ATIKOKAN HYDRO INC.

117 Gorrie Street, Box 1480
Atikokan, Ontario P0T 1C0
Telephone (807)597-6600
Fax (807)597-6988
email jen.wiens@athydro.com
Website: www.athydro.com

March 22, 2017

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON. M4P 1E4

Dear Ms. Walli:

RE: EB-2016-0056 – Atikokan Hydro Inc. 2017 Rate Application
Vulnerable Energy Consumers Coalition (VECC) Interrogatory Responses

Pursuant to Procedural Order No. 1 dated February 17, 2017, in the above noted matter, please find enclosed the Atikokan Hydro Inc. ("Atikokan") interrogatory responses to the Vulnerable Energy Consumers Coalition ("VECC"). Further Atikokan has updated and submitted in live excel format through the RESS filing system the following several excel models:

- Atikokan_2017_Test_year_Income_Tax_PILS_Workform_IR1_20170322
- Atikokan_2017_Cost_Allocation_Model_IR1_20170322
- Atikokan_2017_Rev_Reqt_Work_Form_IR1_20170322
- Atikokan_2017_DVA_Continuity_Schedule_IR1_20170322
- Atikokan_2017_Tariff_Schedule_and_Bill_Impact_Model_20170322
- Atikokan_2017_LRAMVA_Work_Form_20170322

Other files also submitted as per interrogatory response:

- Atikokan_CDM_Plan_2015-2020_IR1_3-VECC-19_20170322
- Atikokan_2011-2014_CDM_Reports_Results_IR1_3-VECC-28_20170322
- Atikokan_Final_2015_Annual_Verified_Results_Report_IR1_3-VECC-19_20170322

An electronic copy of the interrogatory responses have been submitted to the Board through system and two hard copies will be delivered to the OEB office.

If you have any further questions, please do not hesitate to contact at (807)597-6600 or via email at jen.wiens@athydro.com.

Yours truly,

Original signed by

Ms. Jennifer Wiens
CEO, Secretary/Treasurer

cc: Chris Codd, Ontario Energy Board
Ian Richlier, Ontario Energy Board
Mark Garner, VECC
Bill Harper, VECC
Michael Janigan, VECC

Atikokan Hydro Inc

Vulnerable Energy Consumers Coalition (VECC)
Interrogatory Responses

EB-2016-0056

Rates Effective: May 1, 2017

Contents

1.0-VECC-1 3
1.0-VECC-2 6
2.0-VECC-3 7
2.0-VECC-4 8
2.0-VECC-5 10
2.0-VECC-6 11
2.0-VECC-7 15
2.0-VECC-8 17
2.0-VECC-9 23
2.0-VECC-10 26
2.0-VECC-11 35
2.0-VECC-12 36
2.0-VECC-13 37
2.0-VECC-14 38
2.0-VECC-15 40
3.0-VECC-16 41
3.0-VECC-17 43
3.0-VECC-18 46
3.0-VECC-19 48
3.0-VECC-20 49
4.0-VECC-21 51
4.0-VECC-22 55
4.0-VECC-23 56
4.0-VECC-24 57
4.0-VECC-25 58
4.0-VECC-26 59
4.0-VECC-27 60
4.0-VECC-28 61
4.0-VECC-29 62

5.0-VECC-30.....63
5.0-VECC-31.....64
5.0-VECC-32.....12
7.0-VECC-33.....14
7.0-VECC-34.....15
7.0-VECC-35.....16
8.0-VECC-36.....17
9.0-VECC-37.....18
9.0-VECC-38.....19

1.0 ADMINISTRATION (EXHIBIT 1)

1.0-VECC-1

Reference: E1/pg. 19

a) We are unable to locate the customer engagement survey referenced in Appendix 2-AC. Please file the survey if it has not been included in the application.

RESPONSE

a) The customer satisfaction survey referenced in Appendix 2-AC is as follows:

ATIKOKAN HYDRO INC.

Your feedback is very important to us. Please complete and return this survey to us.

Your name will be entered into our draw for $150 credit on your hydro account.

email to: info@athydro.com or by **fax at (807)597-6988** or by **mail or in person to:**

Atikokan Hydro Inc. 117 Gorrie St. PO Box 1480 Atikokan, ON P0T 1C0

Contest Closes Friday April 8, 2016. Winner will be drawn Monday April 11, 2016

Note: Only current Atikokan Hydro customers are eligible for the draw. One survey per account. Atikokan Hydro will keep all personal information confidential in accordance to the requirements of the Freedom of Information and Protection of Privacy Act. Atikokan Hydro Inc employees are ineligible to participate.

Please fill out your name, telephone number and AHI account number (7xxxxx-7xxxxx) below		Scoring Legend			***Your Score***	
Your Name:	Address:	Not Satisfied	Neither Satisfied or Dissatisfied	Satisfied	**Your Score**	Don't Know
Account Number:						
Tel. Number:						
1	Overall, how satisfied are you with the services provided by Atikokan Hydro?	1	2	3		☐
2	How satisfied are you with the reliability of the electricity supplied to you overall?	1	2	3		☐
3	How satisfied are you with how Atikokan Hydro Inc communicates **planned** outages to you?	1	2	3		☐
4	Now thinking specifically about **unplanned** outages, how satisfied are you with Atikokan Hydro:					
	a. Responding to power outages, overall?	1	2	3		☐
	b. Amount of time taken to restore power?	1	2	3		☐
	c. Ability to respond to questions?	1	2	3		☐
	d. Communication when power will be restored?	1	2	3		☐
	e. Communication why an outage occurred?	1	2	3		☐
5	Thinking of recent power outages that you have experienced:					Don't Know
	a. On average, for how many minutes do power outages last?			(<- minutes)		☐
	b. To the best of your knowledge what caused these outages?					☐
	c. What impact, if any, did these power outages have on you or your family?					☐
6	Regarding your Atikokan Hydro Inc billing, please answer the following questions	Not Satisfied	Neither Satisfied or Dissatisfied	Satisfied	**Your Score**	Don't Know
	Atikokan Hydro Inc provides accurate bills	1	2	3		☐
	Atikokan Hydro Inc provides convenient options to pay my bills	1	2	3		☐
	Atikokan Hydro Inc provides convenient options to receive my bills	1	2	3		☐
	Overall, how satisfied are you with the customer service provided by Atikokan Hydro?	1	2	3		☐
7	While Atikokan Hydro Inc is responsible for collecting payment for the entire electricity bill, only about 26% of the average residential customer's bill is retained. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.	Not Familiar	Somewhat Familiar	Familiar		Don't Know
	a. Before this survey, how familiar were you with the percent of your bill that went to Atikokan Hydro?	1	2	3		☐
		Not Reasonable	Somewhat Reasonable	Reasonable		Don't Know
8	How do you feel about the percentage of your total electricity bill that you pay to Atikokan Hydro for the services that are provided:	1	2	3		☐

ATIKOKAN HYDRO INC.

			Your Response	Don't Know
9	Atikokan Hydro currently allows our customers to access their electricity consumption data and billing information through Online Billing. Is this an expense that is of value to your needs?	(Yes/No)		☐
10	Thinking of the last 12 months			Don't Know
	a. How many times have you contacted Atikokan Hydro?		(<- times)	☐
	b. What was the reason for contacting Atikokan Hydro Inc?			☐
	c. Was your response satisfactory?	(Yes/No)		☐
11	What would you say is the most important energy or electricity-related issue facing the community of Atikokan today?			☐
12	Thinking of energy consumption and conservation:			
	a. Have you made changes to reduce your energy consumption?	(Yes/No)		☐
	b. If yes to 'a', what have you done to reduce your consumption?			☐
	c. Atikokan Hydro has Conservation Demand Management targets set by the Ontario Government directive to the Ontario Energy Board. Are you familiar with this?	(Yes/No)		☐
	d. Are you interested in learning more about Conservation Demand Management?	(Yes/No)		☐

13 Are there any specific things that Atikokan Hydro Inc could improve on to serve you better?

14 Any other general comments for Atikokan Hydro Inc?

1.0-VECC-2
Reference E1/pg.19

a) How many customers (by class) are on e-billing?
b) Are all Atikokan customers on monthly billing?
c) When did Atikokan make the move to monthly billing?

RESPONSE

a) The customers by class on e-billing are as follows:

Class	Count
Residential	257
General Service < 50	53
General Service > 50	14
Total	324

b) Yes all Atikokan customers are on a monthly billing basis.
c) Atikokan moved to monthly billing May of 2010.

2.0 RATE BASE (EXHIBIT 2)

2.0-VECC-3

Reference: E2/pg.5

a) Please update Table 2-2 for 2016 (unaudited) actuals.

RESPONSE

a) Table 2-2 has been updated for 2016 unaudited actuals as requested.

