Ontario Energy Board

Chapter 2 Appendices
Filing Requirements for Electricity Distribution Rate Applications

Version 2.5 (2019)

Utility Name	Algoma Power Inc.
Assigned EB Number	EB-2019-0019
Name of Contact and Title	Greg Beharriell - Manager, Regulatory Affairs
Phone Number	905-871-0330 ext 3278
Email Address	regulatoryaffairs@fortisontario.com
Test Year	2020
Bridge Year	2019
Last Rebasing Year	2015
Identify the accounting standard used for the test year	MIFRS
Did you update your depreciation and capitalization policies and reflect the changes in policies in a prior rebasing application?	Yes
When did you update your actual depreciation and capitalization policies?	**January 1** **2013**
Identify the year the applicant adopted IFRS for financial reporting purposes	
Are you applying for cost recovery for the test and/or future year(s) for Green Energy initiatives?	No
Is Algoma Power Inc. an embedded distributor?	No

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

Note: Appendices for the Tariff of Rates and Charges at Current and Proposed Rates, and for the Bill Impacts are now in a separate spreadsheet model. These appendices were formerly 2-Z and 2-W.

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Appendix 2-A
List of Requested Approvals

The distributor must fill out the following sheet with the complete list of specific approvals requested and relevant section(s) of the legislation must be provided. All approvals, including accounting orders (deferral and variance accounts) new rate classes, revised specific service charges or retail service charges which the applicant is seeking, must be separately identified, as well being clearly documented in the appropriate sections of the application.

Additional requests may be added by copying and pasting blank input rows, as needed.

If additional requests arise, or requested approvals are removed, during the processing of the application, the distributor should update this list.

Algoma Power Inc. is seeking the following approvals in this application:

1		Approval to charge distribution rates effective January 1, 2020 to recover a base revenue requirement of $25,885,176, which includes a revenue deficiency of $2,192,853 as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8
2		Approval of the 2020 RRRP Adjustment Factor and the 2020 RRRP Funding amount payable to API, as described in Exhibit 8
3		Approval to adjust the Retail Transmission Rates – Network and Connection as calculated in Exhibit 8
4		Approval of the proposed loss factors as calculated in Exhibit 8
5		Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of EB-2018-0294
6		Approval of the Distribution System Plan included in Exhibit 2

7		Approval of the rate riders for disposition of the Deferral and Variance Accounts, including LRAMVA, as detailed in Exhibit 9
8		Approval for Advanced Capital Module (“ACM”) treatment of the 2021 Echo River TS Project and the 2022 Sault Facility Project, as described in Exhibit 2 and the DSP
9		Approval of API’s proposed approach for ACM cost recovery in consideration of the RRRP framework, as detailed in Section 1.3.5
10		Such other approvals that API may request and that the OEB accepts
11		**[Intentionally withdrawn June 3, 2019]**
12		Approval of API’s methodology for allocating costs attributable to the Dubreuilville service area, as summarized in Section 1.3.7
13		Approval of API’s methodologies with respect to ongoing disposition of the Interim Licence Deferral account and with respect to recovery of costs recorded in the Transaction and Integration Costs Deferral Account, both in relation to the Dubreuilville service area, as summarized in Section 1.3.7
14		Approval to resume charging Seasonal rate class customers a rate rider of $0.0307/kWh related to the Disposition of Account 1574, effective no later than January 1, 2020, as summarized in Section 1.3.8

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Appendix 2-AA
Capital Projects Table

Reporting Basis	Reporting Basis		MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	USoA	2015	2016	2017	2018	2019	2020
System Access	**System Access**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	New Meters		$63,907	$102,942	$107,367	$23,492	$48,114	$67,399
	New Cust Additions OH - Wawa		$70,247	$80,787	$73,580	$79,070	$94,195	$87,706
	New Transformers - Service		$31,139	$128,823	$42,080	$63,463	$76,800	$76,800
	New Cust Additions OH - Desb		$76,597	$232,268	$225,733	$267,189	$233,483	$224,737
	New Cust Additions UG - Desb		$269,617	$2,644	$1,927	-$820	$11,186	$11,442
	New Cust Additions OH - Sault		$187,803	$364,254	$431,992	$469,220	$391,587	$367,882
	New Cust Additions UG - Sault		$221,692	$13,743	$0	$654	$17,714	$16,562
	Miscellaneous SA		$42,142	$66,080	$495	$58,004	$39,626	$50,880
Contributed Capital								
			-$147,270	$71,036	-$78,475	-$64,304	-$140,000	-$101,850
Total System Access	**Total System Access**		**815,874**	**1,062,577**	**804,699**	**895,967**	**772,704**	**801,557**

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Appendix 2-AA
Capital Projects Table

Reporting Basis	Reporting Basis		**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Projects	Projects	**USoA**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
System Renewal	**System Renewal**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	API Storm Rebuilds - Wawa		34,817	35,339	35,514	0	40,648	40,316
	API Storm Rebuilds - Desbarats		$98,145	$34,910	$137,605	$28,979	$109,033	$98,219
	API Storm Rebuilds - Sault		$60,314	$49,516	$43,062	$31,584	$71,095	$66,797
	API Small Lines Capital - Wawa		$128,955	$192,946	$75,220	$66,815	$94,416	$103,240
	API Small Lines Capital - Desb.		$224,607	$160,132	$95,726	$171,560	$129,150	$139,178
	API Small Lines Capital - Sault		$211,995	$101,782	$144,253	$179,743	$132,132	$150,143
	API Replace Recloser, Regulator, etc.		$107,833	$101,949	$82,299	$98,453	$80,224	$81,828
	Cond Repl - Centre Line Rd. (Phase 2)		$188,406					
	Cond Repl - Neal Dr, Old Moffat Bay, Big Pit		$143,516					
	Line Rebuild - Along Hwy 17 North from MTO yard to Northwood Dr		$468,412					
	Line Rebuild - 20th Side Rd/I Line/V Line Rd SJI		$383,504					
	Pole Replacement From Pole Testing Program		$237,844	$181,083	$128,963	$430,249		
	Line Rebuild - Along Hwy 17 South of Frater Rd			$519,322				
	Line Rebuild - Shore Rd			$307,701				
	Line Rebuild - River side, Lake side off Boyles side Rd			$293,597				
	Line Rebuild - Tamawa Rd off Hwy 17N			$242,072				
	Line Rebuild - Four Seasons Drive			$183,678				
	Line Rebuild - Hillton Rd (Base Line to Hilton Beach)			$177,364				
	Line Rebuild - HWY17 Batchewana Bay P102-P129			$114,819	$164,195			
	Line Rebuild - Hwy 532 to end of line				$648,569	$157,274		
	Line Rebuild - HWY17 Wawa P1-P110				$472,635			
	Line Rebuild - Hwy 552 West				$258,639			
	Line Rebuild - B-Line				$180,631			
	Line Rebuild - Hwy17N at step up xfmr to mirian lake				$156,153	$677,496		
	Line Rebuild - Pancake to Mamainse					$604,455		
	Line Rebuild - Hwy 17W of MacLennan Rd					$343,873		
	Line Rebuild - Mackay to Rabbit Blanket - Eng					$236,772		
	Line Rebuild - 10th Side Rd (f&g to d line)					$215,151		
	Line Rebuild - F&G Line between 10th Side & A Line					$151,328		
	Line Rebuild - McKinley Ave Wawa					$114,560		
	Line Rebuilds (See DSP for Add'l Detail)						$3,380,789	$2,783,072
	Wawa 34kV Rebuild		$519,282		$191,761	$374,369		
	No 4 Circuit Rebuild		$164,270	$1,038,639	$272,240	$612,436		
	API SubTransmission Rebuilds (Small)		$72,825	$11,574	$8,270	$82,615		
	SubTransmission Rebuilds (See DSP for Add'l Detail)						$969,207	$912,061
	API NewTransf-Replace Failed/End of Life		$53,455	$18,762	$29,166	$30,203	$76,800	$76,800
	API Substation Small Capital		$61,118	$63,504	$50,034	$2,660	$60,364	$42,740
	Substation Capital - Dubr							$1,245,949
	Miscellaneous SR		$649,358	$400,231	$258,953	$360,114	$0	$24,798
Contributed Capital								
			$0	-$43,752	-$54,003	-$4,959		
Total System Renewal	**Total System Renewal**		**3,808,657**	**4,185,167**	**3,379,887**	**4,965,729**	**5,143,857**	**5,765,139**

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Appendix 2-AA
Capital Projects Table

Reporting Basis	Reporting Basis		MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Projects	Projects	USoA	2015	2016	2017	2018	2019	2020
System Service	**System Service**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	API New Transf-Volt Conv/Capacity Incr		$19,590	$62,243	$26,425	$47,180	$38,400	$38,400
	Hawk Junction DS rebuild		$2,805,052	$771,046				
	API Protection Automation Reliability		$102,675	$156,669	$16,486	$122,337	$286,944	$256,832
	API Sub/Subtrans Reliability Improvement		$105,951	$0	$16,446	$122,500	$263,346	$267,094
	API Desbarats DS Projects				$1,378	$47,016	$279,625	
	Mackay API primary metering relocation				$131,705			
Contributed Capital								
			$0	$0	$0	$0	$0	$0
Total System Service	**Total System Service**		**3,033,268**	**989,959**	**192,439**	**339,032**	**868,315**	**562,326**

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Appendix 2-AA
Capital Projects Table

Reporting Basis	Reporting Basis		**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Projects	Projects	**USoA**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
General Plant	**General Plant**		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	API Right Of Way Expansion and Access		$1,715,771	$1,554,505	$1,563,220	$1,129,615	$97,336	$99,660
	API Distribution Tools & Equipment		$45,316	$60,944	$109,172	$82,854	$94,360	$96,248
	API Vegetation Mgmt System Development		$110,660	$21,318	$437	$210		
	API Land Rights		$29,159	$30,834	$15,958	$51,962	$25,809	$28,605
	API SCADA		$51,695	$9,815	$4,916	$15,186	$93,599	$92,880
	API Transportation & Work Equipment		$437,311	$537,569	$605,784	$454,300	$621,413	$661,609
	API IT - Hardware		$178,080	$32,950	$60,354	$126,128	$149,002	$227,400
	API-Specific Engineering Soft. Develop.		$41,323	$39,713	$115,254	$114,123	$63,913	$38,980
	API Building Desbarats		$26,005	$30,667	$4,878	$875,895	$103,734	$24,154
	API Building Wawa		$326,920	$33,520	$404,370	$299,578	$154,893	$24,154
	Miscellaneous GP		$121,652	$17,308	$78,456	$90,392	$95,730	$63,028
Contributed Capital								
			-$9,848	$0	-$4,054	$0		
Total General Plant	**Total General Plant**		**3,074,045**	**2,369,143**	**2,958,744**	**3,240,243**	**1,499,788**	**1,356,717**

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TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

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

First year of Forecast Period:

2020

CATEGORY	**Historical Period** (previous plan[1] & actual)												**Forecast Period** (planned)				
	2016			2017			2018			2019			2020	2021	2022	2023	2024
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	1,020	992	-2.8%	1,020	883	-13.4%	1,020	960	-5.9%	1,020	913	-10.5%	903	963	930	906	906
System Renewal	4,834	4,229	-12.5%	4,834	3,434	-29.0%	4,834	4,971	2.8%	4,834	5,144	6.4%	5,765	4,700	4,822	6,494	4,616
System Service	538	990	84.0%	5,088	192	-96.2%	538	339	-37.0%	538	868	61.4%	562	7,978	472	461	461
General Plant	2,679	2,369	-11.6%	2,529	2,963	17.2%	2,029	3,240	59.7%	1,029	1,500	45.8%	1,357	1,238	15,408	1,178	1,098
TOTAL EXPENDITURE	9,071	8,580	-5.4%	13,471	7,472	-44.5%	8,421	9,510	12.9%	7,421	8,425	13.5%	8,588	14,879	21,632	9,039	7,081
Capital Contributions	- 100	27	-127.3%	- 100	- 137	36.5%	- 100	- 69	-30.7%	- 100	- 140	40.0%	- 102	- 100	- 100	- 100	- 100
Net Capital Expenditures	8,971	8,607	-4.1%	13,371	7,336	-45.1%	8,321	9,441	13.5%	7,321	8,285	13.2%	8,486	14,779	21,532	8,939	6,981
System O&M	$ 6,897	$ 6,361	-7.8%	$ 7,035	$ 6,715	-4.5%	$ 7,175	$ 6,712	-6.5%	$ 7,319	$ 7,016	-4.1%	$ 7,080	$ 7,186	$ 7,294	$ 7,404	$ 7,515

2015		
Plan	Actual	Var
$ '000		%
1,020	963	-5.6%
4,044	3,809	-5.8%
1,232	3,033	146.2%
2,679	3,084	15.1%
8,975	10,889	21.3%
- 100	- 157	57.1%
8,875	10,732	20.9%
$ 6,761	$ 6,296	-6.9%

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last Board-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

System Access - costs are customer-driven - declining trend in actuals results in lower budget for forecast period
System Renewal - greater number of substation rebuilds during forecast period
System Service - large substation project (Echo River TS) forecasted in 2021 (not started in 2017 as orignally planned)
General Plant - new facility construction in 2022; amounts excluding this project are lower than historical due to completion of ROW Hardening program

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

2015 - primary driver is Hawk Junction (see DSP 4.3.2.1)
2016 - underspending on SR/GP partially offset by overspending on SS
2017 - primary drivers are: Echo River TS project deferred to 2021 and Line Rebuild projects deferred to 2018 due to weather/access
2018 - primary driver is Desbarats facility (see DSP 4.3.2.3)

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

See Section 4.3.1 of DSP for Year-over-Year detail in each category.

