFRS
PILs or Income Taxes	$ -	$ -	$ -	
			$ -	
Less: Revenue Offsets	-$ 43,505	-$ 43,505	$ -	
			$ -	
			$ -	
			$ -	
Insert description of additional item(s)			$ -	
Total Base Revenue Requirement	$ 822,034	$ 828,349	-$ 6,315	

Applicants must provide a summary of the dollar impacts of MIFRS to each component of the revenue requirement (e.g. rate base, operating costs, etc.), including the overall impact on the proposed revenue requirement. Accordingly, the applicants must identify financial differences and resulting revenue requirement impacts arising from the adoption of MIFRS as compared to CGAAP prior to capitalization and depreciation policy changes. Applicants should explain the financial differences and may separate the differences arising from changes in capitalization and depreciation policy versus the adoption of IFRS.

File Number:	EB-2015-0060
Exhibit:	8
Tab:	
Schedule:	
Page:	22
Date:	10-Aug-16

Appendix 2-Z
Proposed Tariff of Rates and Charges

For each class, Applicants are required to copy and paste the class descriptions (located directly under the class name) and the description of the applicability of those rates (description is found under the class name and directly under the word "APPLICATION"). By using the drop-down lists located under the column labeled "Rate Description", please select the descriptions of the rates and charges that BEST MATCHES the descriptions on your most recent Board-Approved Tariff of Rates and Charges. **If the description is not found in the drop-down list,** please enter the description in the green shaded cells under the correct class

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, including the MicroFit Class.

How many classes are listed on your most recent Board-Approved Tariff of Rates and Charges? 7

Identify Your Rate Classes in the **Blue Cells** below. Rate class names can be selected from the pull-dwon menu. Please ensure that a rate class is assigned to each shaded cell.

List of Rate Classes

RESIDENTIAL
GENERAL SERVICE LESS THAN 50 KW
GENERAL SERVICE 50 TO 499 KW
UNMETERED SCATTERED LOAD
SENTINEL LIGHTING
STREET LIGHTING
microFIT

Once all blue shaded cells above are filled out, press the following button to create your tariff template

Chapleau Public Utilities Corporation
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2015-0060