SUMMARY OF RATE BASE	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Unaudited Actual	2017 Test Year
Opening Balance Gross Fixed Assets		5,224,251	5,483,253	5,791,257	5,972,922	6,152,522	6,440,543
Ending Balance Gross Fixed Assets		5,483,329	5,791,257	5,972,922	6,152,522	6,440,543	7,042,005
Average Gross Fixed Assets	**5,438,424**	**5,353,790**	**5,637,255**	**5,882,090**	**6,062,722**	**6,296,533**	**6,741,274**
Opening Balance Accumulated Depreciation		3,043,622	3,240,222	3,400,591	3,320,273	3,449,565	3,591,214
Ending Balance Accumulated Depreciation		3,240,222	3,400,591	3,320,273	3,449,565	3,591,214	3,648,099
Average Accumulated Depreciation	**3,117,866**	**3,141,922**	**3,320,407**	**3,360,432**	**3,384,919**	**3,520,390**	**3,619,657**
Average Net Fixed Assets	**2,320,558**	**2,211,868**	**2,316,849**	**2,521,658**	**2,677,803**	**2,776,143**	**3,121,618**
Working Capital	3,192,948	3,250,989	3,460,237	3,588,396	5,052,500	5,965,640	4,957,212
Working Capital Allowance	478,942	487,648	519,036	538,259	757,875	447,423	371,791
Total Rate Base	**$2,799,500**	**$2,699,516**	**$2,835,884**	**$3,059,917**	**$3,435,678**	**$3,223,566**	**$3,493,408**

SUMMARY OF WORKING CAPITAL CALCULATION	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Unaudited Actual	2017 Test Year
Distribution Expenses - Operations	345,329	148,936	242,278	256,339	313,354	378,171	376,877
Distribution Expenses - Maintenance	41,177	150,317	170,353	153,751	131,756	93,416	120,741
Billing and Collecting	150,191	162,936	250,641	180,534	186,154	163,038	184,336
Community Relations							
Administrative and General Expenses	493,303	621,329	387,923	309,327	422,985	419,268	415,442
Taxes other than Income Taxes (Property Tax)						20,492	20,007
Total Eligible Distribution Expenses	**1,030,000**	**1,083,518**	**1,051,195**	**899,951**	**1,054,249**	**1,074,385**	**1,117,403**
Cost of Power	2,162,948	2,167,471	2,409,042	2,688,445	3,998,251	4,891,255	3,839,809
Total Expenses for Working Capital	**3,192,948**	**3,250,989**	**3,460,237**	**3,588,396**	**5,052,500**	**5,965,640**	**4,957,212**
Working Capital Factor	15%	15%	15%	15%	15%	7.5%	7.5%
Total Working Capital Allowance	**$478,942**	**$487,648**	**$519,036**	**$538,259**	**$757,875**	**$447,423**	**$371,791**

2.0-VECC-4
Reference: E2/pg.9

a) Please clarify how the variance of $99,984 as between 2012 Board approved and actuals was due to smart meter recognition. Specifically please provide the EB-2011-0293 Draft Rate Order revision (July 16, 2012) approved continuity schedule for 2012 and explain the variance as between the 2012 schedule filed at page 9.

RESPONSE

a) The approved 2012 continuity schedule is as follows:

Atikokan notes as per EB-2011-0293 Draft Rate Order board approved

- Average Gross Fixed Assets $5,438,424
- Average Accumulated Depreciation $3,117,866

		2012 Board Approved								
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	0	0	0	0	0	0	0	0	0
1806	Land Rights	0	0	0	0	0	0	0	0	0
1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	0
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Prima	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Prima	504,230	8,000	0	512,230	333,696	15,500	0	349,196	163,034
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	2,110,923	58,800	5,000	2,164,723	1,190,412	55,192	5,000	1,240,604	924,119
1835	Overhead Conductors and Devices	0	0	0	0	0	0	0	0	0
1840	Underground Conduit	0	0	0	0	0	0	0	0	0
1845	Underground Conductors and Devices	0	0	0	0	0	0	0	0	0
1850	Line Transformers	507,882	7,000	1,000	513,882	374,699	4,037	1,000	377,736	136,147
1855	Services	0	0	0	0	0	0	0	0	0
1860	Meters	422,356	0	0	422,356	54,130	16,220	0	70,350	352,005
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
1905	Land	15,588	0	0	15,588	0	0	0	0	15,588
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	685,382	0	0	685,382	286,699	24,729	0	311,428	373,954
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1915	Office Furniture and Equipment	61,120	0	0	61,120	48,109	3,132	0	51,241	9,879
1920	Computer Equipment - Hardware	49,090	12,000	2,000	59,090	45,123	1,457	2,000	44,581	14,509
1925	Computer Software	178,186	8,000	1,000	185,186	178,187	2,000	1,000	179,187	5,999
1930	Transportation Equipment	762,757	0	0	762,757	465,502	22,822	0	488,324	274,433
1935	Stores Equipment	0	0	0	0	0	0	0	0	0
1940	Tools, Shop and Garage Equipment	90,260	16,500	0	106,760	70,624	5,279	0	75,903	30,857
1945	Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	0	0	0	0	0	0	0	0	0
1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
1970	Load Management Controls - Customer Premise	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	0	0	0	0	0	0	0	0	0
2005	Property under Capital Lease	0	0	0	0	0	0	0	0	0
	Total before Work in Process	**5,387,774**	**110,300**	**9,000**	**5,489,074**	**3,047,182**	**150,368**	**9,000**	**3,188,550**	**2,300,524**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**5,387,774**	**110,300**	**9,000**	**5,489,074**	**3,047,182**	**150,368**	**9,000**	**3,188,550**	**2,300,524**

The variance between the 2012 Board approved and the 2012 actuals was mainly a result of:

- Actual opening 2012 balance was less than board approved (-163,253)
- Actual 2012 capital additions was greater than board approved; mainly smart meters and poles, towers and fixtures
- Stranded meters being reallocated to a variance account

All of the above contributing to the variance of $99,984. The variance in working capital would also contribute with differences in OM&A and Cost of Power.

2.0-VECC-5

Reference: E2/pg.19

a) Please explain why prior to 2013 "*The number of poles and structures replaced cannot be accurately quantified*;"
b) Please provide the number of poles replaced in each year 2013 through 2016 and the forecast number for 2017.

RSEPONSE

a) Prior to 2013 "the number of poles and structures replaced cannot be accurately quantified" because Atikokan Hydro did not have pole tags in place.
b) The number of poles replaced for each of the years 2013 through 2016 are as follows including the 2017 forecast quantity of pole replacements:
   2013 - 26
   2014 - 49
   2015 - 58
   2016 - 62
   2017 - 70

2.0-VECC-6
Reference: E2/pg.29

a) Please update the working capital allowance for
   i. The Board October 14, 2016 updated Regulated Price Plan Price Report – if necessary.
   ii. The October 27, 2016 Board updated cost of capital parameters (see IR 5-VECC-32 below)

RESPONSE

a) The working capital allowance as been updated for
   i. The Board October 14, 2016 updated Regulated Price Plan Price Report – if necessary.
   ii. The October 27, 2016 Board updated cost of capital parameters (see IR 5-VECC-32 below).

As a result, the updated working capital allowance is $371,791. Supporting calculation is as follows.

SUMMARY OF WORKING CAPITAL CALCULATION	2016 Unaudited Actual	2017 Test Year
Distribution Expenses - Operations	378,171	376,877
Distribution Expenses - Maintenance	93,416	120,741
Billing and Collecting	163,038	184,336
Community Relations		
Administrative and General Expenses	419,268	415,442
Taxes other than Income Taxes (Property Tax)	20,492	20,007
Total Eligible Distribution Expenses	**1,074,385**	**1,117,403**
Cost of Power	4,891,255	3,839,809
Total Expenses for Working Capital	**5,965,640**	**4,957,212**
Working Capital Factor	7.5%	7.5%
Total Working Capital Allowance	**$447,423**	**$371,791**

SUMMARY OF RATE BASE	2016 Unaudited Actual	2017 Test Year
Opening Balance Gross Fixed Assets	6,152,522	6,440,543
Ending Balance Gross Fixed Assets	6,440,543	7,042,005
Average Gross Fixed Assets	**6,296,533**	**6,741,274**
Opening Balance Accumulated Depreciation	3,449,565	3,591,214
Ending Balance Accumulated Depreciation	3,591,214	3,648,099
Average Accumulated Depreciation	**3,520,390**	**3,619,657**
Average Net Fixed Assets	**2,776,143**	**3,121,618**
Working Capital	5,965,640	4,957,212
Working Capital Allowance	447,423	371,791
Total Rate Base	**$3,223,566**	**$3,493,408**

2017 Load Foreacst	**kWh**	**kW**	**%RPP**		
Residential	9,687,147		96%		
General Service < 50 kW	5,139,223		96%		
General Service 50 to 4,999 kW	4,215,211	34,102	0%		
General Service 50 to 4,999 kW Interval	7,828,250		0%		
Street Lighting	461,749	1,430	0%		
TOTAL	**27,331,580**	**35,532**			

Electricity - Commodity RPP					
Class per Load Forecast RPP	**2012 Forecasted Metered kWhs**	**2012 Loss Factor**	**2017**		
Residential	9,299,661	1.1003	10,232,417	$0.11239	$1,150,021
General Service < 50 kW	4,933,654	1.1003	5,428,500	$0.11239	$610,109
General Service 50 to 4,999 kW	0	1.1003	0	$0.11239	$0
Street Lighting	0	1.1003	0	$0.11239	$0
TOTAL	**14,233,315**		**15,660,917**		**$1,760,130**