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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.
Customer Satisfaction Surveys		
- Residential & Small Business Customer Survey 2018 (telephone)	The primary purpose of the Annual Customer Satisfaction survey is to gather information about satisfaction, customer affinity, feelings about outages and bills. Respondents are given an open-ended question to provide suggestions for improvement. For Fall 2018 additional questions around preferred method for LDC to communicate with customers when there is a billing issue or an unplanned outage. Respondents were asked about their satisfaction with their access to services and their priority rating for 12 operational issues.	Questions used in the telephone survey about communication preferences, satisfaction with access to services, and priority ratings were replicated in the Taking A.I.M. online process. Feedback and insights are used to shape the COS 5 year plan.
- Residential & Small Business Customer Survey 2017 & 2016 (telephone)	In addition to the primary purpose of the Annual Customer Satisfaction survey, feedback about the role technology plays in achieving higher levels of service for customers and making the LDC more efficient were asked. Respondents were asked to assign an importance level for 10 customer relevant technologically enabled operational items.	Algoma Power respondents are more cautious about the effect of technology on their lives than other Ontario LDC respondents. Year over year comparison, 2017 vs 2016, of the importance of online access for certain items showed growth. To make getting service easier, Algoma Power responded by putting a series of forms covering 20+ items on their website. Customers can also email customer service directly from the website. Algoma Power also added a "Make Your Voice Count" link to encourage customers to provide their opinions, views and ideas. Taking A.I.M. Chapter 6 and Chapter 7 surveys were enhanced to gather more insight into the technologically enabled operational items.
- Residential & Small Business Customer Survey 2015 (telephone)	In addition to the primary purpose of the Annual Customer Satisfaction survey, Algoma Power took the opportunity to learn more about respondent expectations as they relate to Outages and Outage Management.	Algoma Power survey respondents rate API just as favourably as found in the UtilityPULSE database for other LDCs, as it relates to having a standard of reliability that meets their expectation. However that standard is less stringent. For example 41% of UtilityPULSE database respondents indicated that 1-2 outages per year was acceptable, it was 1 in 3 (32%) for API respondents. Further follow-up on outages and outage management shaped the Taking A.I.M. Chapter 4 survey, included were questions about willingness to pay for improvements in reliability.
- Electricity Safety survey 2015	This is a standardized survey to engage consumers in Algoma Power community about electricity safety.	This was a baseline survey, Algoma results were compared with the results from 34 LDCs.
- Electricity Safety survey 2017	Second run to engage consumers about electricity safety.	Algoma Power's score of 82 was identical to the average score for 33 Ontario LDCs. In order to help educate, Algoma Power put an interactive electricity safety quiz, with supporting explainer videos, on line.
Community Outreach/Stakeholder Sessions		
Your Kilowatt Hour Sessions - provide walk-in locations for customers to have face-to-face interactions with customer service and/or CDM staff. Opportunity to edcuate customers and address any concerns. Four sessions held in primary locations.		
Your Kilowatt Hour Session - Wawa - January 11, 2018	Scheduled meetings to answer cust questions. 2 Customers made appointments but did not show due to weather conditions.	Spoke with customer about her needs over the phone (how OESP amount is determined, CDM measures, Explanation of delivery charges, Usage chart, doesn't like TOU due to being a senior with limited income and home at peak times). The other came to our office at another time wanting to understand his Equal Billing Plan.
Your Kilowatt Hour Session - Garden River-January 31, 2018	Scheduled meetings to answer cust questions. 1 Customer made appointment but did not show.	Spoke with customer about her needs over the phone.
Your Kilowatt Hour Session - Searchmont - October 10, 2018	Scheduled meetings to answer cust questions. 4 Customers made appointments.	1 cancelled as found API's website helpful to understand delivery charges and to understand her bill. Another cancelled as it worked better for her to attended our office to discuss delivery charges as a seasonal customer. Of the 2 who attended 1 wanted to understand bill (overview) and recieve energy efficiency ideas, and the other wanted to understand his bill relating to seasonal rate class.

Your Kilowatt Hour Sessions - St. Joe Island -Nov 27, 2018	Scheduled meetings to answer cust questions. 9 Customers scheduled appointments.	The topics discussed were Bill understanding, rates, delivery charges, options for electirc heat, and efficiency ideas. One microFit customer requested breakdown on how he was billed. This was provided to him three days after the event.
Annual API Contractor Night - April 25, 2018	Engage contractors to meet customer needs	Followup with contractor per individual needs
Annual Roads Superintendents Meeting	Co-ordinate work plans per municipality	Followup with Rd. Sup't per individual needs
Community Stakeholder Meeting - Nov 28, 2018	Invite all municipalities & boards with presentation covering Customer Engagement, Operations, Capital & Maintenance. Provide updates regarding: o API's Capital and Maintenance Programs 2016/17 o Stakeholdering o Capital Workflow – Road Relocations/Expansions o Vegetation Management o Forestry activities and timelines o Connection Plans o Working in Proximity, Electrical Hazards etc.	Minutes sent to all attendees after the event. A few reached out about the "Make Your Voice Count" survey.
Forestry Outreach		
- Forestry Outreach - held seven sessions to provide customers with information on API vegetation mananagement program. This forum also allowed for customers to ask questions and provide feedback.		
- Seedy Saturday SSM - March 10, 2018	Vegetation Mgmt Program display/overview: Had a table at this community event and handed out phamplets and brochures on environmental topics and cdm programs. Provided public with info on VM work program and why and how we manage vegetation	API followed up with customers to discuss vegetation management practices, property related concerns and to discuss right tree, right place providing recommendations of plant species based on site locations. API followed up with approximately 15 customers from this event.
- Sustain Algoma Expo - June 2, 2018	Vegetation Mgmt Program display/overview: Had a table at this community event and handed out phamplets and brochures on environmental topics and cdm programs. Provided public with info on VM work program and why and how we manage vegetation	API followed up with customers to discuss vegetation management practices, property related concerns and to discuss right tree, right place providing recommendations of plant species based on site locations. API followed up with approximately 15 customers from this event.
- Lower Island Lake landowner Meeting - April 5, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, 5 additional site visits resulted
- Wawa Notification Meeting Wawa – June 7, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, more site visits resulted
- Bruce Mines Community Meeting - June 25, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, 4 additional site visits resulted

- Desbarats Community Meeting - June 28, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, 4 additional site visits resulted
- Heyden, Goulais River, Batchawana Community Meeting July 16, 2018	The meeting presentations provided an overview of API's obligation and rights as an LDC to provide safe, reliable service, industry standards and best management practices and API's Vegetation Management Plan as it relates to our service territory. The meeting concluded with a question and answer period for consumers and landowners. . Handouts where provided to attendees including API's Frequently Asked Question's, Electrical Safety Authority's (ESA) brochures: ESA Tree Trimming, ESA Tree Trimming Obligations and ESA Tree Planting Guide, and Corridors for Life brochure on Right, Tree, Right Place.	Contacted individual customers who were having concerns with the VM program, 5 additional site visits resulted
CDM Outreach		
- Three sessions held to educate customers on various conservation programs while also allowing for feedback.	Through its CDM programs, API has developed a strong working relationship with a number of customers in the residential, commercial and industrial sectors.	As a result of the knowledge gained about the operations of these customers, API is able to proactively reach out to these customers as new programs become available. These customers also reach out to API to seek advice as they make their own investment decisions.
- Michipicoten High School Presentation - May 3, 2018	Wawa Energy Plan Implementation Initiative - Addresses energy efficeincy concepts and programs	Program information provided directly to attendees at the event, inclusive of application avenues and contact information.
- Wawa BIA Meeting - February 13, 2018	Presentation Re: SOE incentives for businesses, specifically the Retrofit program	Continual communication as program participation interest arises.
- Sustain Algoma Expo - June 2, 2018	Promotion of Save ON Energy suite of programs as well as the AffordAbility Fund program.	Program information provided directly to customers at the event, inclusive of application avenues and contact information.
Other Supporting Engagement Activities		
- Social Media (Outage Communication specific)	Social media consumption has been fairly low (approx 3% of total customers)	API does post outage related information via the social media channels (Twitter and Facebook) to keep following customers informed.
- Social Media (general communications)	Customer look for the latest utility, government information. Access to providing opinions and/or signing up for new programs such as e-billing	The API website is constantly responding to these requests with content updates to ensure the information is kept current with what's going on in the industry and what's important to customers
- Technology Based	Continued requests for self help portal. Information around consumption and bill payment	Myhydro Eye and e-billing information is provided to customers who subscribe to the services.
- Front Desk Support	Face to face interaction with customers has always been requested for bill payments or general inquiries	API will continue to foster this form of communication as it allows the organization to "connect" with customers.
Newsletter - sent out May and November, 2018	These Newsletters advise of Safety concerns, Engagement tools, Contests, What we are doing in our Communities, Regulatory information. November contained "Make Your Voice Count" survey information and invitation to add input. November also covered charges and rate application information in the "Legislation Corner."	There were not any inquiries API is aware of
- Social Services	Low income customers have unique needs to support payment of services.	API recognizes these needs and will make every effort to communicate special programs and/or services to support eligible customers.
Taking AIM - Customer Engagement Program		
- UtilityPULSE facilitated review of Customer Engagement activities	The purpose of this session was to: - Conduct a review of current CE activities - Leverage CE activities for gathering feedback - Identify ways to get the best from internal resources - Ensure understanding of requirements to support COS application	Clarification of roles and responsibilities between internal resources, corporate resources and third party resources as they relate to various customer engagement activities. Project time-table was also established. UtilityPULSE also lead a discussio about current industry & customer trends. Action was taken to leverage API's investment in the annual telephone customer survey to capture additional customer feedback. Topic areas for online surveys were identified.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 1	Chapter survey 1 is designed to gauge the level of respondent disposition, i.e., positive or negative, towards Algoma Power as a company. Respondents would be introduced to important concepts such as: Make Your Voice Count and Wisdom from Customers. This was a Level 1 (Informing & Information Gathering) & 2 (Gathering Feedback) engagement survey which is about raising awareness, providing education, and capturing perceptions. The primary goal of the Taking A.I.M. process is to break down a large complex topics into smaller more manageable pieces.	AP is very highly rated as a trusted and trustworthy company. This finding, along with others in Chapter 1 survey, helped shape the style and format of future chapter surveys. Respondents were given "open" space to provide feedback about the COS application, their wants & needs, and any other topic they would like to raise. Additionally, there was a second "open" space question to request contact from an AP professional.

- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 2	Chapter survey 2 is designed to gauge respondent's knowledge level about the industry. This survey is meant as an industry educational piece for respondents. Respondents were introduced to a concept called Test Your Knowledge. This was a Level 1 Engagement survey which is about raising awareness and providing education.	Knowledge level about the industry is low, the average score was 35 out of 100. However we did learn that there was no need to shy away from putting actual $$$ in costs or investments in questions. However future chapter surveys will have to take into account that the knowledge level is low.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 3	Chapter survey 3 is about gaining a better understanding of customer priorities and testing out various strategy options for dealing with issues which affects costs. This was a Level 2 (Gathering Feedback) and Level 3 (Capturing Insights by Involving Stakeholders) engagement survey. This survey also introduced respondents to a concept called Help Us Decide.	Respondents were asked to assign a priority level to 13 operational items which affect costs. Results are used to determine which items have more support by the customer base. Findings include, from respondent feedback, the majority of respondents support status quo or current standards as it relates to things such as: vegetation management. Survey results also show that current availability of call-centre staff can continue at current levels.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 4	Chapter survey 4 is about billing and outages. This is a Level 2 and Level 3 engagement survey. Bills & blackouts (outages) are known as the "Killer B's" - a very important topic for customers. Barriers to moving to e-bills were ranked by respondents. Questions about current reliability standards, expectations about the acceptable number and length of outages, and willingness to pay for an improvement in the standard of reliability was asked.	Survey results do not support a need to raise current standards are they relate to: accurately billing customers, standard of reliability, or quickly handling outages. API learned that the 2 major barriers for moving customers to e-bills was "some customers do not have access to the internet" and "some customers are not comfortable with technology". API also learned that customers much prefer telephone notification for push type of communications over other means. These findings, coupled with other findings in the Taking A.I.M. process indicates that the adoption for technology based operational improvements will be slower than LDCs in large urban areas.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 5	Chapter survey 5 is about prioritizing capital investments in the electricity network. This is a Level 2 and Level 3 engagement survey. Topics covered include: Consulting other electricity entities when planning capital expenses for the electricity network, Meeting regulatory and legal requirements, Replacing equipment, Planning for the longer term, Keeping facilities, tools, and equipment in good working order.	API's COS application is influenced by findings from consultation and interaction with other parties regarding local and regional planning issues. Findings include: System access investments should be about meeting mandated obligations and helping the community. Going forward System Renewal should be at a level that doesn't increase outages any higher than those experienced over the past 3 years. The COS application should maitain the current level of investment in facilities, tools and equipment.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 6	Chapter survey 6 is about identifying priorities and testing concepts as they relate to subjects such as: communication, customer care operations, satisfaction with information provided on things such as electricity safety, and facilities. This is a Level 3 and Level 4 (Gaining Wisdom by Participating with People) engagement survey.	Findings include a desire for more communication. API put an electricity safety quiz with explainer videos on their website. Respondents were asked about their willingness to pay for 12 Customer Care operational items, Chapter 7 questions on the same 12 items were adjusted in order to gain further insight. Findings also show that respondents would support a pragmatic approach to retro-fitting or replacing facilities.
- Taking AIM Applied Insights Methodology 7 online surveys 2018-2019 - Chapter survey 7	Chapter survey 7 is about specific DSP topics, capital and other investments in Operations and Customer Care operational changes/enhancements. This survey is a Level 3 and Level 4 engagement survey.	Decision making for API's COS application will be influenced by respondents' ranking of 9 decision-making criteria. The top three: Keep costs low. Maintain safe, reliable distribution of electricity and reduce response times to outages. Data shows there were 8% of respondents unwilling to pay any additional costs for any items such as system renewal, system service, general plant and vegetation management. Regardless of the rationale used to support COS increases, there will be a small but important respondent group who will oppose the increase. However, a clear majority support inflationary type increases.

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). Some distributors filing for 2018 rates have rebased with these accounting changes reflected in a prior rebasing application. If that is the case, information relating to pre-accounting policy changes is not generally required. The information to be provided by applicants will depend on when the accounting policy changes were made and when they last rebased. In general, applicants should provide the following information in the appendices:

		Reflecting Accounting Policy Changes in Current Application		Reflected Accounting Policy Changes in Prior Application[3]
		Accounting Policy Changes in 2012 and Adopted IFRS in 2015	**Accounting Policy Changes in 2013 and Adopted IFRS in 2015**	**Adopted IFRS in 2015**
Information to be filed in 2019 CoS Application	**2019 Test**	MIFRS	MIFRS	MIFRS
	2018 Bridge	MIFRS	MIFRS	MIFRS
	2017 Historical	MIFRS	MIFRS	MIFRS
	2016 Historical	MIFRS	MIFRS	MIFRS
	2015 Historical	MIFRS and Revised CGAAP[1]	MIFRS and Revised CGAAP[1]	MIFRS and Revised CGAAP[1]
	2014 Historical	Revised CGAAP	CGAAP and Revised CGAAP[2]	N/A
	2013 Historical	CGAAP and Revised CGAAP[2]	N/A	N/A

1) 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.

2) For applicants that are reflecting accounting policy changes for the first time in a rebasing application, the applicant must file two appendices in the year that the applicant implemented changes to its capitalization and depreciation policies (2012 or 2013), one before and one after the policy changes.

3) Applicants should provide CGAAP and Revised CGAAP schedules (i.e. as indicated in the first two columns of the above table) to support balances in Account 1576 if the account has yet to be disposed of.

<u>Appendix 2-BA - Fixed Asset Schedule</u>

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.

The applicant must establish the continuity of historic cost for gross assets and accumulated depreciation by asset class by ensuring that the opening balance in the year agrees to the closing balance in the prior year.

Appendix 2-Cx - Depreciation and Amortization

Applicants are to provide Appendix 2-C in accordance with the years and corresponding accounting standards listed in the above table.
Appendix 2-C is to be used under all three of the scenarios presented in the table above. In the appendix, the applicant will need to indicate which scenario applies. The appendix is to be duplicated for each year and accounting standard required under the scenario.
Depreciation accounting policy changes were mandated by the Board by January 1, 2013. 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. If the applicant has made any changes to its depreciation policy subsequent to the Board mandated changes, for the year of the change, applicants must complete Appendix 2-C before and after the change. Applicants must also 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) **CONTACT OEB STAFF IF TAB REQUIRED**

1) For an applicant that has a balance in Account 1576 to dispose:

- If an applicant changed capitalization and depreciation policies effective January 1, 2012, the applicant must complete Appendix 2-EB
- If an applicant changed capitalization and depreciation policies effective January 1, 2013, the applicant must complete Appendix 2-EC

2) For an applicant that has a balance in Account 1575 to dispose:

- The applicant must complete 2-EA

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.

Appendix 2-Y - Summary of Impacts to Revenue Requirement from Transition to MIFRS **CONTACT OEB STAFF IF TAB REQUIRED**

An applicant 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 applicant must identify financial differences and resulting revenue requirement impacts arising from the adoption of MIFRS as compared to CGAAP. If the applicant is reflecting the changes in capitalization and depreciation policies for the first time in a rebasing application, then a comparison between MIFRS and CGAAP before the change in accounting policies should be completed. If the applicant changed capitalization and depreciation policies and reflected these changes in a prior rebasing application, then a comparison between MIFRS and CGAAP after the change in accounting policies should be completed.

see separate workbook

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Appendix 2-BA
Fixed Asset Continuity Schedule [1]

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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,	
Parent*	**#**	**Category| Component | Type**			**MIN UL**	**TUL**	**MAX UL**			**Years**	**Rate**	**Years**	**Rate**	**Below Min TUL**	**Above Max TUL**
	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers and Fixtures	45	2%	45	2%	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								
OH	4	OH Line Switch			30	45	55	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	8	OH Conductors	Primary		50	60	75	1835	Overhead Conductors and Devices	45	2%	45	2%	Yes	No
			Service Wire			N/A		1855	Services	40	3%	40	3%	N/A	
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Line Transformers	40	3%	40	3%	No	No
	10	OH Shunt Capacitor Banks			25	30	40	1835	Overhead Conductors and Devices	45	2%	45	2%	No	Yes
	11	Reclosers			25	40	55	1835	Overhead Conductors and Devices	45	2%	45	2%	No	No
	12	Power Transformers	Overall		30	45	60	1820	Station Equipment < 50 kV	50	2%	50	2%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30	1820A	Station Equipment < 50 kV	40	3%	40	3%	No	Yes
			Battery Bank		10	15	15								
			Charger		20	20	30								
TS & MS	16	Station Metal Clad Switchgear	Overall		30	40	60	1820A	Station Equipment < 50 kV	40	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65	1820A	Station Equipment < 50 kV	40	3%	40	3%	No	No
	18	Station Switch			30	50	60	1820A	Station Equipment < 50 kV	40	3%	40	3%	No	No
	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								
	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			20	25	30	1845	UG Conductor & Devices	40	3%	40	3%	No	Yes
	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	1855	Services	40	3%	40	3%	No	No
	32	Secondary Cables in Duct			35	40	60								
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
UG	34	Pad-Mounted Transformers			25	40	45	1850	Line Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70								
	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	1980	System Supervisory Equipment	20	5%	20	5%	No	No

Table F-2 from Kinetrics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min,	
#	**Category| Component | Type**						**Years**	**Rate**	**Years**	**Rate**	**Below Min Range**	**Above Max Range**
1	Office Equipment		5	15	1915	Office Furniture & Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930A	Transportation Equipment	10	10%	10	10%	No	No
		Trailers	5	20	1930A	Transportation Equipment	10	10%	10	10%	No	No
		Vans	5	10	1930	Transportation Equipment	5	20%	5	20%	No	No
3	Administrative Buildings		50	75	1908	Buildings & Fixtures	50	2%	50	2%	No	No
4	Leasehold Improvements		Lease dependent		1910	Leasehold Improvements	5	20%	5	20%		
5	Station Buildings	Station Buildings	50	75	1808	Buildings	50	2%	50	2%	No	No
		Station Buildings - Components	N/A		1808A	Buildings - Components	25	4%	25	4%	N/A	
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Hardware	5	20%	5	20%	No	No
		Software - SAP	N/A		1611A	Computer Software	10	10%	10	10%	N/A	
		Software - Other	2	5	1611	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10	1950	Power Operated Equipment	10	10%	10	10%	No	No
		Stores	5	10								
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop & Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement & Test Equipment	10	10%	10	10%	No	No
8	Communication	Towers	60	70								
		Wireless	2	10	1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35	1860	Meters	30	3%	30	3%	No	No
10	Industrial/Commercial Energy Meters		25	35	1860	Meters	30	3%	30	3%	No	No
11	Wholesale Energy Meters		15	30	1860	Meters	30	3%	30	3%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860B	Meters	30	3%	30	3%	Yes	No
13	Smart Meters		5	15	1860A	Meters	15	7%	15	7%	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

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Appendix 2-C
Depreciation and Amortization Expense

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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	**2015 Historical Year**	**2016 Historical Year**	**2017 Historical Year**	**2018 Historical Year**	**2019 Bridge Year**	**2020 Test Year**
Operations and Maintenance	$ 7,746,765	$ 7,665,358	$ 7,852,512	$ 8,270,225	$ 8,341,726	$ 8,335,081
Billing and Collecting	$ 983,003	$ 896,275	$ 888,391	$ 939,527	$ 1,013,631	$ 1,030,997
Community Relations	$ 24,430	$ 32,308	$ 47,552	$ 141,890	$ 94,552	$ 96,558
Administrative and General	$ 4,530,641	$ 4,536,039	$ 4,495,877	$ 4,373,361	$ 4,846,021	$ 5,507,487
Total OM&A Before Capitalization (B)	$ 13,284,839	$ 13,129,980	$ 13,284,332	$ 13,725,003	$ 14,295,931	$ 14,970,123

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	2015 Historical Year	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Bridge Year	2020 Test Year	Directly Attributable? (Yes/No)	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)								
administration and other general overhead costs								
Operational Departments	$ 1,450,337	$ 1,303,871	$ 1,137,129	$ 1,558,585	$ 1,325,426	$ 1,254,834	Yes	No change since last CoS, costs are directly attributable to labour costs charged to capital and are included in burden rate. Balance includes all directly attributable costs except for direct wages. Pension and OPEB amounts capitalized are reported above.
Customer Service Department	$ 18,167	$ 20,673	$ 13,987	$ 19,592	$ 43,244	$ 35,583	Yes	No change since last CoS, costs are directly attributable to labour costs charged to capital and are included in burden rate. Balance includes all directly attributable costs except for direct wages.
Administrative and General Departments	$ 776	$ 1,532	$ 1,495	$ 12,230	$ 2,806	$ 2,519	Yes	No change since last CoS, costs are directly attributable to labour costs charged to capital and are included in burden rate. Balance includes all directly attributable costs except for direct wages.
Total Capitalized OM&A (A)	$ 1,469,280	$ 1,326,076	$ 1,152,611	$ 1,590,407	$ 1,371,476	$ 1,292,936		

% of Capitalized OM&A (=A/B)	11%	10%	9%	12%	10%	9%		

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TO BE UPDATED AT DRAFT RATE ORDER STAGE

Appendix 2-FA
Renewable Generation Connection Investment Summary (past investments or over the future rate setting period)
N/A for this Application

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 2017 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

REI Investments (Direct Benefit at 6%)	2015	2016	2017	2018	2019	Test Year 2020	2021	2022	2023	2024
Project 1										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$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	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$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	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$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	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$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	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Part B

Expansion Investments (Direct Benefit at 17%)	2015	2016	2017	2018	2019	Test Year 2020	2021	2022	2023	2024
Project 1										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$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	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$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	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$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	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$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	$0
OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

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TO BE UPDATED AT DRAFT RATE ORDER STAGE

Appendix 2-FB

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

****N/A for this Application****

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 2017 and beyond, enter variables as in the application.
Rate Riders are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

	2015			2016			2017			2018			2019		
	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	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	$ -		$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			$ -			$ -			$ -			$ -			$ -

	2020 Test Year			2021			2022			2023			2024		
	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	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	$ -		$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

Income Tax	2015		2016		2017		2018		2019	
	Direct Benefit	Provincial	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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Income Tax	2020 Test Year		2021		2022		2023		2024	
	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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Net Fixed Assets

Enter applicable amortization in years: 25

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
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

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
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	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Appendix 2-FC

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

****N/A for this Application****

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 the Test Year as these assets and costs are already in the distributor's rate base.

	2015			2016			2017			2018			2019		
	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			$ -			$ -			$ -			$ -			$ -

	2020 Test Year			2021			2022			2023			2024		
	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

	2014		2016		2017		2018		2019		2020 Test Year		2021		2022		2023		2024	
Income Tax	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial	Direct Benefit	Provincial
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

Enter applicable amortization in years: 25

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
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	2015	2016	2017	2018	2019	2020	2021	2022	2023
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	47
CCA Rate (to be entered)	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CCA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Appendix 2-G
Service Reliability and Quality Indicators
2014-2018

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days					Excluding LOS and Major Event Days				
	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018
SAIDI	12.310	19.170	6.220	15.900	13.830	10.120	16.940	5.460	11.100	11.960	8.680	11.030	6.220	12.200	9.380	7.960	8.800	5.460	7.680	7.510
SAIFI	6.470	7.120	3.850	5.970	4.260	4.040	4.400	2.570	4.260	3.140	4.930	6.390	3.850	5.150	3.310	3.240	3.680	2.570	3.950	2.200

5 Year Historical Average

SAIDI		13.486		11.116		9.502		7.482
SAIFI		5.534		3.682		4.726		3.128

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2014	2015	2016	2017	2018
Low Voltage Connections	90.0%	100.0%	100.0%	99.4%	99.2%	98.6%
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a
Telephone Accessibility	65.0%	82.6%	81.9%	86.6%	80.1%	86.1%
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%	83.3%	81.2%
Emergency Urban Response	80.0%	n/a	n/a	n/a	n/a	n/a
Emergency Rural Response	80.0%	100.0%	100.0%	100.0%	100.0%	95.7%
Telephone Call Abandon Rate	10.0%	4.8%	6.2%	3.8%	7.4%	8.3%
Appointment Scheduling	90.0%	97.2%	94.9%	98.2%	97.1%	99.0%
Rescheduling a Missed Appointment	100.0%	n/a	n/a	n/a	n/a	n/a
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