Electricity - Commodity Non-RPP					
Class per Load Forecast	**2012 Forecasted Metered kWhs**	**2012 Loss Factor**	**2017**		
Residential	387,486	1.1003	426,351	$0.10709	$45,658
General Service < 50 kW	205,569	1.1003	226,187	$0.10709	$24,222
General Service 50 to 4,999 kW	4,215,211	1.1003	4,637,997	$0.10709	$496,683
General Service 50 to 4,999 kW Interval	7,828,250	1.1013	8,621,251	$0.10709	$923,250
Street Lighting	461,749	1.1003	508,062	$0.10709	$54,408
TOTAL	**13,098,265**		**14,419,849**		**$1,544,222**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**	**2017**		
Residential		kWh	10,658,768	$0.0064	$68,216
General Service < 50 kW		kWh	5,654,687	$0.0057	$32,232
General Service 50 to 4,999 kW		kW	11,936	$2.3017	$27,472
General Service 50 to 4,999 kW Interval		kW	22,166	$2.4419	$54,128
Street Lighting		kW	1,430	$1.7360	$2,482
TOTAL					**$184,531**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**	**2017**		
Residential		kWh	10,658,768	$0.0040	$42,635
General Service < 50 kW		kWh	5,654,687	$0.0034	$19,226
General Service 50 to 4,999 kW		kW	11,936	$1.3767	$16,432
General Service 50 to 4,999 kW Interval		kW	22,166	$1.5216	$33,728
Street Lighting		kW	1,430	$1.0641	$1,522
TOTAL					**$131,048**

Wholesale Market Service					
Class per Load Forecast				**2017**	
Residential			10,658,768	$0.0036	$38,372
General Service < 50 kW			5,654,687	$0.0036	$20,357
General Service 50 to 4,999 kW			4,637,997	$0.0036	$16,697
General Service 50 to 4,999 kW Interval			8,621,251	$0.0036	$31,037
Street Lighting			508,062	$0.0036	$1,829
TOTAL			**30,080,766**		**$108,291**

Rural Rate Assistance					
Class per Load Forecast				**2017**	
Residential			10,658,768	$0.0021	$22,383
General Service < 50 kW			5,654,687	$0.0021	$11,875
General Service 50 to 4,999 kW			4,637,997	$0.0021	$9,740
General Service 50 to 4,999 kW Interval			8,621,251	$0.0021	$18,105
Street Lighting			508,062	$0.0021	$1,067
TOTAL			**30,080,766**		**$63,170**

Ontario Electricity Support Program					
Class per Load Forecast				**2017**	
Residential			10,658,768	$0.0011	$11,725
General Service < 50 kW			5,654,687	$0.0011	$6,220
General Service 50 to 4,999 kW			4,637,997	$0.0011	$5,102
General Service 50 to 4,999 kW Interval			8,621,251	$0.0011	$9,483
Street Lighting			508,062	$0.0011	$559
TOTAL			**30,080,766**		**$33,089**

Smart Meter Entity Charge					
Class per Load Forecast				**2017**	
Residential			1,389	$0.7900	$13,168
General Service < 50 kW			228	$0.7900	$2,161
General Service 50 to 4,999 kW			n/a		
General Service 50 to 4,999 kW Interval					
Street Lighting			n/a		
TOTAL			**1,617**		**$15,329**

Cost of Power Account	**2017**
4705-Power Purchased	$3,304,352
4708-Charges-WMS	$108,291
4714-Charges-NW	$184,531
4716-Charges-CN	$131,048
4730-Rural Rate Assistance	$63,170
Ontario Electricity Support Program	$33,089
Smart Meter Entity Charge	$15,329
4750-Low Voltage	
TOTAL	**3,839,809**

2.0-VECC-7

Reference: E2/pg.36 Attachment DSP/pg. 15

a) Please update Table 2-18 (Service Reliability) to include 2016 results.
b) Please explain the spike in outages and outage duration (excluding loss of supply) in 2013.
c) Please revise Table 2-5 (outage causes) to include 2016 results.

RESPONSE

a) Table 2-18 Service Reliability is updated to include 2016 results. Please note these are unverified results. The 2016 reliability statistics have not been finalized for OEB RRR Reporting.

Index	Including outages caused by loss of supply						Excluding outages caused by loss of supply					
	2011	2012	2013	2014	2015	2016	2011	2012	2013	2014	2015	2016
SAIDI	0.780	4.310	3.430	0.370	4.150	0.035	0.020	0.300	3.430	0.370	0.130	0.032
SAIFI	0.360	1.470	1.120	0.090	1.040	1.303	0.150	0.470	1.120	0.090	0.030	0.294

Excluding Major Event Days					
2011	2012	2013	2014	2015	2016
0.000	0.000	0.000	0.000	0.000	0.000
0.000	0.000	0.000	0.000	0.000	0.000

6 Year Historical Average								
SAIDI		2.608			0.850			0.000
SAIFI		0.816			0.372			0.000
Including outages caused by loss of supply			Excluding outages caused by loss of supply			Excluding Major Event Days		

b) The spike in outages and outage duration (excluding loss of supply) in 2013 is a result of scheduled (planned) outages. These outages are required for the safety of both employees and the general public in instances such as transferring of services from old poles to new poles or relocating and or replacing a transformer. It should be noted these planned outages rarely are town wide and typically affect only a few residential streets at a time.
c) As requested Table 2-5 (Outage Causes) has been updated to include 2016 results

Most Frequent Outage Cause						
	Year					
Cause of Fault	2012	2013	2014	2015	2016	Total
Unknown	0	0	1	1	1	3
Scheduled	2	9	8	0	16	35
Supply Loss	0	0	0	1	1	2
Tree Contact	3	0	0	1	2	6
Lightning	0	2	1	0	0	3
Defective Equipment	3	0	1	1	4	9
Weather	5	6	0	2	0	13
Enviroment Code	1	0	0	0	0	1
Human Element	2	3	2	4	1	12
Foreign Interface	2	1	0	0	0	3
Total	18	21	13	10	25	

2.0-VECC-8

Reference: E2/pg. 38

a) Please update Appendix 2-AB to include:
   i. 2016 results;
   ii. 2012 Board approved
   iii. The budget amounts for years 2013 through 2016.

RESPONSE

a) Appendix 2-AB is updated to include:
   i. 2016 results;
   ii. 2012 Board approved
   iii. The budget amounts for years 2013 through 2016.

Accounting Standard MIFRS
Year **2016** **Unaudited**

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 42,959			$ 42,959	-$ 32,337	-$ 6,480		-$ 38,817	$ 4,142
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ -			$ -	$ -			$ -	$ -
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 502,785	$ 13,805	-$ 7,322	$ 509,268	-$ 383,190	-$ 12,553	$ 6,006	-$ 389,736	$ 119,531
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	**$ 2,844,263**	**$ 343,054**	**-$ 43,480**	**$ 3,143,837**	-$ 1,391,668	-$ 73,134	$ 25,012	-$ 1,439,790	$ 1,704,047
47	1835	Overhead Conductors & Devices	$ -			$ -	$ -			$ -	$ -
47	1840	Underground Conduit	$ -			$ -	$ -			$ -	$ -
47	1845	Underground Conductors & Devices	$ -			$ -	$ -			$ -	$ -
47	1850	Line Transformers	$ 460,475		-$ 13,833	$ 446,642	-$ 336,664	-$ 5,635	$ 13,494	-$ 328,805	$ 117,836
47	1855	Services (Overhead & Underground)	$ -			$ -	$ -			$ -	$ -
47	1860	Meters	$ 177,518		-$ 8,986	$ 168,532	-$ 71,672	-$ 6,893		-$ 78,565	$ 89,967
47	1860	Meters (Smart Meters)	$ 476,884			$ 476,884	-$ 153,660	-$ 36,680	$ 3,235	-$ 187,105	$ 289,779
N/A	1905	Land	$ 15,588			$ 15,588	$ -			$ -	$ 15,588
47	1908	Buildings & Fixtures	$ 683,677			$ 683,677	-$ 386,053	-$ 11,197		-$ 397,250	$ 286,427
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 40,034			$ 40,034	-$ 35,956			-$ 35,956	$ 4,078
8	1915	Office Furniture & Equipment (5 years)	$ 22,685			$ 22,685	-$ 20,664	-$ 2,269		-$ 22,933	-$ 248
10	1920	Computer Equipment - Hardware	$ -	$ 1,435		$ 1,435	$ -			$ -	$ 1,435
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 90			$ 90	-$ 90			-$ 90	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 28,436			$ 28,436	-$ 14,083	-$ 4,926		-$ 19,009	$ 9,427
10	1930	Transportation Equipment	$ 754,182			$ 754,182	-$ 536,909	-$ 24,365		-$ 561,274	$ 192,908
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 123,069	$ 3,349		$ 126,418	-$ 87,076	-$ 5,722		-$ 92,798	$ 33,620
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 20,123			-$ 20,123	$ 457	$ 457		$ 914	-$ 19,209
			$ -			$ -				$ -	$ -
		Sub-Total	**$ 6,152,522**	**$ 361,642**	**-$ 73,621**	**$ 6,440,543**	**-$ 3,449,565**	**-$ 189,397**	**$ 47,748**	**-$ 3,591,214**	**$ 2,849,329**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 6,152,522**	**$ 361,642**	**-$ 73,621**	**$ 6,440,543**	**-$ 3,449,565**	**-$ 189,397**	**$ 47,748**	**-$ 3,591,214**	**$ 2,849,329**

		2012 Board Approved								
OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
1805	Land	0	0	0	0	0	0	0	0	0
1806	Land Rights	0	0	0	0	0	0	0	0	0
1808	Buildings and Fixtures	0	0	0	0	0	0	0	0	0
1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Prima	0	0	0	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Prima	504,230	8,000	0	512,230	333,696	15,500	0	349,196	163,034
1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	2,110,923	58,800	5,000	2,164,723	1,190,412	55,192	5,000	1,240,604	924,119
1835	Overhead Conductors and Devices	0	0	0	0	0	0	0	0	0
1840	Underground Conduit	0	0	0	0	0	0	0	0	0
1845	Underground Conductors and Devices	0	0	0	0	0	0	0	0	0
1850	Line Transformers	507,882	7,000	1,000	513,882	374,699	4,037	1,000	377,736	136,147
1855	Services	0	0	0	0	0	0	0	0	0
1860	Meters	422,356	0	0	422,356	54,130	16,220	0	70,350	352,005
1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
1905	Land	15,588	0	0	15,588	0	0	0	0	15,588
1906	Land Rights	0	0	0	0	0	0	0	0	0
1908	Buildings and Fixtures	685,382	0	0	685,382	286,699	24,729	0	311,428	373,954
1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
1915	Office Furniture and Equipment	61,120	0	0	61,120	48,109	3,132	0	51,241	9,879
1920	Computer Equipment - Hardware	49,090	12,000	2,000	59,090	45,123	1,457	2,000	44,581	14,509
1925	Computer Software	178,186	8,000	1,000	185,186	178,187	2,000	1,000	179,187	5,999
1930	Transportation Equipment	762,757	0	0	762,757	465,502	22,822	0	488,324	274,433
1935	Stores Equipment	0	0	0	0	0	0	0	0	0
1940	Tools, Shop and Garage Equipment	90,260	16,500	0	106,760	70,624	5,279	0	75,903	30,857
1945	Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
1955	Communication Equipment	0	0	0	0	0	0	0	0	0
1960	Miscellaneous Equipment	0	0	0	0	0	0	0	0	0
1970	Load Management Controls - Customer Premise	0	0	0	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	0	0	0	0	0	0	0	0	0
1980	System Supervisory Equipment	0	0	0	0	0	0	0	0	0
1985	Sentinel Lighting Rentals	0	0	0	0	0	0	0	0	0
1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
1995	Contributions and Grants	0	0	0	0	0	0	0	0	0
2005	Property under Capital Lease	0	0	0	0	0	0	0	0	0
	Total before Work in Process	**5,387,774**	**110,300**	**9,000**	**5,489,074**	**3,047,182**	**150,368**	**9,000**	**3,188,550**	**2,300,524**
	Work in Process	0			0	0			0	0
	Total after Work in Process	**5,387,774**	**110,300**	**9,000**	**5,489,074**	**3,047,182**	**150,368**	**9,000**	**3,188,550**	**2,300,524**

2013 Fixed Assets Budget

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land				$ -				$ -	$ -
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV				$ -				$ -	$ -
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 109,380		$ -				$ -	$ -
47	1835	Overhead Conductors & Devices				$ -				$ -	$ -
47	1840	Underground Conduit				$ -				$ -	$ -
47	1845	Underground Conductors & Devices				$ -				$ -	$ -
47	1850	Line Transformers				$ -				$ -	$ -
47	1855	Services (Overhead & Underground)				$ -				$ -	$ -
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware		$ 7,500		$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment				$ -				$ -	$ -
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment				$ -				$ -	$ -
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment				$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]				$ -				$ -	$ -
										$ -	$ -
		Sub-Total	**$ -**	**$ 116,880**	**$ -**	**$ -**	**$ -**	**-$163,052**	**$ -**	**$ -**	**-$ 46,172**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ -**	**$ 116,880**	**$ -**	**$ -**	**$ -**	**-$163,052**	**$ -**	**$ -**	**-$ 46,172**

2014 Fixed Assets Budget

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land				$ -				$ -	$ -
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 8,760		$ -				$ -	$ -
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 104,280		$ -				$ -	$ -
47	1835	Overhead Conductors & Devices				$ -				$ -	$ -
47	1840	Underground Conduit				$ -				$ -	$ -
47	1845	Underground Conductors & Devices				$ -				$ -	$ -
47	1850	Line Transformers		$ 35,000		$ -				$ -	$ -
47	1855	Services (Overhead & Underground)				$ -				$ -	$ -
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment				$ -				$ -	$ -
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 16,400		$ -				$ -	$ -
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment				$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]				$ -				$ -	$ -
										$ -	$ -
		Sub-Total	**$ -**	**$ 164,440**	**$ -**	**$ -**	**$ -**	**-$163,053**	**$ -**	**$ -**	**$ 1,387**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ -**	**$ 164,440**	**$ -**	**$ -**	**$ -**	**-$163,053**	**$ -**	**$ -**	**$ 1,387**

2015 Fixed Assets Budget

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land				$ -				$ -	$ -
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 8,760		$ -				$ -	$ -
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 96,820		$ -				$ -	$ -
47	1835	Overhead Conductors & Devices				$ -				$ -	$ -
47	1840	Underground Conduit				$ -				$ -	$ -
47	1845	Underground Conductors & Devices				$ -				$ -	$ -
47	1850	Line Transformers		$ 7,000		$ -				$ -	$ -
47	1855	Services (Overhead & Underground)				$ -				$ -	$ -
47	1860	Meters		$ 22,000		$ -				$ -	$ -
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment		$ 8,500		$ -				$ -	$ -
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 8,000		$ -				$ -	$ -
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment				$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets		$ 25,000		$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]				$ -				$ -	$ -
										$ -	$ -
		Sub-Total	**$ -**	**$ 176,080**	**$ -**	**$ -**	**$ -**	**-$173,088**	**$ -**	**$ -**	**$ 2,992**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ -**	**$ 176,080**	**$ -**	**$ -**	**$ -**	**-$173,088**	**$ -**	**$ -**	**$ 2,992**

2016 Fixed Assets Budget

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land				$ -				$ -	$ -
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 11,106		$ -				$ -	$ -
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 186,618		$ -				$ -	$ -
47	1835	Overhead Conductors & Devices				$ -				$ -	$ -
47	1840	Underground Conduit				$ -				$ -	$ -
47	1845	Underground Conductors & Devices				$ -				$ -	$ -
47	1850	Line Transformers				$ -				$ -	$ -
47	1855	Services (Overhead & Underground)				$ -				$ -	$ -
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment				$ -				$ -	$ -
8	1935	Stores Equipment				$ -				$ -	$ -
8	1940	Tools, Shop & Garage Equipment		$ 8,500		$ -				$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -				$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -				$ -	$ -
8	1955	Communications Equipment	$ -			$ -				$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -			$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ 20,000		$ -				$ -	$ -
47	1990	Other Tangible Property	$ -			$ -				$ -	$ -
47	1995	Contributions & Grants	$ -			$ -				$ -	$ -
47	2440	Deferred Revenue[5]								$ -	$ -
										$ -	$ -
		Sub-Total	**$ -**	**$ 226,224**	**$ -**	**$ -**	**$ -**	**-$196,885**	**$ -**	**$ -**	**$ 29,339**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ -**	**$ 226,224**	**$ -**	**$ -**	**$ -**	**-$196,885**	**$ -**	**$ -**	**$ 29,339**