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Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2015 Actual²	2016 Actual²	2017 Actual²	2017 Actual	Bridge Year	Test Year	
		2015	2016	2017	2018	2019	2020	2015
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4235	**Specific Service Charges**	-$ 70,948	-$ 87,798	-$ 73,790	-$ 63,492	-$ 77,865	-$ 69,366	-$ 70,948
4225	**Late Payment Charges**	-$ 97,159	-$ 105,293	-$ 57,095	-$ 42,165	-$ 56,597	-$ 33,000	-$ 97,159
4082	**Retail Services Revenues**	-$ 4,961	-$ 5,061	-$ 4,710	-$ 4,599	-$ 5,030	-$ 10,060	-$ 4,961
4084	4084-Service Transaction Requests (STR) Revenues	-$ 106	-$ 56	-$ 19	-$ 34	-$ 65	-$ 129	-$ 106
4086	4086-SSS Administration Revenue	-$ 34,755	-$ 34,806	-$ 34,958	-$ 35,033	-$ 34,785	-$ 35,000	-$ 34,755
4205	4205-Interdepartmental Rents	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4210	4210-Rent from Electric Property	-$ 238,754	-$ 238,620	-$ 238,620	-$ 239,514	-$ 238,700	-$ 431,689	-$ 238,754
4215	4215-Other Utility Operating Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4220	4220-Other Electric Revenues	-$ 17,183	-$ 13,299	-$ 5,720	-$ 77,846	-$ 12,100	-$ 8,100	-$ 17,183
4240	4240-Provision for Rate Refunds	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4245	4245-Government Assistance Directly Credited to Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4305	4305-Regulatory Debits	$ 92,979	$ 92,979	$ 92,979	$ 92,979	$ 93,000	$ -	$ 92,979
4310	4310-Regulatory Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4315	4315-Revenues from Electric Plant Leased to Others	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4320	4320-Expenses of Electric Plant Leased to Others	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4324	4324-Special Purpose Charge Recovery	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4325	4325-Revenues from Merchandise Jobbing, Etc.	-$ 85,954	-$ 35,534	-$ 55,107	-$ 104,784	-$ 70,345	-$ 70,345	-$ 85,954
4330	4330-Costs and Expenses of Merchandising Jobbing, Etc.	$ 100,947	$ 71,694	$ 72,272	$ 99,063	$ 70,345	$ 70,345	$ 100,947
4335	4335-Profits and Losses from Financial Instrument Hedges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4340	4340-Profits and Losses from Financial Instrument Investments	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4345	4345-Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4350	4350-Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4355	4355-Gain on Disposition of Utility and Other Property	-$ 12,245	-$ 59,563	$ -	$ -	$ -	$ -	-$ 12,245
4360	4360-Loss on Disposition of Utility and Other Property	$ -	$ -	$ 200,067	$ 22,190	$ -	$ -	$ -
4365	4365-Gains from Disposition of Allowances for Emission	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4370	4370-Losses from Disposition of Allowances for Emission	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4375	4375-Revenues from Non-Utility Operations	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4375	4375-Sub-account Generation Facility Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4380	4380-Expenses of Non-Utility Operations	$ 525,645	$ 584,954	$ 571,402	$ 572,282	$ 546,529	$ 560,455	$ 525,645
4380	4380-Sub-account Generation Facility Expenses	$ -	$ -	$ -	$ -			$ -
4385	4385-Non-Utility Rental Income	$ -	$ -	$ -	$ -			$ -
4390	4390-Miscellaneous Non-Operating Income	-$ 37,925	$ -	$ -	$ -			-$ 37,925
4395	4395-Rate-Payer Benefit Including Interest	$ -	$ -	$ -	$ -			$ -
4398	4398-Foreign Exchange Gains and Losses, Including Amortization	$ 3,220	-$ 94	-$ 366	-$ 465			$ 3,220
4405	4405-Interest and Dividend Income	-$ 54,055	-$ 24,662	-$ 31,954	-$ 54,425	-$ 25,000	-$ 25,000	-$ 54,055
4415	4415-Equity in Earnings of Subsidiary Companies		$ -					
	Total	$ 68,748	$ 144,840	$ 434,381	$ 164,157	$ 189,388	-$ 51,889	$ 68,748
Specific Service Charges		-$ 70,948	-$ 87,798	-$ 73,790	-$ 63,492	-$ 77,865	-$ 69,366	-$ 70,948
Late Payment Charges		-$ 97,159	-$ 105,293	-$ 57,095	-$ 42,165	-$ 56,597	-$ 33,000	-$ 97,159
Other Operating Revenues		-$ 295,759	-$ 291,842	-$ 284,027	-$ 357,025	-$ 290,679	-$ 484,978	-$ 295,759
Other Income or Deductions		$ 532,613	$ 629,773	$ 849,293	$ 626,840	$ 614,529	$ 535,455	$ 532,613
Total		$ 68,748	$ 144,840	$ 434,381	$ 164,157	$ 189,388	-$ 51,889	$ 68,748

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4082, 4084, 4090, 4205, 4210, 4215, 4220, 4230, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4357, 4360, 4362, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4410, 4415, 4420

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.

	2015 Actual²	2016 Actual²	2017 Actual²	2017 Actual	Bridge Year	Test Year	0
	2015	2016	2017	2018	2019	2020	$ 2,015
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4082-Retail Services Revenues							
Monthly fixed retail charge	-$ 3,140	-$ 3,020	-$ 2,840	-$ 2,880	-$ 3,015	-$ 6,030	
Monthly variable service charge	-$ 1,160	-$ 1,282	-$ 1,170	-$ 1,079	-$ 1,268	-$ 2,536	
Bill-ready charge	-$ 661	-$ 759	-$ 701	-$ 640	-$ 747	-$ 1,494	
4084-Service Transaction Requests (STR) Revenues							
STR request fee	-$ 43	-$ 23	-$ 6	-$ 15	-$ 25	-$ 50	
STR processing fee	-$ 63	-$ 33	-$ 13	-$ 19	-$ 40	-$ 80	
4086-SSS Administration Revenue							
Administrative charge	-$ 34,755	-$ 34,806	-$ 34,958	-$ 35,033	-$ 34,785	-$ 35,000	
4210-Rent from Electric Property							
Pole rentals	-$ 238,754	-$ 238,620	-$ 238,620	-$ 239,514	-$ 238,700	-$ 431,689	
4220-Other Electric Revenues							
Returned cheque	-$ 1,618	-$ 2,062	-$ 2,655	-$ 2,445	-$ 2,100	-$ 2,100	
CDM mid-term incentive revenue	$ -	$ -	$ -	-$ 71,061	$ -	$ -	
Other	-$ 15,564	-$ 11,237	-$ 3,065	-$ 4,340	-$ 10,000	-$ 6,000	
4305-Regulatory Debits							
Return on rate base for OEB 1576	$ 92,979	$ 92,979	$ 92,979	$ 92,979	$ 93,000	$ -	
4325-Revenues from Merchandise Jobbing, Etc.							
Job order and other billable revenue	-$ 85,954	-$ 35,534	-$ 55,107	-$ 104,784	-$ 70,345	-$ 70,345	
4330-Costs and Expenses of Merchandising Jobbing, Etc.							
Job order and other billable costs	$ 100,947	$ 71,694	$ 72,272	$ 99,063	$ 70,345	$ 70,345	
4355-Gain on Disposition of Utility and Other Property							
Gains on disposals/retirements	-$ 12,245	-$ 59,563	$ -	$ -	$ -	$ -	
4360-Loss on Disposition of Utility and Other Property							
Loss on disposal of Wawa workcenter	$ -	$ -	$ 191,000	$ -	$ -	$ -	
Other	$ -	$ -	$ 9,067	$ 22,190	$ -	$ -	
4380-Expenses of Non-Utility Operations							
Shared IT asset charge from affiliate	$ 525,645	$ 584,954	$ 571,402	$ 572,282	$ 546,529	$ 560,455	
4390-Miscellaneous Non-Operating Income							
Billable (should have posted to 4325)	-$ 37,925	$ -	$ -	$ -	$ -	$ -	
4398-Foreign Exchange Gains and Losses, Including Amortization							
Gain/loss on foreign exchange	$ 3,220	-$ 94	-$ 366	-$ 465	$ -	$ -	
4405-Interest and Dividend Income							
Interest income on regulatory accounts with debit balances	-$ 23,369	-$ 13,630	-$ 9,843	-$ 16,581	$ -	$ -	
Other	-$ 30,686	-$ 11,032	-$ 22,111	-$ 37,844	-$ 25,000	-$ 25,000	
Total	$ 236,854	$ 337,932	$ 565,266	$ 269,814	$ 323,850	$ 50,477	$ -

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

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Appendix 2-I
Load Forecast CDM Adjustment Work Form (2018)

Appendix 2-I was initially 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

2018 is the fourth year of the six-year (2015-2020) Conservation First program. Final results for the 2011-14 program were issued in the fall of 2015, and the program is completed, although in

The new six year (2015-2020) CDM program works in a slightly different manner to the previous 2011-2014 CDM program. Distributors will offer programs each year that, over the six years (from

2015-2020 CDM Program - 2018 fourth 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. This results in each year's program being about 1/6

6 Year (2015-2020) kWh Target:							
7,510,000							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
%							
2015 CDM Programs						8.27%	14.34%
2016 CDM Programs						10.96%	19.01%
2017 CDM Programs						17.13%	29.72%
2018 CDM Programs						55.53%	96.37%
2019 CDM Programs						3.91%	6.78%
2020 CDM Programs						4.21%	7.31%
Total in Year						**100.00%**	**173.54%**
kWh							
2015 CDM Programs	1,077,169.00	1,068,894.00	1,068,387.00	1,093,167.00	1,086,232.00	1,077,279.00	1,077,279.00
2016 CDM Programs		1,437,693.00	1,437,694.00	1,437,694.00	1,437,694.00	1,427,961.00	1,427,961.00
2017 CDM Programs			2,640,268.00	2,250,773.00	2,248,143.00	2,232,142.00	2,232,142.00
2018 CDM Programs				7,237,615.43	7,237,615.43	7,237,615.43	7,237,615.43
2019 CDM Programs					509,000.00	509,000.00	509,000.00
2020 CDM Programs						549,000.00	549,000.00
Total in Year	**1,077,169.00**	**2,506,587.00**	**5,146,349.00**	**12,019,249.43**	**12,518,684.43**	**13,032,997.43**	**7,510,000.00**

Inputs do no match 2015-20 CDM

Note: The default formulae in the above table assume that the 2015-2020 kWh CDM target is achieved through persistence of CDM savings to the end of 2020. The distributor should enter

Determination of 2018 Load Forecast Adjustment

The Board 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

From each of the 2006-2010 CDM Final Report, and the 2011 to 2016 CDM Final Reports, issued by the OPA/IESO for the distributor, the distributor should input the "gross" and "net" results of the

Net-to-Gross Conversion

Is CDM adjustment being done on a "net" or "gross" basis?				**net**
Persistence of Historical CDM programs to 2015	**"Gross" kWh**	**"Net" kWh**	**Difference kWh**	**"Net-to-Gross" Conversion Factor ('g')**
2006-2010 CDM programs				
2011 CDM program				
2012 CDM program				
2013 CDM program				
2014 CDM program				
2015 CDM program				
2016 CDM program				
2006 to 2016 OPA CDM programs: Persistence to 2018.	0	0	0	0.00%

The default values below represent the factor used for how each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1"

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 historical years

Weight Factor for Inclusion in CDM Adjustment to 2018 Load Forecast

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	
Weight Factor for each year's CDM program impact on 2018 load forecast	**0**	**0**	**0**	**1**	**0.5**	**1**	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Full year impact of 2015 CDM is assumed to be reflected in the base forecast, as the full year persistence of 2015 CDM programs is in the 2016 historical actual data. No further impact is necessary for the manual adjustment to the load forecast.*	*Default is 0.5, but one option is for full year impact of persistence of 2016 CDM programs on 2018 load forecast, but 50% impact in base forecast (first year impact of 2016 CDM programs on 2016 actuals, which is part of the data underlying the base load forecast).*	*Full year impact of persistence of 2017 programs on 2018 load forecast. 2017 CDM program impacts are not in the base forecast.*	*Only 50% of 2017 CDM programs are assumed to impact the 2018 load forecast based on the "half-year" rule.*	*2019 and 2020 are future years beyond the 2018 test year. No impacts of CDM programs beyond the 2018 test year are factored into the test year load forecast.*		

2015-2020 LRAMVA and 2018 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2018 load forecast is made. There is a different but related threshold amount that is used for the 2018 LRAMVA amount for Account 1568.

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 2018, for assessing performance against the six-year target.

If used to determine the manual CDM adjustment for the system purchased kWh, the proposed loss factor should correspond with the proposed total loss factor calculated in Appendix 2-R .

The Manual Adjustment for the 2018 Load Forecast is the amount manually subtracted from the system-wide load forecast (either based on a purchased or billed basis) 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 a 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 IESO-measured impacts were directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2015	2016	2017	2018	2019	2020	Total for 2020
Amount used for CDM threshold for LRAMVA (2020)				7,237,615.43	509,000.00	549,000.00	**8,295,615.43**
Manual Adjustment for 2018 Load Forecast (billed basis)	-			7,237,615.43	254,500.00	549,000.00	8,041,115.43
Manual Adjustment for 2018 LDC-only CDM programs (billed basis)							
Total Manual Forecast to Load Forecast	-	-	-	7,237,615.43	254,500.00	549,000.00	**8,041,115.43**
Proposed Loss Factor (TLF)	8.29%	Format: X.XX%					
Manual Adjustment for 2018 Load Forecast (system purchased basis)	-	-	-	7,837,613.75	275,598.05	594,512.10	**8,707,723.90**

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

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Appendix 2-IA
Instructions on Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet requires no inputs, but serves as a summary of the hiostorical and forecasted data to be provided with respect to:

1) Customers and connections
2) Consumption (kWh)
3) Demand (kW or kCA) for applicable demand-billed customer classes
4) Revenues

The spreadsheet summarizes the data provided and the analyses (variance or year-over-year) that are required. Data are required to be provided on a customer class level. Consumption (kWh) must also be provided on a total distribution system level.