2.0-VECC-9

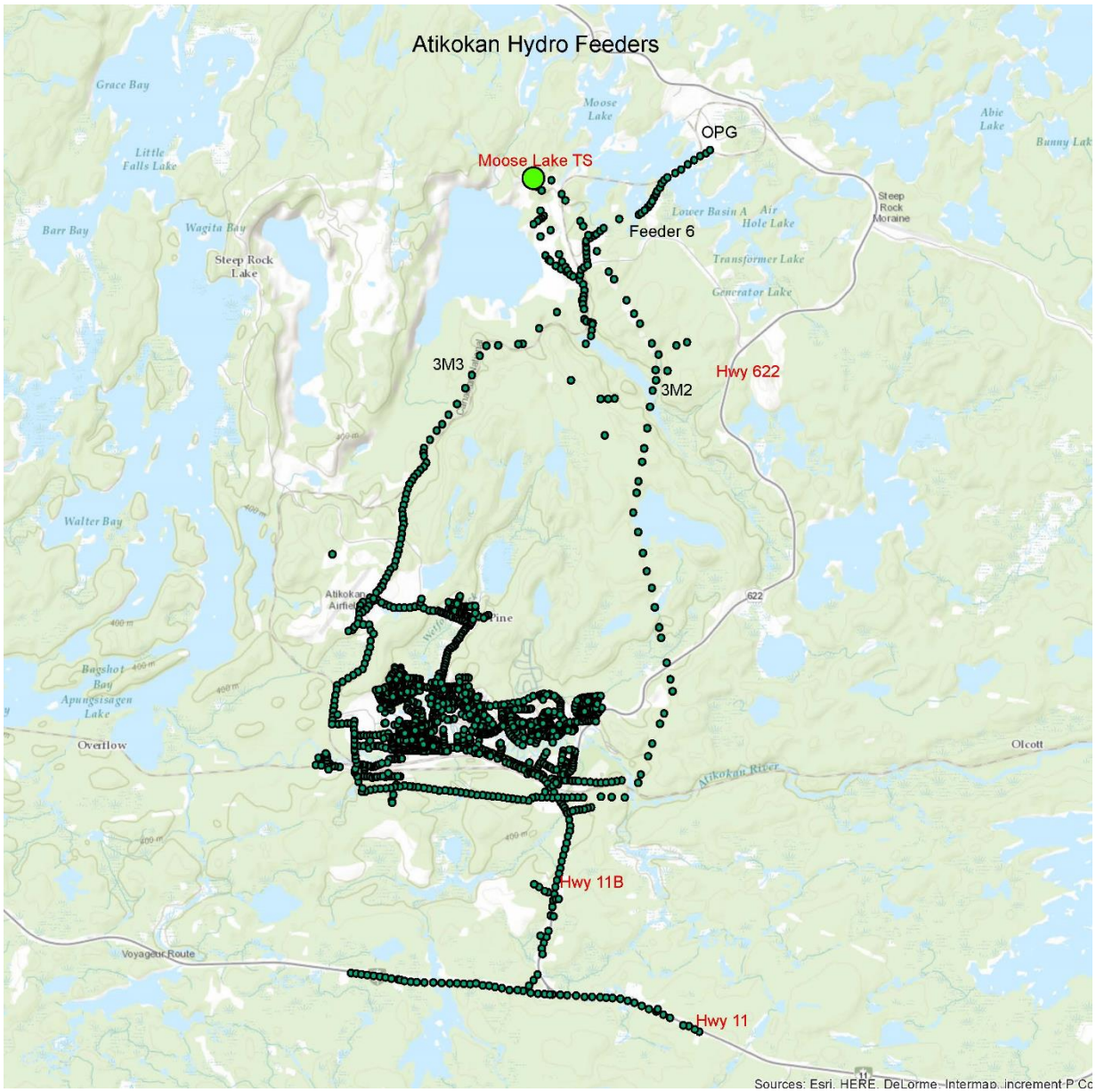
Reference: E2/Attachment DSP

a) Was Atikokan's DSP developed internally? If not please provide the name of the firm/consultant who developed the plan.
b) Has the DSP been reviewed by a third party?
c) Please show the Moose Lake transformer station in relation to the major feeders of Atikokan and surrounding highways.
d) Please identify the location of the one LTLT customers and explain why the assets involved cannot be transferred/purchased by either Atikokan or Hydro One.

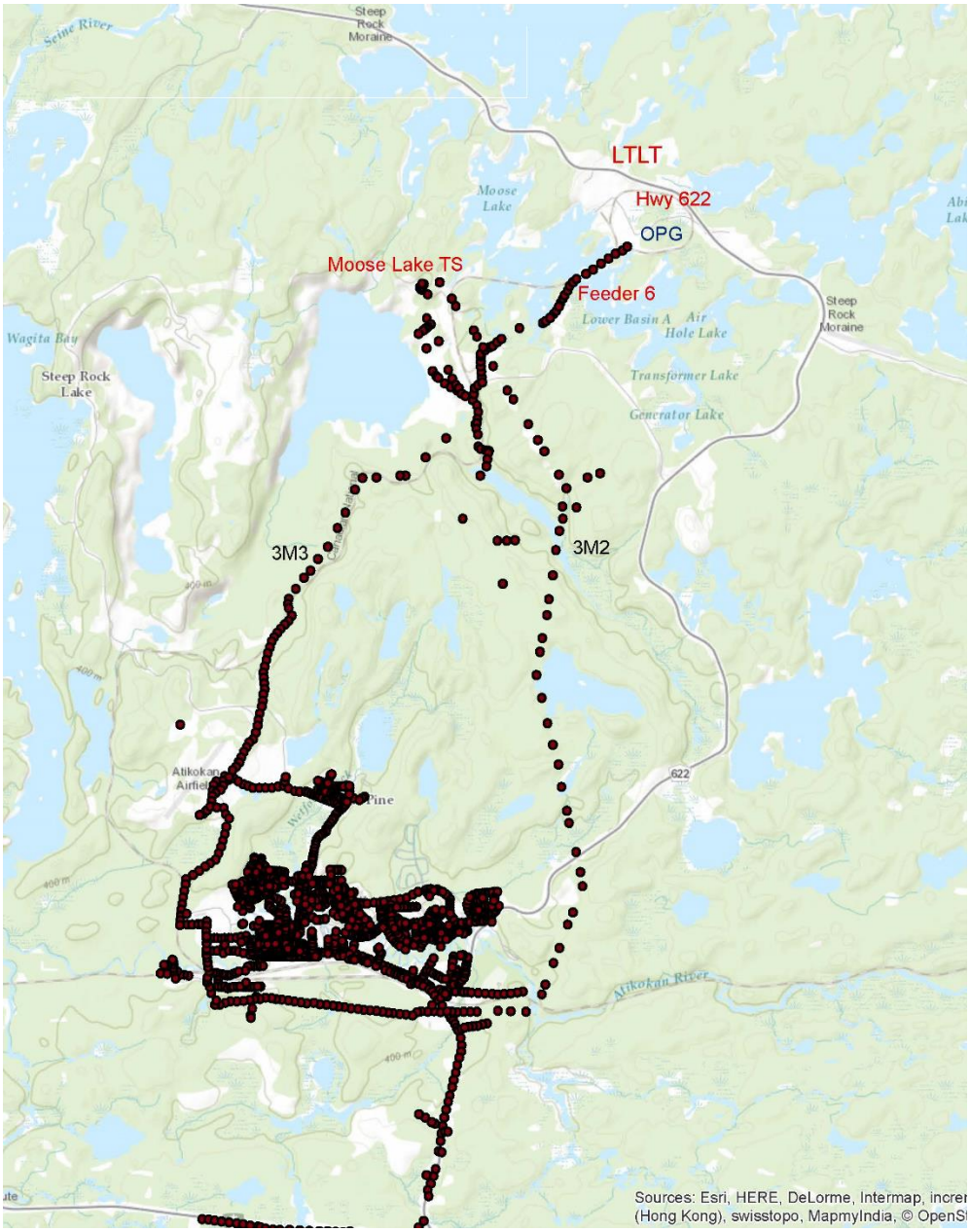
RESPONSE

a) Atikokan's DSP was developed internally.
b) The DSP has not been reviewed by a third party.

c) The following map depicts the relation of the Moose Lake transformer station (Moose Lake TS) in relation to the major feeders of Atikokan and surrounding highways.



d) The location of the LTLT customer is outside of town limits. As the following map depicts; the LTLT is just off of Highway 622 and is an approximate driving distance of 15 KM from Atikokan.



2.0-VECC-10

Reference: E2/Attachment DSP/pg. 23

a) Please update the Scorecard to include 2015 and 2016 actual results.

RESPONSE

a) Atikokan's 2015 Scorecard and Management and Discussion Analysis is on the following pages. The 2016 Scorecard is not posted until late 2017 as per the OEB guidelines. As such Atikokan does not have the 2016 Scorecard available at this time.

Scorecard - Atikokan Hydro Inc.

9/29/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target Industry	Target Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time			100.00%			100.00%	⇒	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%	⇒	90.00%	
		Telephone Calls Answered On Time		100.00%	100.00%	100.00%	100.00%	100.00%	⇒	65.00%	
	Customer Satisfaction	First Contact Resolution					95%	100			
		Billing Accuracy					100.00%	99.98%	⇩	98.00%	
		Customer Satisfaction Survey Results					Favourable	Favorable			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness						82.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	NI	C	C	⇒		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	⇒		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	⇒		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.02	0.30	3.43	0.37	0.13	⇧		0.83
		Average Number of Times that Power to a Customer is Interrupted [2]		0.15	0.47	1.12	0.09	0.03	⇒		0.37
	Asset Management	Distribution System Plan Implementation Progress					On Track	on Target			
	Cost Control	Efficiency Assessment			4	4	4	3			
		Total Cost per Customer [3]		$854	$1,057	$908	$800	$936			
		Total Cost per Km of Line [3]		$15,418	$19,069	$16,430	$14,459	$16,810			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]						9.63%			1.14 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time									
		New Micro-embedded Generation Facilities Connected On Time								90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.36	1.15	1.39	1.35	1.41			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		3.01	4.93	0.38	0.32	0.25			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.57%	9.12%	9.12%	9.12%	9.12%			
			Achieved	-5.31%	-2.52%	11.28%	28.33%	13.14%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

Legend:
6-year trend: ⇧ up ⇩ down ⇒ flat
Current year: target met; target not met

2015 Scorecard Management Discussion and Analysis ("2015 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2015 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

- In 2015, Atikokan Hydro ("Atikokan") mainly performed well in all areas of the scorecard.
- Atikokan Hydro met or exceeded all performance objectives with the exception of its deemed Return on Equity. Atikokan Hydro continues to strive to meet or exceed its scorecard performance and maintain reliability of supply to its customers with minimal interruptions.
- Atikokan understands Atikokan Hydro customers are primarily concerned with the cost of power and their total electricity bill and reliability as feedback from those who participated in Atikokan Hydro's in house customer satisfaction survey. Atikokan strives to minimize the cost per customer impacts. Similar to other LDC's, aging infrastructure and a decline in customer count continues to be a challenge for the utility but must be maintained for safety and reliable supply of electricity to those serviced by Atikokan Hydro.
- Atikokan Hydro continues to participate and offer CDM programs to its customers in efforts to not only meet its set targeted kWh Conservation Demand Management savings but for customers to reduce the amount of power consumed in order to save on their electricity bill.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  Utility's must 90% of the time connect new services for customers within five working days once all conditions of service are met; Atikokan Hydro performs connections 100% of the time on time. This exceeds the Industry target. Atikokan Hydro takes pride in its ability to honor customer requests for connections. Due to the small size of the LDC, office staff directly engage

with the outside crew and are aware of their schedules and abilities to complete work order requests. Historically Atikokan Hydro does not have a lot of new connection requests but performs the same service quality for all connection requests including disconnect/reconnects for electrical upgrades, or seasonal reconnections.