Appendix 2-IB (formerly 2-IA) is the appendix spreadsheet that the distributor populates, and the spreadsheet is laid out for inputting the necessary data. The spreadsheet also calculates necessary statistics such as average consumption per customer/connection per year, and variances and % annual changes, as necessary.

The distributor is required to provide suitable documentation in Exhibit 3 of its Application, in accordance with section 2.3.2 of Chaoter 2 of the Filing Requirements. This would include explanations for material variations or of trends in the data.

The distributor is also required to input its test year customer/connection and load forecast in Sheet 10 - Load Forecast of the Revenue Requirement Work Form. This sheet should also be updated to reflect changes in the load forecast made through the stages of processing of the rates application.

The applicant must demonstrate the historical accuracy of its load forecast approach for at least the past 5 years. Such analysis will cover both customer/connections and consumption (kWh) and demand (kW or kVA) by providing the following, as shown in the following table:

	Calendar Year (for 2020 Cost of Service)	Customers / Connections		Consumption (kWh) [3]			Demand (kW or kVA)			Revenues	
				Weather-actual	Weather-normalized		Weather-actual	Weather-normalized		Weather-actual	Weather-normalized
Historical	2014	Actual		Actual	Actual [1]		Actual	Actual [1]		Actual	
Historical	2015	Actual		Actual	Actual [1]		Actual	Actual [1]		Actual	
Historical	2016	Actual	Board-approved [2]	Actual	Actual [1]	Board-approved [2]	Actual	Actual [1]	Board-approved [2]	Actual	
Historical	2017	Actual		Actual	Actual [1]		Actual	Actual [1]		Actual	
Historical	2018	Actual		Actual	Actual [1]		Actual	Actual [1]		Actual	
Bridge Year (Forecast)	2019	Forecast			Forecast			Forecast			Forecast
Test Year (Forecast)	2020	Forecast			Forecast			Forecast			Forecast

Notes:

(1) "Weather-normalized actuals" are estimated by replacing the actual weather-related values (typically Heating Degree Days (HDD) and Cooling Degree Days (CDD)) by the "typical" or "weather-normalized" values. These "weather-normalized HDD and CDD values would be the same as used to estimate the Bridge Year and Test Year forecasts.

(2) For 2017 Cost of Service rebasers, the typical situation is that 2013 would have been the most recent cost of service rebasing application. If the most recent rebasing application was for a rate year other than 2013, that year should be used. An applicant must provide historical information back to the greater of: a) at least five (5) historical actual years; or b) to its last cost of service application.

(3) Consumption must be provided on a total distribution system basis as well as at a customer class level.

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Appendix 2-IB
Customer, Connections, Load Forecast and Revenues Data and Analysis

This sheet is to be filled in accordance with the instructions documented in section 2.3.2 of Chapter 2 of the Filing Requirements for Distribution Rate Applications, in terms of one set of tables per customer class.

Color coding for Cells: Data input; Drop-down List; No data entry required; Blank or calculated value

Distribution System (Total)

	Calendar Year (for 2020 Cost of Service		Consumption (kWh) (3)				
				Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2014*		Actual	222844848	217052675		
Historical	*2015*		Actual	216436884	211935646	Board-approved	217540073
Historical	*2016*		Actual	211050246	208497216		
Historical	*2017*		Actual	217280995	209640368		
Historical	*2018*		Actual	241087151	218759530		
Bridge Year	*2019*		Forecast		214173157		
Test Year	*2020*		Forecast		214241143		

Variance Analysis	Year	Year-over-year			Versus Board-approved
	2014				
	2015	-2.9%	-2.4%		
	2016	-2.5%	-1.6%		
	2017	3.0%	0.5%		
	2018	11.0%	4.3%		
	2019		-2.1%		
	2020		0.0%		-1.5%
	Geometric Mean	2.7%	-0.3%		-0.4%

Customer Class Analysis (one for each Customer Class, excluding MicroFIT and Standby)

1 Customer Class: R1(i) Residential

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)		Customers		
Historical	*2014*	Actual	7,398		
Historical	*2015*	Actual	7,480	Board-approved	7531
Historical	*2016*	Actual	7,544		
Historical	*2017*	Actual	7,596		
Historical	*2018*	Actual	7,640		
Bridge Year	*2019*	Forecast	7,722		
Test Year	*2020*	Forecast	8,116		

Calendar Year		Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
2014	Actual	85393126	84657660		
2015	Actual	80876150	80925127	Board-approved	80045884
2016	Actual	75910136	76877138		
2017	Actual	76321856	75502253		
2018	Actual	82834418	77001847		
2019	Forecast		75387475		
2020	Forecast		79805566		

Calendar Year		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
2014	Actual	11542.861	11443.446		
2015	Actual	10813.042	10819.5905	Board-approved	10628.85195
2016	Actual	10062.653	10190.8385		
2017	Actual	10047.087	9939.19315		
2018	Actual	10842.556	10079.1056		
2019	Forecast	0	9763.06702		
2020	Forecast	0	9833.68602		

Variance Analysis

Year	Customers Year-over-year	Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2014								
2015	1.1%		-5.3%	-4.4%		-6.3%	-5.5%	
2016	0.9%		-6.1%	-5.0%		-6.9%	-5.8%	
2017	0.7%		0.5%	-1.8%		-0.2%	-2.5%	
2018	0.6%		8.5%	2.0%		7.9%	1.4%	
2019	1.1%			-2.1%			-3.1%	
2020	5.1%	7.8%		5.9%	-0.3%		0.7%	-7.5%
Geometric Mean	1.9%	1.9%	-1.0%	-1.2%	-0.1%	-2.1%	-3.0%	-1.9%

	Calendar Year (for 2020 Cost of Service)		Revenues		
Historical	*2014*	Actual	$ 4,831,306		
Historical	*2015*	Actual	$ 4,747,596	Board-approved	$ 4,734,787
Historical	*2016*	Actual	$ 4,699,186		
Historical	*2017*	Actual	$ 4,885,574		
Historical	*2018*	Actual	$ 5,184,809		
Bridge Year (Foreca	*2019*	Forecast	$ 5,209,713		
Test Year (Forecast)	*2020*	Forecast	$ 5,582,146		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2014		
2015	-1.7%	
2016	-1.0%	
2017	4.0%	
2018	6.1%	
2019	0.5%	
2020	7.1%	17.9%
Geometric Mean	2.9%	4.2%

2 **Customer Class:** R1(ii) GS < 50 kW

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service	Customers			
Historical	*2014*	Actual	956		
Historical	*2015*	Actual	954	Board-approved	
Historical	*2016*	Actual	951		
Historical	*2017*	Actual	961		
Historical	*2018*	Actual	961		
Bridge Year	*2019*	Forecast	956		
Test Year	*2020*	Forecast	997		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	27212831	26978455		
Actual	26130351	26146175	Board-approved	25745817
Actual	24984442	25302713		
Actual	25604789	25329825		
Actual	26240994	24393302		
Forecast		23881888		
Forecast		26928875		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	28475.233	28229.984		
Actual	27383.129	27399.712	Board-approved	
Actual	26267.155	26601.7662		
Actual	26639.281	26353.2078		
Actual	27308.293	25385.4502		
Forecast	0	24978.3307		
Forecast	0	27001.3487		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2014		
2015	-0.1%	
2016	-0.3%	
2017	1.1%	
2018	0.0%	
2019	-0.5%	
2020	4.3%	
Geometric Mean	0.9%	

Year	Year-over-year		Test Year Versus Board-approved
2014			
2015	-4.0%	-3.1%	
2016	-4.4%	-3.2%	
2017	2.5%	0.1%	
2018	2.5%	-3.7%	
2019		-2.1%	
2020		12.8%	4.6%
Geometric Mean	-1.2%	0.0%	1.1%

Year	Year-over-year		Test Year Versus Board-approved
2014			
2015	-3.8%	-2.9%	
2016	-4.1%	-2.9%	
2017	1.4%	-0.9%	
2018	2.5%	-3.7%	
2019		-1.6%	
2020		8.1%	
Geometric Mean	-1.4%	-0.9%	

	Calendar Year (for 2020 Cost of Service	Revenues			
Historical	*2014*	Actual	$ 1,150,016		
Historical	*2015*	Actual	$ 1,124,342	Board-approved	$ 1,114,740
Historical	*2016*	Actual	$ 1,105,677		
Historical	*2017*	Actual	$ 1,162,926		
Historical	*2018*	Actual	$ 1,215,505		
Bridge Year (Foreca	*2019*	Forecast	$ 1,156,310		
Test Year (Forecast)	*2020*	Forecast	$ 1,254,063		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2014		
2015	-2.2%	
2016	-1.7%	
2017	5.2%	
2018	4.5%	
2019	-4.9%	
2020	8.5%	12.5%
Geometric Mean	1.7%	3.0%

3 Customer Class: R2 GS>50 kW

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2020 Cost of Service)		Customers		
Historical	2014	Actual	43		
Historical	2015	Actual	42	Board-approved	
Historical	2016	Actual	42		
Historical	2017	Actual	38		
Historical	2018	Actual	40		
Bridge Year	2019	Forecast	39		
Test Year	2020	Forecast	37		

Consumption (kWh) [3]				
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	83470708	82751799		
Actual	86528984	86581384	Board-approved	83288188
Actual	89578886	90720011		
Actual	94512143	93497198		
Actual	109202680	101513457		
Forecast		99385190		
Forecast		91043719		

Consumption (kWh) per Customer				
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	1922549.9	1905991.52		
Actual	2052070.8	2053313.46	Board-approved	
Actual	2128607.2	2155723.04		
Actual	2476300.7	2449708.25		
Actual	2747237.2	2553797.65		
Forecast	0	2547736.72		
Forecast	0	2442014.41		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2014		
	2015	-2.9%	
	2016	-0.2%	
	2017	-9.3%	
	2018	4.1%	
	2019	-1.9%	
	2020	-4.4%	
	Geometric Mean	-3.0%	

Year	Year-over-year		Test Year Versus Board-approved
2014			
2015	3.7%	4.6%	
2016	3.5%	4.8%	
2017	5.5%	3.1%	
2018	15.5%	8.6%	
2019		-2.1%	
2020		-8.4%	9.3%
Geometric Mean	9.4%	1.9%	2.3%

Year	Year-over-year		Test Year Versus Board-approved
2014			
2015	6.7%	7.7%	
2016	3.7%	5.0%	
2017	16.3%	13.6%	
2018	10.9%	4.2%	
2019		-0.2%	
2020		-4.1%	
Geometric Mean	12.6%	5.1%	

	Calendar Year (for 2020 Cost of Service)		Revenues		
Historical	2014	Actual	$ 918,089		
Historical	2015	Actual	$ 952,357	Board-approved	$ 979,697
Historical	2016	Actual	$ 997,741		
Historical	2017	Actual	$ 976,358		
Historical	2018	Actual	$ 1,093,385		
Bridge Year (Foreca	2019	Forecast	$ 1,093,775		
Test Year (Forecast)	2020	Forecast	$ 989,147		

Demand (kW)				
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	196688	194994		
Actual	208261	208387	Board-approved	198901
Actual	217369	220138		
Actual	210836	208572		
Actual	234800	218267		
Forecast		229529		
Forecast		210264		

Demand (kW) per Customer				
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	0.2142364	0.21239121		
Actual	0.2186795	0.21881191	Board-approved	0.203023037
Actual	0.2178607	0.22063602		
Actual	0.2159414	0.21362243		
Actual	0.2147459	0.19962509		
Forecast	0	0.20984994		
Forecast	0	0.21257124		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2014		
	2015	3.7%	
	2016	4.8%	
	2017	-2.1%	
	2018	12.0%	
	2019	0.0%	
	2020	-9.6%	1.0%
	Geometric Mean	1.5%	0.2%

Year	Year-over-year		Test Year Versus Board-approved
2014			
2015	5.9%	6.9%	
2016	4.4%	5.6%	
2017	-3.0%	-5.3%	
2018	11.4%	4.6%	
2019		5.2%	
2020		-8.4%	5.7%
Geometric Mean	6.1%	1.5%	1.4%

Year	Year-over-year		Test Year Versus Board-approved
2014			
2015	2.1%	3.0%	
2016	-0.4%	0.8%	
2017	-0.9%	-3.2%	
2018	-0.6%	-6.6%	
2019		5.1%	
2020		1.3%	4.7%
Geometric Mean	0.1%	0.0%	1.2%

4 **Customer Class:** Seasonal   Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)	Customers				Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2014*	Actual	3,255			Actual	7919568	7851359			Actual	2433.4208	2412.46245		
Historical	*2015*	Actual	3,176	Board-approved		Actual	6868390	6872549	Board-approved	7731414	Actual	2162.6481	2163.95772	Board-approved	
Historical	*2016*	Actual	3,140			Actual	6205026	6284070			Actual	1976.1754	2001.34944		
Historical	*2017*	Actual	3,108			Actual	6042453	5977564			Actual	1944.1091	1923.23172		
Historical	*2018*	Actual	3,076			Actual	6043635	5618088			Actual	1964.5048	1826.1793		
Bridge Year	*2019*	Forecast	3,018			Forecast		5500303			Forecast	#VALUE!	1822.65537		
Test Year	*2020*	Forecast	2,960			Forecast		5502049			Forecast	#VALUE!	1858.68368		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2014			*2014*				*2014*			
	2015	-2.4%		*2015*	-13.3%	-12.5%		*2015*	-11.1%	-10.3%	
	2016	-1.1%		*2016*	-9.7%	-8.6%		*2016*	-8.6%	-7.5%	
	2017	-1.0%		*2017*	-2.6%	-4.9%		*2017*	-1.6%	-3.9%	
	2018	-1.0%		*2018*	0.0%	-6.0%		*2018*	1.0%	-5.0%	
	2019	-1.9%		*2019*		-2.1%		*2019*		-0.2%	
	2020	-1.9%		*2020*		0.0%	-28.8%	*2020*		2.0%	
	Geometric Mean	-1.9%		Geometric Mean	-8.6%	-6.9%	-8.2%	Geometric Mean	-6.9%	-5.1%	

	Calendar Year (for 2020 Cost of Service)	Revenues			
Historical	*2014*	Actual	$ 1,859,618		
Historical	*2015*	Actual	$ 2,038,872	Board-approved	$ 2,152,693
Historical	*2016*	Actual	$ 2,181,681		
Historical	*2017*	Actual	$ 2,420,339		
Historical	*2018*	Actual	$ 2,656,334		
Bridge Year (Foreca	*2019*	Forecast	$ 2,804,402		
Test Year (Forecast)	*2020*	Forecast	$ 3,013,255		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2014		
	2015	9.6%	
	2016	7.0%	
	2017	10.9%	
	2018	9.8%	
	2019	5.6%	
	2020	7.4%	40.0%
	Geometric Mean	10.1%	8.8%

5 **Customer Class:** Street Lighting

Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2020 Cost of Service)		Customers		
Historical	*2014*	Actual	1,019		
Historical	*2015*	Actual	1,023	Board-approved	
Historical	*2016*	Actual	1,066		
Historical	*2017*	Actual	1,070		
Historical	*2018*	Actual	1,067		
Bridge Year	*2019*	Forecast	1,067		
Test Year	*2020*	Forecast	1,117		

	Calendar Year (for 2020 Cost of Service)		Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2014*	Actual	777269	777269		
Historical	*2015*	Actual	742696	742696	Board-approved	804705
Historical	*2016*	Actual	584575	584575		
Historical	*2017*	Actual	582537	582537		
Historical	*2018*	Actual	568784	568784		
Bridge Year	*2019*	Forecast		568784		
Test Year	*2020*	Forecast		595435		

	Calendar Year (for 2020 Cost of Service)		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2014*	Actual	763.08798	763.087982		
Historical	*2015*	Actual	726.23497	726.234974	Board-approved	
Historical	*2016*	Actual	548.21075	548.210753		
Historical	*2017*	Actual	544.42682	544.426822		
Historical	*2018*	Actual	533.02658	533.026585		
Bridge Year	*2019*	Forecast	0	533.026585		
Test Year	*2020*	Forecast	0	533.026585		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2014		
	2015	0.4%	
	2016	4.3%	
	2017	0.3%	
	2018	-0.3%	
	2019	0.0%	
	2020	4.7%	
	Geometric Mean	1.9%	

Year	Year-over-year		Test Year Versus Board-approved
2014			
2015	-4.4%	-4.4%	
2016	-21.3%	-21.3%	
2017	-0.3%	-0.3%	
2018	-2.4%	-2.4%	
2019		0.0%	
2020		4.7%	-26.0%
Geometric Mean	-9.9%	-5.2%	-7.3%

Year	Year-over-year		Test Year Versus Board-approved
2014			
2015	-4.8%	-4.8%	
2016	-24.5%	-24.5%	
2017	-0.7%	-0.7%	
2018	-2.1%	-2.1%	
2019		0.0%	
2020		0.0%	
Geometric Mean	-11.3%	-6.9%	

	Calendar Year (for 2020 Cost of Service)		Revenues		
Historical	*2014*	Actual	$ 134,709		
Historical	*2015*	Actual	$ 144,734	Board-approved	$ 155,629
Historical	*2016*	Actual	$ 143,649		
Historical	*2017*	Actual	$ 158,229		
Historical	*2018*	Actual	$ 199,870		
Bridge Year (Foreca	*2019*	Forecast	$ 214,518		
Test Year (Forecast)	*2020*	Forecast	$ 216,079		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2014		
	2015	7.4%	
	2016	-0.7%	
	2017	10.2%	
	2018	26.3%	
	2019	7.3%	
	2020	0.7%	38.8%
	Geometric Mean	9.9%	8.6%

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

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Appendix 2-JA

Summary of Recoverable OM&A Expenses

	2015		2016		2017		2018	2019	2020
	2015 Last Rebasing Year Board Approved	**2015 Last Rebasing Year Actuals**	**2016 Board Approved**	**2016 Actuals**	**2017 Board Approved**	**2017 Actuals**	**2018 Actuals**	**2019 Bridge Year**	**2020 Test Year**
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Operations	$ 1,642,392	$ 1,417,407		$ 1,296,572		$ 1,451,821	$ 1,566,232	$ 1,790,341	$ 1,782,437
Maintenance	$ 5,118,954	$ 4,879,021		$ 5,064,915		$ 5,263,562	$ 5,145,408	$ 5,225,959	$ 5,297,810
SubTotal	**$ 6,761,346**	**$ 6,296,428**	**$ -**	**$ 6,361,487**	**$ -**	**$ 6,715,383**	**$ 6,711,640**	**$ 7,016,300**	**$ 7,080,247**
%Change (year over year)		-6.9%		1.0%		5.6%	-0.1%	4.5%	0.9%
%Change (Test Year vs Last Rebasing Year - Actual)									12.4%
Billing and Collecting	$ 1,090,942	$ 964,836		$ 875,602		$ 874,404	$ 919,935	$ 970,387	$ 995,414
Community Relations	$ 22,102	$ 24,430		$ 32,308		$ 47,552	$ 141,890	$ 94,552	$ 96,558
Administrative and General	$ 4,430,491	$ 4,529,865		$ 4,534,507		$ 4,494,382	$ 4,361,131	$ 4,843,215	$ 5,504,968
SubTotal	**$ 5,543,535**	**$ 5,519,131**	**$ -**	**$ 5,442,417**	**$ -**	**$ 5,416,338**	**$ 5,422,956**	**$ 5,908,154**	**$ 6,596,940**
%Change (year over year)		-0.4%		-1.4%		-0.5%	0.1%	8.9%	11.7%
%Change (Test Year vs Last Rebasing Year - Actual)									19.5%
Total	**$ 12,304,881**	**$ 11,815,559**	**$ -**	**$ 11,803,904**	**$ -**	**$ 12,131,721**	**$ 12,134,596**	**$ 12,924,455**	**$ 13,677,187**
%Change (year over year)		-4.0%		-0.1%		2.8%	0.0%	6.5%	5.8%

Note:

1 Historical actuals going back to the last cost of service application are required to be entered by the applicant.
2 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.

	2015				2016			2017		2018		2019		2020	
	Last Rebasing Year 2015 Board Approved	Last Rebasing Year 2015 Actuals	Variance 2015 Board Approved - 2015 Actuals	2016 Board Approved	2016 Actuals	Variance 2016 Actuals - 2015 Actuals	2017 Board Approved	2017 Actuals	Variance 2017 Actuals - 2016 Actuals	2018 Actuals	Variance 2018 Acutals vs. 2017 Actuals	2019 Bridge Year	Variance 2019 Bridge vs. 2018 Actuals	2020 Test Year	Variance 2020 Test vs. 2019 Bridge
Operations	**$ 1,642,392**	**$ 1,417,407**	**$ 224,985**	**$ -**	**$ 1,296,572**	**-$ 120,835**	**$ -**	**$ 1,451,821**	**$ 155,249**	**$ 1,566,232**	**$ 114,411**	**$ 1,790,341**	**$ 224,109**	**$ 1,782,437**	**-$ 7,904**
Maintenance	**$ 5,118,954**	**$ 4,879,021**	**$ 239,933**	**$ -**	**$ 5,064,915**	**$ 185,893**	**$ -**	**$ 5,263,562**	**$ 198,647**	**$ 5,145,408**	**-$ 118,154**	**$ 5,225,959**	**$ 80,551**	**$ 5,297,810**	**$ 71,850**
Billing and Collecting	**$ 1,090,942**	**$ 964,836**	**$ 126,106**	**$ -**	**$ 875,602**	**-$ 89,235**	**$ -**	**$ 874,404**	**-$ 1,197**	**$ 919,935**	**$ 45,531**	**$ 970,387**	**$ 50,452**	**$ 995,414**	**$ 25,027**
Community Relations	**$ 22,102**	**$ 24,430**	**-$ 2,328**	**$ -**	**$ 32,308**	**$ 7,879**	**$ -**	**$ 47,552**	**$ 15,244**	**$ 141,890**	**$ 94,338**	**$ 94,552**	**-$ 47,338**	**$ 96,558**	**$ 2,006**
Administrative and General	**$ 4,430,491**	**$ 4,529,865**	**-$ 99,374**	**$ -**	**$ 4,534,507**	**$ 4,642**	**$ -**	**$ 4,494,382**	**-$ 40,125**	**$ 4,361,131**	**-$ 133,250**	**$ 4,843,215**	**$ 482,084**	**$ 5,504,968**	**$ 661,753**
Total OM&A Expenses	**$ 12,304,881**	**$ 11,815,559**	**$ 489,322**	**$ -**	**$ 11,803,904**	**-$ 11,655**	**$ -**	**$ 12,131,721**	**$ 327,818**	**$ 12,134,596**	**$ 2,875**	**$ 12,924,455**	**$ 789,858**	**$ 13,677,187**	**$ 752,733**
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)						**$ -**									
Total Recoverable OM&A Expenses	**$ 12,304,881**	**$ 11,815,559**	**$ 489,322**	**$ -**	**$ 11,803,904**	**-$ 11,655**	**$ -**	**$ 12,131,721**	**$ 327,818**	**$ 12,134,596**	**$ 2,875**	**$ 12,924,455**	**$ 789,858**	**$ 13,677,187**	**$ 752,733**
Variance from previous year					-$ 11,655			$ 327,818		$ 2,875		$ 789,858		$ 752,733	
Percent change (year over year)					0%			3%		0%		7%		6%	
Percent Change: Test year vs. Most Current Actual															12.7%
Simple average of % variance for all years															3.0%
Compound Annual Growth Rate for all years															3.0%

Last Rebasing Year (2015 Approved)	**2015 Actuals**	**Last Rebasing Year (2016 Board Approved)**		**2016 Actuals**	**Last Rebasing Year (2017 Board Approved)**	**2017 Actuals**	**2018 Actuals**	**2019 Bridge Year**	**2020 Test Year**
$ 1,642,392	$ 1,417,407	$ -		$ 1,296,572	$ -	$ 1,451,821	$ 1,566,232	$ 1,790,341	$ 1,782,437
$ 5,118,954	$ 4,879,021	$ -		$ 5,064,915	$ -	$ 5,263,562	$ 5,145,408	$ 5,225,959	$ 5,297,810
$ 1,090,942	$ 964,836	$ -		$ 875,602	$ -	$ 874,404	$ 919,935	$ 970,387	$ 995,414
$ 22,102	$ 24,430	$ -		$ 32,308	$ -	$ 47,552	$ 141,890	$ 94,552	$ 96,558
$ 4,430,491	$ 4,529,865	$ -		$ 4,534,507	$ -	$ 4,494,382	$ 4,361,131	$ 4,843,215	$ 5,504,968
$ 12,304,881	**$ 11,815,559**	**$ -**		**$ 11,803,904**	**$ -**	**$ 12,131,721**	**$ 12,134,596**	**$ 12,924,455**	**$ 13,677,187**
0.0%				-0.1%		2.8%	0.0%	6.5%	5.8%

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Appendix 2-JB
Recoverable OM&A Cost Driver Table[1,3]

OM&A	**Last Rebasing Year (2015 Actuals)**	**2016 Actuals**	**2017 Actuals**	**2018 Actuals**	**2019 Bridge Year**	**2020 Test Year**
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Opening Balance[2]	$ 12,304,881	$ 11,815,559	$ 11,803,904	$ 12,131,721	$ 12,134,596	$ 12,924,455
Vehicle Depreciation Credit	$ 258,000					
Load Dispatching	-$ 66,000					
AMI Metering Costs	-$ 44,000	$ 33,000	$ 38,000			
Outages	-$ 148,000	$ 121,000	$ 147,000	-$ 273,000		
Right of Way Maintenance Program	-$ 70,000	$ 116,000	$ 62,000	$ 207,000		
Miscellaneous Customer Accounts Expenses	-$ 89,000	-$ 52,000	-$ 13,000	$ 77,000		
G&A Outside Services Employed	-$ 80,000	$ 231,000	-$ 122,000			
Technical Services Supervisor Vacancy		-$ 47,000	$ 47,000			
Overhead Lines and Feeders Maintenance - Labour		-$ 48,000	$ 30,000	$ 23,000	$ 22,000	
Regional Manager		-$ 148,000	$ 110,000	$ 25,000		
Utilityperson Hire			-$ 60,000	-$ 60,000	$ 105,000	
Customer Engagement				$ 109,000	-$ 74,000	
Maintenance on Poles, Towers and Fixtures, and Overhead Conductors and Devices				-$ 44,000	$ 78,000	
Joint Use Pole Rental Paid					$ 40,000	
Right of Way Land Fees					$ 47,000	
Sault Ste Marie Building Rent						$ 341,000
Regulatory Expenses						$ 155,000
Shared Services Administrative Services From CNPI Distribution			$ 116,000	-$ 214,000	$ 294,000	$ 71,000
Dubreuilville Interim License Internal Effort			-$ 109,000	$ 40,000	$ 19,000	$ 50,000
Miscellaneous	-$ 250,322	-$ 217,655	$ 81,817	$ 112,875	$ 258,859	$ 135,732
Closing Balance[2]	$ 11,815,559	$ 11,803,904	$ 12,131,721	$ 12,134,596	$ 12,924,455	$ 13,677,187

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is requied in Exhibit 4.