- **Scheduled Appointments Met On Time**
  Atikokan Hydro meets 100% of its scheduled appointments on time. This exceeds the Industry target of 90% Atikokan Hydro strongly believes that our customer's time is very important and should be respected by meeting all scheduled appointments on time.

- **Telephone Calls Answered On Time**
  The Ontario Energy Boards target for answering telephone calls on time is 65%; however, Atikokan Hydro exceeds this with answering 100% of calls on time and has historically been consistent. These statistics are manually logged. Atikokan Hydro has two incoming telephone lines and typically three staff are in the office to ensure incoming calls are answered in a targeted manner. Again this demonstrates Atikokan Hydro's focus on customers and excelling in service quality.

Customer Satisfaction

- **First Contact Resolution**
  First Contact Resolution is a measure of a distributor's effectiveness at satisfactory addressing customer's complaints. This measure was added in 2014; the OEB has permitted distributors discretion on how this measure is reported. Based on the 2015 Scorecard Atikokan Hydro resolves 100% of customer contact first time and does not require referral to management for resolution.

- **Billing Accuracy**
  The OEB Industry target for billing accuracy is 98%; Atikokan exceeds this with 99.98% billing accuracy for 2015. Atikokan has internal controls in place for verification of bills prior to releasing the bills to its customers.

- **Customer Satisfaction Survey Results**
  Atikokan Hydro has had a portion of the bill dedicated to customer to have the ability to express their satisfaction or

dissatisfaction with Atikokan Hydro or make comments. Atikokan Hydro did not had customers respond to this feature during 2015 and for this reason has interpreted this as favorable. Atikokan Hydro participated in its first customer satisfaction survey early in 2016. Overall of the customers that participated, results showed 97% satisfied with the services provided by Atikokan Hydro. Atikokan was pleased with the results.

Safety

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**
    The Public Awareness of Electrical Safety component of the public safety measure is expected to measure the level of awareness of key electrical safety precautions among public within the electricity distributor's service territory. It measures the degree of effectiveness for distributors' activities on preventing electrical accidents. Distributors are expected to demonstrate the impact of their public education efforts through biannual surveying of adults residing in their territory. Atikokan Hydro hired UtilityPulse to conduct a survey to determine Atikokan Hydro's Public safety Awareness. The survey was performed quarter 1 of 2016; the telephone survey results indicated an index score of 82%. Atikokan Hydro is pleased with the level of knowledge and awareness of the public on electrical safety.

  - **Component B – Compliance with Ontario Regulation 22/04**
    Atikokan Hydro takes compliance issues with the Ontario Regulation 22/04 very seriously and strives to ensure that all aspects of Regulation 22/04 are met. Any needs improvement notations from the annual audit are implemented as soon as possible. The regulation establishes safety requirements and objectives for design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Atikokan Hydro was compliant with the Ontario Regulation 22/04 for 2015 and the historical years 2010 through 2014 with the exception of 2013 with a needs improvement.

  - **Component C – Serious Electrical Incident Index**
    Atikokan Hydro is pleased to report zero serious electrical incidents and as the 2015 Scorecard indicates for the years prior to this as well. Atikokan Hydro believes safety of both staff and the public to be of the highest importance. The results received from the ESA for 2015 Scorecard reporting and historical years are as follows

Results					Target
Year	Number of Incidents	km of Line	Rate Default Value	Serious Incident Index	Serious Incident Index
2015	0	92	10	0.000	0.000
2014	0	92	10	0.000	0.000
2013	0	92	10	0.000	0.000
2012	0	92	10	0.000	0.000
2011	0	92	10	0.000	0.000
2010	0	92	10	0.000	0.000

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**
  The average hours that power is interrupted is a measure of system reliability.
  It is determined by dividing the total monthly duration of all interruptions experienced by all customers (excluding interruptions caused by Loss of Supply events), in hours, by the average number of customers served.
  The measure for 2015 is 0.13 and is considerably well compared to the last two years measure reported. Similarly to 2014, Atikokan Hydro experienced a decrease in the average number of hours that power to a customer was interrupted during 2015 as a result of fewer customers being impacted by scheduled outages as well as fewer weather related event outages. Atikokan Hydro is continually performing capital upgrades and maintenance on is distribution infrastructure to improve and maintain reliability to its customers. Atikokan Hydro's distributor target by the OEB is 0.83. The lower the reliability figure, the better the utility has performed compared to the target.

- **Average Number of Times that Power to a Customer is Interrupted**
  The average number of times that power to a customer is interrupted is a system reliability measure. It is determined by dividing the total number of interruptions experienced by all customers (excluding interruptions caused by Loss of Supply events), by the average number of customers served. The measure for 2015 is calculated as 0.03. This is the lowest it has been since 2010; reporting the same index measure of 0.03.

Asset Management

- **Distribution System Plan Implementation Progress**
  Atikokan Hydro Inc. is submitting its Distribution System Plan with its 2017 Cost of Service Rate Application. This Distribution System Plan is for the period of 2017 through 2021.

Cost Control

- **Efficiency Assessment**
  The total cost and efficiency ranking was developed by Pacific Energy Group (PEG), an independent third party consultant of the OEB. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In 2015Atikokan Hydro was placed in Group 3, where a Group 3 distributor is defined as having actual costs within +/- 10 percent of predicted costs. Group 3 is considered "average efficiency" - - in other words Atikokan Hydro's costs are within the average cost range for distributors in the Province of Ontario. This 2015 grouping in group 3 is an improvement for Atikokan Hydro from the prior year 2014 whereby Atikokan fell within Group 4 with actual costs 10-25% of predicted costs. Atikokan Hydro is continually striving to become more efficient.

- **Total Cost per Customer**
  Atikokan Hydro's total cost per customer for 2015 is $935.58. This is calculated by the sum of Atikokan Hydro's capital and operating costs divided by the total number of Atikokan Hydro's customers. Atikokan reported a total of 1653 customers for 2015. The total cost per customer has increased from the prior year 2014; while total costs have increased, Atikokan total customer base has a trend of decline year over year. An increased customer base would lower the total cost per customer. Atikokan has been heavily investing in its aging infrastructures which drives up the cost per customer. The expenditures are necessary to ensure safe and reliable supply of electricity.

- **Total Cost per Km of Line**
  Atikokan Hydro's total cost per Km of Line for 2015 is $16,809.99. This measure is calculated as the sum of capital and operating costs divided by the number of kilometers of line the utility operates to serve its customers. Atikokan has a total of

92 Km of line. Some of Atikokan Hydro's lines are in rugged and thick bush terrain with minimal access points. As a result of the challenging area, greater costs to maintain these lines are incurred.

Conservation & Demand Management

- **Net Cumulative Energy Savings**
  Atikokan Hydro in collaboration with the Northwest Group (Thunder Bay Hydro Electricity Distribution, Fort Frances Power Corp., Kenora Hydro and Sioux Lookout Hydro) received approval for its joint 2015-2020 Conservation plan. Atikokan Hydro's allocated target is 1,140,000 kWh. 2015 Final Verified Results report Atikokan Hydro has met 9.63% or 109,769 kWh of its target. Atikokan Hydro will continue all efforts and resources in offering Conservation & Demand Management (CDM) programs in efforts to achieve its CDM target. Atikokan Hydro did not meet its target for the 2011-2014 CDM framework due to various barriers but optimistic Atikokan Hydro will meet the new target with some measures in place addressing these previous framework barriers including collaborating in hiring an Regional Energy Manager with the Northwest Group in efforts to meet the targets.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**
  Atikokan Hydro did not have any renewable generation impact assessments to consider.

- **New Micro-embedded Generation Facilities Connected On Time**
  Atikokan did not have any new Micro-embedded Generation Facilities connected during 2015; however, based on previous connections and Atikokan Hydro's practices, all connection requests are completed within the prescribed time frame of five business days.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**
  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being

"liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.
Atikokan Hydro's Current Ratio was 1.41 for year ending December 31, 2015.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**
  The OEB uses a deemed capital structure of 60% debt and 40% equity or a ratio of 1.5 (60/40) for rate setting purposes. A high debt to equity ratio indicates a distributor may have difficulty generating cash flows to make its debt payments. Atikokan Hydro has significantly improved its debt to equity ratio over the last few years; continuing to pay back its borrowed debt but further converting its debt with its Shareholder, to equity. For 2015, Atikokan Hydro's debt to equity was 25% debt and 75% equity. In the past Atikokan has had to borrow for implementation of smart meters and funding capital upgrades to the distribution system.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  Atikokan Hydro's current distribution rates were approved by the Ontario Energy Board and include an expected (deemed) Regulatory Return on Equity of 9.12%. The deemed Return on Equity was approved in Atikokan Hydro's last cost of service rate application for 2012 rates in decision EB- 2011-0293. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

Atikokan Hydro's actual achieved Return on Equity for 2015 was 13.14%; thereby, slightly greater than the allowable 3% dead band.
The main driver in the over earnings above the deemed and allowable return on equity was greater distribution revenue than the Board approved distribution revenue in Atikokan Hydro's last Cost of Service Rate Application. The increased distribution revenue is a result of greater consumption and demand than the Board Approved consumption load forecast. Overall Atikokan Hydro's customer count has declined but an addition of general service customer since 2012 has contributed to this impact. A change in general service customers often have a greater material affect than a change in residential services.