2 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount. 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 four 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 four years ago, a minimum of three years of actual information is required.

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Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2015 Board-Approved)	Last Rebasing Year (2015 Actuals)	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year	Variance (Test Year vs. 2018 Actuals)	Variance (Test Year vs. Last Rebasing Year (2015 Board-
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Customer Focus									
Customer Service, Mailing Costs, Billing and Collections, LEAP	908,819	809,242	728,128	721,552	779,344	849,591	848,296	68,951	-60,523
Community Relations	22,102	24,430	32,308	47,552	141,890	94,552	96,558	-45,332	74,456
Bad Debts	100,000	64,251	62,004	49,190	43,555	71,000	71,000	27,445	-29,000
Meter Reading	106,363	115,582	117,111	131,602	124,976	77,735	104,058	-20,918	-2,305
								0	0
								0	0
Sub-Total	1,137,284	1,013,505	939,551	949,897	1,089,765	1,092,879	1,119,912	30,147	-17,372
Operational Effectiveness									
Stations	329,020	243,664	169,781	141,119	198,821	190,271	201,225	2,404	-127,795
Load Dispatching	106,000	39,766	40,668	127,237	135,356	157,587	165,702	30,346	59,702
Supervision and Engineering	209,996	196,955	166,716	206,344	281,939	300,320	246,582	-35,357	36,586
Meters Maintenance	839,470	755,168	776,309	835,155	752,357	844,549	846,103	93,746	6,633
Overhead Lines and Feeders	1,287,589	1,202,398	1,307,560	1,425,626	1,157,007	1,258,908	1,321,533	164,526	33,944
Distribution Transformers	27,197	16,045	10,937	2,776	3,520	15,413	17,446	13,926	-9,751
Right of Way Maintenance Program	3,301,180	3,231,088	3,346,741	3,409,082	3,616,124	3,578,067	3,571,764	-44,360	270,584
Underground Lines, Feeders, and Services	37,102	13,552	2,964	9,927	10,293	12,530	14,466	4,173	-22,636
Poles Towers & Fixtures	174,034	127,827	150,750	121,217	101,801	129,056	130,195	28,395	-43,839
Salaries, Wages and Benefits for Administrative Services	2,484,276	2,704,652	2,521,175	2,621,314	2,510,807	2,966,460	3,080,168	569,361	595,892
Other External Administrative Services	478,490	398,334	629,516	507,229	512,310	434,790	441,194	-71,116	-37,296
Rent and Maintenance of General Plant	869,183	836,940	858,254	868,096	886,554	903,530	1,287,715	401,161	418,532
Other Operating and Maintenance	449,758	469,965	389,061	436,901	454,422	529,601	565,230	110,808	115,472
Other General and Admin	358,416	324,708	295,860	314,599	292,394	358,915	361,170	68,776	2,754
								0	0
Sub-Total	10,951,711	10,561,062	10,666,290	11,026,620	10,913,705	11,679,996	12,250,493	1,336,788	1,298,782
Public and Regulatory Responsiveness									
Regulatory & Compliance	215,886	240,992	198,062	155,204	131,127	151,580	306,783	175,656	90,897
								0	0
								0	0
								0	0
								0	0
Miscellaneous								0	0
Total	**12,304,881**	**11,815,559**	**11,803,904**	**12,131,721**	**12,134,596**	**12,924,455**	**13,677,187**	**1,542,591**	**1,372,306**

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

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Appendix 2-K
Employee Costs

	Last Rebasing Year (2015 Board Approved)	Last Rebasing Year (2015 Board Approved Restated)	2015 Actuals	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Number of Employees (FTEs including Part-Time)[1]								
Management (including executive)	15	15	12	11	10	11	11	11
Non-Management (union and non-union)	66	59	59	59	59	58	60	59
Total	81	74	71	70	69	69	71	70
Total Salary and Wages including ovetime and incentive pay								
Management (including executive)	$ 1,663,095	$ 1,663,095	$ 1,593,050	$ 1,527,913	$ 1,365,026	$ 1,464,209	$ 1,560,527	$ 1,608,679
Non-Management (union and non-union)	$ 4,722,845	$ 4,722,845	$ 5,066,718	$ 5,078,369	$ 5,090,533	$ 5,427,381	$ 5,671,376	$ 5,843,490
Total	$ 6,385,940	$ 6,385,940	$ 6,659,768	$ 6,606,283	$ 6,455,559	$ 6,891,590	$ 7,231,903	$ 7,452,169
Total Benefits (Current + Accrued)								
Management (including executive)	$ 645,642	$ 645,642	$ 446,204	$ 359,625	$ 358,614	$ 388,910	$ 403,538	$ 367,350
Non-Management (union and non-union)	$ 2,112,645	$ 2,112,645	$ 2,106,901	$ 1,687,039	$ 1,888,383	$ 1,966,521	$ 2,080,049	$ 1,760,359
Total	$ 2,758,287	$ 2,758,287	$ 2,553,105	$ 2,046,664	$ 2,246,996	$ 2,355,431	$ 2,483,587	$ 2,127,710
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$ 2,308,737	$ 2,308,737	$ 2,039,254	$ 1,887,539	$ 1,723,640	$ 1,853,120	$ 1,964,065	$ 1,976,029
Non-Management (union and non-union)	$ 6,835,490	$ 6,835,490	$ 7,173,619	$ 6,765,408	$ 6,978,916	$ 7,393,902	$ 7,751,424	$ 7,603,850
Total	$ 9,144,227	$ 9,144,227	$ 9,212,873	$ 8,652,947	$ 8,702,556	$ 9,247,021	$ 9,715,489	$ 9,579,879

Note:

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

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Appendix 2-L

Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year - 2015- Board Approved	Last Rebasing Year - 2015- Actual	2016 Actuals	2017 Actuals	2018 Actuals	2019 Bridge Year	2020 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs							
O&M	$6,761,346	$6,296,428	$6,361,487	$6,715,383	$6,711,640	$7,016,300	$7,080,247
Admin Expenses	$5,543,535	$5,519,131	$5,442,417	$5,416,338	$5,422,956	$5,908,154	$6,596,940
Total Recoverable OM&A from	$12,304,881	$11,815,559	$11,803,904	$12,131,721	$12,134,596	$12,924,455	$13,677,187
Number of Customers [2,4]	11,684	11,652	11,677	11,704	11,717	11,735	12,110
Number of FTEs [3,4]	74	71	70	69	69	71	70
Customers/FTEs	157.89	164.11	166.81	169.62	169.81	165.28	173.00
OM&A cost per customer							
O&M per customer	$579	$540	$545	$574	$573	$598	$585
Admin per customer	$474	$474	$466	$463	$463	$503	$545
Total OM&A per customer	$1,053	$1,014	$1,011	$1,037	$1,036	$1,101	$1,129
OM&A cost per FTE							
O&M per FTE	$91,370	$88,682	$90,878	$97,324	$97,270	$98,821	$101,146
Admin per FTE	$74,913	$77,734	$77,749	$78,498	$78,594	$83,213	$94,242
Total OM&A per FTE	$166,282	$166,416	$168,627	$175,822	$175,864	$182,035	$195,388

Notes:

1. If it has been more than four 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 four years ago, a minimum of three years of actual information is required.
2. The method of calculating the number of customers must be identified. Should correspond with data provided in Appendix 2-IB.
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.
5. For the test year, the applicant should take into account the system O&M (line 22 of Appendix 2-AB) in developing its forecasted OM&A.

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TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

Appendix 2-M
Regulatory Cost Schedule

#	Regulatory Cost Category	USoA Account	USoA Account Balance	Last Rebasing Year (2015 Board Approved)	Last Rebasing Year (2015 Actual)	Most Current Actuals Year 2018	2019 Bridge Year	Annual % Change	2020 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=[(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
	Regulatory Costs (Ongoing)									
1	OEB Annual Assessment	5655		$ 115,000	$ 123,037	$ 50,464	$ 70,800	40.30%	$ 71,904	1.56%
2	OEB Section 30 Costs (OEB-initiated)	5655		$ 1,000	$ 10,946	$ 1,641	$ 5,496	234.97%	$ 5,416	-1.46%
3	Expert Witness costs for regulatory matters	5655								
4	Legal costs for regulatory matters	5655			$ 3,875		$ 1,475			-100.00%
5	Consultants' costs for regulatory matters	5655								
6	Operating expenses associated with staff resources allocated to regulatory matters	5655		$ 53,886	$ 58,504	$ 34,393	$ 29,180	-15.16%	$ 48,459	66.07%
7	Operating expenses associated with other resources allocated to regulatory matters [1]	5655								
8	Other regulatory agency fees or assessments	5655								
9	Any other costs for regulatory matters (please define) - Amortization of 2015 Approved One-Time Costs	5655			$ 44,629	$ 44,629	$ 44,629	0.00%		-100.00%
10	Intervenor costs	5655								
11	OEB Section 30 Costs (Applicant-Originated)	5655		$ 1,000						
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Regulatory Costs (One-Time)									
1	Expert Witness costs	5655								
2	Legal costs	5655		$ 110,000					$ 110,000	
3	Consultants' costs	5655		$ 40,000					$ 73,500	
4	Incremental operating expenses associated with staff resources allocated to this application.	5655								
5	Incremental operating expenses associated with other resources allocated to this application. [1]	5655								
6	Intervenor costs	5655		$ 75,000					$ 130,000	
7	OEB Section 30 Costs (application-related)	5655								
8	Customer Engagment and Other costs	5655							$ 40,000	
9	Recovery of Transaction and Integration Deferral Account (EB-2018-0271)	5655							$ 551,520	
10										
11										
12										
13										
14										
15										
1	Sub-total - Ongoing Costs [2]		$ -	$ 170,886	$ 240,992	$ 131,127	$ 151,580	15.60%	$ 125,779	-17.02%
2	Sub-total - One-time Costs [3]		$ -	$ 225,000	$ -	$ -	$ -		$ 905,020	
3	Total (Ongoing + 1/5 of One-Time)		$ -	$ 215,886	$ 240,992	$ 131,127	$ 151,580	15.60%	$ 306,783	102.39%

Application-Related One-Time Costs	Total (2020)	Total (2015)
Total One-Time Costs Related to Application to be Amortized over IRM Period	$ 905,020	$ 225,000
1/5 of Total One-Time Costs	$ 181,004	$ 45,000

Notes:

[1] Please identify the resources involved.
[2] Sum of all ongoing costs.
[3] Sum of all one-time costs.

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Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: **2015 Board Approved**

Shared Services

***combined shared services and corporate

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$

Shared Services and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FortisOntario	API	corporate services	cost based	22%	451,532
FortisOntario	API	building rent	market based	13%	70,123
CNPI-Distribution	API	administrative services	cost based	24%	1,418,934
Fortis Inc.	API	administrative services	cost based	1%	99,820

Year: **2015**

Shared Services

***combined shared services and corporate

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$

Shared Services and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FortisOntario	API	corporate services	cost based	22%	447,185
FortisOntario	API	building rent	market based	13%	70,123
CNPI-Distribution	API	administrative services	cost based	24%	1,426,761
CNPI-Distribution	API	shared IT	cost based	34%	525,645
Fortis Inc.	API	administrative services	cost based	1%	137,075

Year: **2016**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$

Shared Services and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FortisOntario	API	corporate services	cost based	22%	469,380
FortisOntario	API	building rent	market based	13%	71,525
CNPI-Distribution	API	administrative services	cost based	24%	1,398,626
CNPI-Distribution	API	shared IT	cost based	34%	584,954
Fortis Inc.	API	administrative services	cost based	1%	182,070

Year: **2017**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$

Shared Services and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FortisOntario	API	corporate services	cost based	22%	493,618
FortisOntario	API	building rent	market based	14%	77,411
CNPI-Distribution	API	administrative services	cost based	25%	1,515,070
CNPI-Distribution	API	shared IT	cost based	35%	571,402
Fortis Inc.	API	administrative services	cost based	1%	159,750

Year: **2018**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$

Shared Services and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FortisOntario	API	corporate services	cost based	22%	479,140
FortisOntario	API	building rent	market based	14%	78,959
CNPI-Distribution	API	administrative services	cost based	25%	1,301,192
CNPI-Distribution	API	shared IT	cost based	35%	572,282
Fortis Inc.	API	administrative services	cost based	1%	170,800

Year: **2019**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$

Shared Services and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FortisOntario	API	corporate services	cost based	22%	521,540
FortisOntario	API	building rent	market based	14%	80,539
CNPI-Distribution	API	administrative services	cost based	25%	1,594,811
CNPI-Distribution	API	shared IT	cost based	35%	546,529
Fortis Inc.	API	administrative services	cost based	1%	173,838

Year: **2020**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$

Shared Services and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
FortisOntario	API	corporate services	cost based	22%	534,579
FortisOntario	API	building rent	market based	14%	82,552
CNPI-Distribution	API	administrative services	cost based	25%	1,665,334
CNPI-Distribution	API	shared IT	cost based	35%	560,455
Fortis Inc.	API	administrative services	cost based	1%	189,234