2.0-VECC-11
Reference: E2/Attachment DSP/pg. 32

a) Please explain what steps were taken in the “complete 360” and which has led to the resumed profitability at Atikokan.

RESPONSE

a) Atikokan took measures to resume to profitability including the following:
- Delay in fulfilling a vacant position as a result of a retiree
- Hired an apprentice and received wage subsidy
- Converting debt to equity, substantially lowered interest payments
- Switching insurance carrier
- Large customer started production
- Smart meter approved rate riders contributed to added revenue.

2.0-VECC-12

Reference: E2/Attachment DSP/pg.44

a) If an asset health index is available please provide a table showing, by asset category (poles, transformer etc.), the total asset population and the percentage of assets in good, fair or poor condition (or whatever asset condition characterization is used by Atikokan).

RESPONSE

a) Atikokan does not have an asset health index per se for all assets but has included the information it has in its Distribution System Plan. The list on page 44 of the DSP is a summary of the data collected where possible. This will continue to evolve. Atikokan has updated the table provided on page 72 of the DSP to include the percentages of the pole conditions

Condition Legend					
1 - Very Good Condition					
2 - Good					
3 - Average					
4 - Concern					
5 - Immediate Concern	**Pole Condition**				
	1	**2**	**3**	**4**	**5**
Total	134	250	691	237	15
Total Poles per Pole Condition as a Percentage	10%	19%	52%	18%	1%

2.0-VECC-13

Reference: E2/Attachment DSP & E4/pg.16

a) Please provide the presentation of the annual budget OM&A that was approved by the Board of Directors.

RESPONSE

a) Page 16 of Exhibit 4, Atikokan was portraying the OM&A budgeting process. However, the 2016 annual budget approved by the Board of Directors is as follows:

EXPENSES		
OM&A Expenses		
	Admin	485,669
	Operations	356,607
	Maintenance	119,078
	Billing & Collecting	178,483
Total OM&A		1,139,837

2.0-VECC-14

Reference: E2/Attachment DSP/pg. 103

a) Please compare the table below taken from Atikokan's last cost of service filing and comment on its comparison to the table shown at 5.4.5.1. Specifically address:
   i. Why the major fleet purchases were not made in 2015 and 2016.
   ii. The significant increase in capital expenditures over the budgets proposed in the 2012 cost of service application – especially the major increase in 2014 as compared to all other years (net of meters)

Table 2-21 Six Year Capital Budget (EB2011-0293) E2/T2/S3/pg.1)

Asset Category	USofA	Budget 2012	Budget 2013	Budget 2014	Budget 2015	Budget 2016	Budget 2017
Transformer Station Equip >50 kV	1820	$8,000	$8,000	$35,000	$35,000	$1,000	$1,000
Poles, Towers & Fixtures	1830	$58,800	$55,000	$45,000	$30,000	$45,000	$85,000
O/H Conductors & Devices	1835	$0	$9,880	$6,000	$0	$6,000	$6,000
Line Transformers	1850	$7,000	$3,000	$3,000	$0	$0	$3,000
Services	1855	$0	$14,000	$0	$0	$0	$0
Meters	1860	$0	$2,500	$3,000	$0	$0	$2,500
Buildings and Fixtures	1908	$8,500	$4,000	$4,000	$1,000	$1,000	$1,000
Office Furniture and Equipment	1915	$0	$3,200	$1,000	$1,000	$1,000	$1,000
Computer Equipment - Hardware	1920	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000
Computer Equipment - Software	1925	$8,000	$0	$1,000	$0	$0	$0
Fleet	1930	0	$0	$-	$50,000	$325,000	$0
Tools, Shop & Garage Eq	1940	$16,500	$5,000	$1,000	$1,000	$1,000	$1,000
Measure & Test Equip	1945	$0	$2,000	$2,000	$2,000	$2,000	$2,000
Miscellaneous Equipment	1960	$0	$2,000	$2,000	$2,000	$2,000	$2,000
Total		**$118,800**	**$110,580**	**$105,000**	**$124,000**	**$386,000**	**$106,500**

RESPONSE

a) The fleet purchases were not made in 2015 and 2016 due to change in capital plans influenced by infrastructure priority and needs.

Inspections provided evidence of aggressive capital needs and greater capitalization of labour has occurred. 2014 had greater than expected budgeted expense with capital expenditure requirements on the sub-transmission lines.

2.0-VECC-15
Reference: E2/Attachment DSP/

a) Please provide the capital contributions (deferred revenue) for each year 2012 through 2017 forecast.

RESPONSE

a) The capital contributions (deferred revenue) for each of the following years is as follows:
   2012 - $0
   2013 - $0
   2014 - $0
   2015 - $20,123
   2016 - $19,666
   2017 - $19,209

3.0 OPERATING REVENUE (EXHIBIT 3)

3.0-VECC-16

Reference: Exhibit 3, page 6 (lines 3-4); page 10 (lines 17-18) and pages 13-15

a) Please explain (per page 6) how the "average" customer/connection count for each year was determined (e.g. monthly averages, average of opening and closing year values, etc.).
b) Please provide the actual 2016 customer/connection count for each customer class calculated on a similar basis.
c) Did the Intermediate Use customer cease operation in 2012 or was it transferred to another customer class?
d) Please re-do Tables 3-8 and 3-9 where:
   - 2016 actual values are included in the calculation of the geometric mean for Residential and GS<50 and the result is applied to the 2016 actual counts to forecast 2017
   - The actual averages for 2016 are used to forecast 2017 values for GS>50 and Street Lights.

RESPONSE

a) The "average" customer/connection count for each year was determined by averaging the year end values of the previous and current year.
b) Residential: 1,397
   General Service <50 kW: 231
   General Service>50 kW: 18
   Street lights: 625
c) The customer was transferred to the General Service >50 kW class.
d) The following provides the redone Tables 3-8 and 3-9 as per the direction in the question.

Table 3-8: Growth Rate in Customer/Connections					
Year	Residential	GS<50 kW	GS>50 kW	Intermediate	Street
Growth Rate in Customers/Connections					
2003					
2004	(1.4%)	(5.7%)	(2.3%)	0.0%	(0.6%)
2005	(0.9%)	(3.1%)	(2.4%)	0.0%	0.3%
2006	(0.8%)	(0.2%)	(2.4%)	0.0%	0.2%
2007	(0.8%)	(1.0%)	0.0%	0.0%	(0.1%)
2008	(0.8%)	(2.5%)	2.5%	0.0%	(0.2%)
2009	0.1%	0.6%	0.0%	0.0%	0.2%
2010	(0.8%)	(0.6%)	2.4%	0.0%	0.7%
2011	(1.1%)	(2.5%)	4.8%	0.0%	1.0%
2012	0.1%	0.9%	(9.1%)	0.0%	0.6%
2013	0.2%	0.4%	(10.0%)	0.0%	0.0%
2014	(0.1%)	(0.2%)	5.6%	0.0%	(0.4%)
2015	(0.4%)	0.0%	0.0%	0.0%	(0.8%)
2016	(0.6%)	(1.3%)	(7.9%)	0.0%	(0.4%)
Geometric Mean	(0.6%)	(1.2%)	(1.6%)	0.0%	0.0%

Table 3-9: Customer/Connection Forecast					
Year	Residential	GS<50 kW	GS>50 kW	Street Lights	Total
Forecast Number of Customers/Connections					
2017 Test	1,389	228	18	625	2,260

OPERATING REVENUE (EXHIBIT 3)

3.0-VECC-17
Reference: Exhibit 3, pages 2 and 8-9

a) Do the purchased power values used by Atikokan in its regression model include purchases from microFIT, FIT or other forms of local generation? If not, what would the monthly purchases of such generation be for the period 2002 to 2015?
b) Did Atikokan test to see whether some other economic activity variable (besides GDP) would be a statistically significant explanatory variable? If yes, what were the results? If not, why not?
c) How were the values for the customer/connections variable determined (i.e. what classes were included)?
d) If the Intermediate Use customer ceased operation in 2012, why wasn't the usage data for this customer simply removed from the power purchased values used in the regression equation (as opposed to introducing an Intermediate class flag)?
e) Please provide: i) the actual purchases for 2016; ii) the actual HDD and CDD value for 2016 and iii) the predicted purchases for 2016 using Atikokan's load forecast model.
f) Please provide an alternative regression model using the same explanatory variables (except the Intermediate class flag) and where the purchased power variable is adjusted to i) include any local generation per part (a) and ii) exclude the usage by the Intermediate Customer per part (d). Please also indicate what the resulting forecast 2017 power purchases and billed energy forecast would be prior to any adjustments for CDM

RESPONSE

a) The purchased power values used by Atikokan Hydro in its regression model do not include purchases from microFIT, FIT or other forms of local generation. The purchase of such generation did not start until 2010 for Atikokan Hydro. The following table outlines these MicroFIT purchases for the period 2010 to 2015.