Shared Services and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	2015 Board Approved	2018	2020	Variance (2020 Test vs 2018)	Variance (2020 Test vs 2015 Board Approved)
From	To			Amount Allocated	Amount Allocated	Amount Allocated	Amount Allocated	Amount Allocated
				$	$	$	$	$
FortisOntario	API	corporate services	cost based	451,532	479,140	534,579	55,439	83,047
FortisOntario	API	building rent	market based	70,123	78,959	82,552	3,593	12,429
CNPI-Distribution	API	administrative services	cost based	1,418,934	1,301,192	1,665,334	364,143	246,400
CNPI-Distribution	API	shared IT	cost based	-	572,282	560,455	- 11,827	560,455
Fortis Inc.	API	administrative services	cost based	99,820	170,800	189,234	18,434	89,414

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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: **2020** **Test Year**

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$67,129,125	4.95%	$3,322,892
2	Short-term Debt	4.00%	(1)	$4,794,938	2.82%	$135,217
3	**Total Debt**	60.0%		$71,924,063	4.81%	$3,458,109
	Equity					
4	Common Equity	40.00%		$47,949,375	8.98%	$4,305,854
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$47,949,375	8.98%	$4,305,854
7	**Total**	100.0%		$119,873,438	6.48%	$7,763,963

Year: **2019**

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$64,281,570	5.15%	$3,310,501
2	Short-term Debt	4.00%	(1)	$4,591,541	2.16%	$99,177
3	**Total Debt**	60.0%		$68,873,110	4.95%	$3,409,678
	Equity					
4	Common Equity	40.00%		$45,915,407	9.30%	$4,270,133
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$45,915,407	9.30%	$4,270,133
7	**Total**	100.0%		$114,788,517	6.69%	$7,679,811

Year: 2018

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$61,101,222	5.15%	$3,146,713
2	Short-term Debt	4.00%	(1)	$4,364,373	2.16%	$94,270
3	**Total Debt**	60.0%		$65,465,595	4.95%	$3,240,983
	Equity					
4	Common Equity	40.00%		$43,643,730	9.30%	$4,058,867
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$43,643,730	9.30%	$4,058,867
7	**Total**	100.0%		$109,109,325	6.69%	$7,299,850

Year: 2017

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$59,335,537	5.15%	$3,055,780
2	Short-term Debt	4.00%	(1)	$4,238,253	2.16%	$91,546
3	**Total Debt**	60.0%		$63,573,789	4.95%	$3,147,326
	Equity					
4	Common Equity	40.00%		$42,382,526	9.30%	$3,941,575
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$42,382,526	9.30%	$3,941,575
7	**Total**	100.0%		$105,956,315	6.69%	$7,088,901

Year: 2016

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$57,169,259	5.15%	$2,944,217
2	Short-term Debt	4.00%	(1)	$4,083,519	2.16%	$88,204
3	**Total Debt**	60.0%		$61,252,778	4.95%	$3,032,421
	Equity					
4	Common Equity	40.00%		$40,835,185	9.30%	$3,797,672
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$40,835,185	9.30%	$3,797,672
7	**Total**	100.0%		$102,087,963	6.69%	$6,830,093

Year: **2015**

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$53,718,994	5.15%	$2,766,528
2	Short-term Debt	4.00%	(1)	$3,837,071	2.16%	$82,881
3	**Total Debt**	60.0%		$57,556,065	4.95%	$2,849,409
	Equity					
4	Common Equity	40.00%		$38,370,710	9.30%	$3,568,476
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$38,370,710	9.30%	$3,568,476
7	**Total**	100.0%		$95,926,775	6.69%	$6,417,885

Year: **2015** **Board Approved**

Line No.	Particulars	Capitalization Ratio			Cost Rate	Return
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$54,920,225	5.15%	$2,828,392
2	Short-term Debt	4.00%	(1)	$3,922,873	2.16%	$84,734
3	**Total Debt**	60.0%		$58,843,099	4.95%	$2,913,126
	Equity					
4	Common Equity	40.00%		$39,228,732	9.30%	$3,648,272
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$39,228,732	9.30%	$3,648,272
7	**Total**	100.0%		$98,071,831	6.69%	$6,561,398

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Appendix 2-OB
Debt Instruments

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

Year **2020**

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Senior Unsecured Notes	Life Insurance Cos.	Third-Party	Fixed Rate	16/Dec/11	30	$ 52,000,000	5.118%	$ 2,661,360.00	
2	Debt Issue Costs								$ 16,632.00	$498,968 over 30 yrs
3	Promissory Note	FortisOntario Inc.	Affiliated	Variable Rate	17/Dec/18	Demand	$ 12,750,000	4.130%	$ 526,575.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 64,750,000	4.95%	$ 3,204,567.00	

Year 2019

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Senior Unsecured Notes	Life Insurance Cos.	Third-Party	Fixed Rate	16/Dec/11	30	$ 52,000,000	5.118%	$ 2,661,360.00	
2	Debt Issue Costs								$ 16,632.00	$498,968 over 30 yrs
3	Promissory Note	FortisOntario Inc.	Affiliated	Variable Rate	17/Dec/18	Demand	$ 12,750,000	4.130%	$ 526,575.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 64,750,000	4.95%	$ 3,204,567.00	

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Senior Unsecured Notes	Life Insurance Cos.	Third-Party	Fixed Rate	16/Dec/11	30	$ 52,000,000	5.118%	$ 2,661,360.00	
2	Debt Issue Costs								$ 16,632.00	$498,968 over 30 yrs
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 52,000,000	5.15%	$ 2,677,992.00	

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Senior Unsecured Notes	Life Insurance Cos.	Third-Party	Fixed Rate	16/Dec/11	30	$ 52,000,000	5.118%	$ 2,661,360.00	
2	Debt Issue Costs								$ 16,632.00	$498,968 over 30 yrs
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 52,000,000	5.15%	$ 2,677,992.00	

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Senior Unsecured Notes	Life Insurance Cos.	Third-Party	Fixed Rate	16/Dec/11	30	$ 52,000,000	5.118%	$ 2,661,360.00	
2	Debt Issue Costs								$ 16,632.00	$498,968 over 30 yrs
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 52,000,000	5.15%	$ 2,677,992.00	

Year 2015

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	Senior Unsecured Notes	Life Insurance Cos.	Third-Party	Fixed Rate	16/Dec/11	30	$ 52,000,000	5.118%	$ 2,661,360.00	
2	Debt Issue Costs								$ 16,632.00	$498,968 over 30 yrs
3									$ -	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 52,000,000	5.15%	$ 2,677,992.00	

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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 on Sheet 11 of the RRWF.)

****N/A for Algoma Power****

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	

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Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2014	2015	2016	2017	2018	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	224,055,026	218,359,584	213,114,845	219,147,652	243,134,751	223,562,371
A(2)	"Wholesale" kWh delivered to distributor (lower value)	223,056,717	217,389,981	212,169,174	218,174,267	242,054,719	222,568,972
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	223,056,717	217,389,981	212,169,174	218,174,267	242,054,719	222,568,972
D	"Retail" kWh delivered by distributor	205,806,696	200,913,700	197,489,288	203,142,174	224,890,511	206,448,474
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	-	-	-	-	-	-
F	Net "Retail" kWh delivered by distributor = **D - E**	205,806,696	200,913,700	197,489,288	203,142,174	224,890,511	206,448,474
G	Loss Factor in Distributor's system = **C / F**	1.0838	1.0820	1.0743	1.0740	1.0763	1.0781
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0887	1.0869	1.0792	1.0788	1.0812	1.0829

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 One Networks' invoice.

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-WEB.

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 provided in Hydro One Networks' invoice.

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 **I** 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 calculated as the weighted average of above.

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

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Appendix 2-S
Stranded Meter Treatment
N/A for this Application

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					$ -		$ -
2009					$ -		$ -
2010					$ -		$ -
2011					$ -		$ -
2012					$ -		$ -
2013					$ -		$ -
2014					$ -		$ -
2015					$ -		$ -
2016					$ -		$ -
2017	(1)				$ -		$ -

Notes:

(1) *For 2017, 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.

In the green shaded cell (row 18-26) enter the most recent 12-month actual data. If there is a material difference between actual and forecasted consumption data, use forecasted data and provide an explanation

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Commodity Expense

Step 1: **Allocation of Commodity**

2017 Historical Actuals

Customer Class Name		Last Actual kWh's	Class A kWh	Class B kWh	non-RPP non GA mod	non-RPP GA mod	non-RPP Total	RPP	Proportions (by Class) non-RPP %	Proportions (by Class) RPP %	
Residential R1		101,926,645		101,926,645	-	3,966,000	3,966,000	97,960,645	*3.89%*	*96.11%*	
Residential R2		94,512,143	-	94,512,143	89,444,000	2,003,000	91,447,000	3,065,143	*96.76%*	*3.24%*	
Seasonal		6,042,453		6,042,453	-	27,000	27,000	6,015,453	*0.45%*	*99.55%*	
Street Lighting		582,537		582,537	-	583,000	583,000	(463)	*100.08%*	*-0.08%*	
other				-	-	-	-	0	*#DIV/0!*	*#DIV/0!*	
other				-	-		-	0	*#DIV/0!*	*#DIV/0!*	
other				-	-		-	0	*#DIV/0!*	*#DIV/0!*	
other				-				0			
other				-				0			
TOTAL		**203,063,778**	**0**	**203,063,778**	**89,444,000**	**6,579,000**	**96,023,000**	**107,040,778**			
%		*100.00%*		*100.00%*	*44.05%*	*3.24%*		*52.71%*	*47.29%*	*52.71%*	*100.00%*

Step 2: **Forecasted Commodity Prices**

Step 2a: **GA Modifier** ($/MWh) — non-RPP: $ (44.38) Source: Table 1: RPP Prices and GA Modifier: May 1, 2018 to April 30, 2019*

Step 2b: **Forecasted Commodity Prices** Table 1: Average RPP Supply Cost Summary**

			non-RPP non GA mod	non-RPP GA mod	RPP
HOEP ($/MWh)	Load-Weighted Price for RPP Consumers		$19.64	$19.64	
Global Adjustment ($/MWh)	Impact of the Global Adjustment		$103.80	$59.42	
Adjustments ($/MWh)			$1.00	$1.00	
TOTAL ($/MWh)	Average Supply Cost for RPP Consumers		**$124.44**	**$80.06**	**$82.00**
$/kWh			***$0.12444***	***$0.08006***	***$0.08200***
Percentage shares (%)	non-RPP (GA mod/non-GA mod), RPP		44.05%	3.24%	52.71%
WEIGHTED AVERAGE PRICE ($/kWh)	**(Sum of I43, J43 and L43)**	$ 0.1006	**$0.0548**	**$0.0026**	**$0.0432**

Step 3: **Commodity Expense**

(volumes for the bridge and test year are loss adjusted)

Class A

Customer		Revenue	Expense	2018 kWh Volume	2018 kW Volume	2018 HOEP Rate/kWh	2018 Avg GA/kW	2018 Amount	2019 kWh Volume	2019 kW Volume	2019 HOEP Rate/kWh	2019 Avg GA/kW	2019 Amount
Seasonal		4035	4705			0.01964		$0			0.01964		$0
Street Lighting		4010	4705	81,086,629	131,588	0.01964	20.238	$4,255,619	81,086,629	131,588	0.01964	20.238	$4,255,619
				81,086,629	131588			$4,255,619					$4,255,619

Class B

Customer Class Name	UoM	Revenue USA #	Expense USA #	2018 Volume	2018 rate ($/kWh):	2018 Amount	2019 Volume	2019 rate ($/kWh):	2019 Amount
Residential R1	kWh	4006	4705	108,372,364	0.1006	$10,902,260	112,547,683	$0.1006	$11,325,763
Residential R2	kWh	4010	4705	27,412,183	0.1006	$2,757,666	11,899,814	$0.1006	$1,197,488
Seasonal	kWh	4035	4705	6,004,681	0.1006	$604,071	5,890,288	$0.1006	$592,744
Street Lighting	kWh	4010	4705	620,941	0.1006	$62,467	644,797	$0.1006	$64,886
other	kWh	4025	4705		0.1006	$0		$0.1006	$0
other	kWh	4025	4705		0.1006	$0		$0.1006	$0
other	kWh	4025	4705		0.1006	$0		$0.1006	$0
other	kWh	4025	4705		0.1006	$0		$0.1006	$0
other	kWh	4025	4705		0.1006	$0		$0.1006	$0
TOTAL				**142,410,169**		**$14,326,463**	**130,982,582**		**$13,180,881**

Total

Customer Class Name	UoM	Revenue USA #	Expense USA #	2017 Volume	2017 avg rate ($/kWh):	2017 Amount	2018 Volume	2018 avg rate ($/kWh):	2018 Amount
Residential R1	kWh	4006	4705	108,372,364	0.1006	$10,902,260	112,547,683	0.1006	$11,325,763
Residential R2	kWh	4010	4705	27,412,183	0.1006	$2,757,666	11,899,814	0.1006	$1,197,488
Seasonal	kWh	4035	4705	6,004,681	0.1006	$604,071	5,890,288	0.1006	$592,744
Street Lighting	kWh	4010	4705	81,707,570	0.0528	$4,318,086	81,731,426	0.0529	$4,320,505
other	kWh	4025	4705	0	#DIV/0!	$0	0	#DIV/0!	$0
other	kWh	4025	4705	0	#DIV/0!	$0	0	#DIV/0!	$0
other	kWh	4025	4705	0	#DIV/0!	$0	0	#DIV/0!	$0
other	kWh	4025	4705	0	0	$0	0	0.0000	$0
other	kWh	4025	4705	0	0	$0	0	0.0000	$0
TOTAL				**223,496,798**		**$18,582,082**	**212,069,211**		**$17,436,500**

**Regulated Price Plan Prices and the Global Adjustment Modifier for the Period May 1, 2018 – April 30, 2019*

*** Regulated Price Plan Cost Suppy Report May 1, 2018 - April 30, 2019*