Atikokan Hydro purchases from microFIT, FIT or other forms of local generation (kWh)													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	0	0	0	0	0	0	0	0	0	177	181	114	472
2011	139	407	918	895	1,444	3,180	3,294	3,353	3,641	2,839	2,298	1,461	23,869
2012	803	3,043	7,103	9,499	9,562	14,296	14,081	13,220	13,220	5,639	2,416	2,419	95,301
2013	1,400	2,827	5,643	10,245	13,095	14,750	13,561	15,304	12,834	6,477	2,291	1,199	99,626
2014	1,816	3,007	7,538	12,308	13,749	13,980	16,062	12,969	10,599	7,715	2,650	1,968	104,361
2015	1,103	4,098	12,777	15,959	15,482	16,605	15,371	14,200	13,438	8,499	4,187	1,499	123,218
2016	453	3,311	11,635	14,190	15,197	13,379	16,218	14,957	10,010	7,585	4,373	632	111,940

b) Atikokan Hydro did not test to see whether some other economic activity variable (besides GDP) would be a statistically significant explanatory variable since Atikokan Hydro believes including Number of Customer/Connections is also somewhat of an economic indicator. In addition, the resulting regression analysis with the variables used provided an Adjusted R Square of 92% which suggest adding other variable would not significantly increase the accuracy of the prediction equation.

c) The customer/connection variable assumes the total of the average customer and connections by rate class occurs in June of each year. The difference between the current and previous year's June values is divided by 12. The result is added to the previous year's June value to estimate the following July value. This practice is done for all subsequent months up to May of the current year. However, GS > 50 and Street Light classes Atikokan used actual as of July 2016 based on local knowledge that these values are more reflective of the values that will occur in the forecast period compared to those produced using the results of the analysis. As predicted at end of 2016, the GS >50 remains a count of 17. Atikokan anticipates this actual count to remain the same. There is no indication of any other new customers or significant change to the street light class.

d) This method was tested but it reduced the R Square to 58% and the Adjusted R Square to 57% which were unacceptable results.

e) Using the Atikokan Hydro's load forecast model provided in the application the following provides i) the actual purchases for 2016; ii) the actual HDD and CDD value for 2016 and iii) the predicted purchases for 2016. Please note the regression analysis has not been rerun in this case to reflect the actual 2016 data.

	Purchased	Heating Degree Days	Cooling Degree Days	Predicted Purchases
Jan-16	3,289,354	935	0	2,853,134
Feb-16	3,345,069	880	0	2,635,591
Mar-16	3,426,492	589	0	2,581,111
Apr-16	3,357,023	493	0	2,418,379
May-16	2,913,762	201	1	2,280,207
Jun-16	2,779,069	112	9	2,141,856
Jul-16	2,922,792	22	48	2,275,974
Aug-16	3,293,223	25	34	2,241,750
Sep-16	2,638,023	112	5	2,140,902
Oct-16	3,166,562	342	0	2,396,276
Nov-16	3,228,777	482	0	2,421,819
Dec-16	3,589,031	898	0	2,838,153

f) The following provides the statistical results of the alternative regression model

R Square	57.8%
Adjusted R Square	56.5%
F Test	43.3
MAPE (Monthly)	20.7%
Coefficient by Variable	
Heating Degree Days	782
Cooling Degree Days	3,181
Number of Days in Month	84,508
Number of Customers/Connections	6,226
Ontario Real GDP Monthly %	35,256
Constant	(20,136,583)
T-stats by Coefficient	
Heating Degree Days	11.7
Cooling Degree Days	2.3
Number of Days in Month	3.4
Number of Customers/Connections	6.5
Ontario Real GDP Monthly %	6.5
Constant	(6.7)

The resulting forecast 2017 power purchases would be 30,349,984 kWh and billed energy forecast would be 28,023,555 prior to any adjustments for CDM.

3.0-VECC-18

Reference: Exhibit 3, page 8 (Table 3-4) and pages 15-17

a) Please provide the actual billed energy (and kW where applicable) by rate class for 2016.
b) Please update Tables 3-10 and 3-11 to include actuals for 2016.
c) Please re-do Tables 3-12, 3-13 and 3-21 using:
   - 2016 actual usage per customer as the basis for the Residential, GS<50 and Street Light customer class forecasts.
   - an average of 2015 and 2016 usages per customer as the basis for the GS>50 customer class forecast.

RESPONSE

a) The following provides the actual billed energy (and kW where applicable) by rate class for 2016.

	Residential	GS<50 kW	GS>50 kW	Street Lights	Total
2016 kWh	8,885,318	4,951,711	21,235,005	462,429	35,534,463
2016 kW			47,908	1,432	49,340

b) The following provides Tables 3-10 and 3-11 to include actuals for 2016.

Table 3-10: Historical Annual Usage per Customer				
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lights**
Annual kWh Usage Per Customer/Connection				
2003	7,449	22,838	348,713	864
2004	7,323	22,133	340,763	842
2005	7,586	23,026	352,275	816
2006	7,392	22,344	346,738	785
2007	7,592	23,258	361,076	819
2008	7,216	22,680	351,523	789
2009	6,798	20,749	394,872	800
2010	6,973	21,121	356,612	776
2011	6,829	24,272	303,450	744
2012	6,699	22,785	336,138	739
2013	6,962	22,337	390,015	737
2014	6,905	22,718	413,259	738
2015	6,566	21,839	924,795	739
2016	6,383	21,623	1,249,118	740

Table 3-11: Growth Rate in Usage Per Customer/Connection				
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lights**
Growth Rate in Customer/Connection				
2003				
2004	(1.7%)	(3.1%)	(2.3%)	(2.5%)
2005	3.6%	4.0%	3.4%	(3.1%)
2006	(2.6%)	(3.0%)	(1.6%)	(3.9%)
2007	2.7%	4.1%	4.1%	4.4%
2008	(5.0%)	(2.5%)	(2.6%)	(3.6%)
2009	(5.8%)	(8.5%)	12.3%	1.4%
2010	2.6%	1.8%	(9.7%)	(3.0%)
2011	(2.1%)	14.9%	(14.9%)	(4.2%)
2012	(1.9%)	(6.1%)	10.8%	(0.6%)
2013	3.9%	(2.0%)	16.0%	(0.4%)
2014	(0.8%)	1.7%	6.0%	0.1%
2015	(4.9%)	(3.9%)	123.8%	0.2%
2016	(2.8%)	(1.0%)	35.1%	0.1%
Geometric Mean	(1.0%)	(0.4%)	8.5%	(1.3%)

c) The following provides Tables 3-12, 3-13 and 3-21 as requested.

Table 3-12: Forecast Annual kWh Usage per Customer/Connection				
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lights**
Forecast Annual kWh Usage per Customers/Connection				
2017 Test	6,383	21,623	1,086,956	740

Table 3-13: Non-normalized Weather Billed Energy Forecast					
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lights**	**Total**
NON-normalized Weather Billed Energy Forecast (GWh)					
2017 Test	8.8	4.9	18.5	0.5	32.7

Table 3-21: Alignment of Non-normal to Weather Normal Forecast					
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Street Lights**	**Total**
Non-normalized Weather Billed Energy Forecast (GWh)					
2017 Test	8.8	4.9	18.5	0.5	32.7
Weather Adjustment (GWh)					
2017 Test	1.0	0.5	(6.4)	(0.0)	(5.0)
CDM Adjustment (GWh)					
2017 Test	(0.13)	(0.23)	(0.03)		(0.4)
Weather Normalized Billed Energy Forecast (GWh)					
2017 Test	9.7	5.1	12.0	0.5	27.3

3.0-VECC-19

Reference: Exhibit 3, pages 18-20

a) Please provide Atikokan's 2015-2020 CDM Plan (page 18, line 13).
b) Please provide the IESO Report for Atikokan's Actual Verified 2015 CDM Results along with any reports from the IESO regarding the persisting effects of verified 2015 CDM programs.

RESPONSE

a) A copy of Atikokan's 2015-2020 CDM Plan is submitted separate from this response; named and filed as Atikokan_CDM_Plan_2015-2020_IR1_3-VECC-19_20170322.
b) Atikokan's IESO Reports for Atikokan's Actual Verified 2015 CDM Results is filed separate as

Atikokan_Final_2015_Annual_Verifiied_Results_Report_IR1_3-VECC-19_20170322

3.0-VECC-20
Reference: Exhibit 3, page 35 and Appendix

a) Please explain the material reduction in Retail Services Revenues (Account #4082) for 2016 and 2017 versus prior years' actual values.
b) Please explain the why the difference between Merchandise & Jobbing Revenue (#4325) and Merchandising & Jobbing Costs (#4330) has fallen from over $67,000 in 2015 to less than $36,000 in the 2017 forecast.
c) Please confirm whether the 2017 forecast value for Interest and Dividend Income (#4405) includes interest on regulatory accounts.
d) Please update Appendix 2-H for actual (unaudited) 2016 values.

RESPONSE

a) The material reduction in Retail Services Revenues (Account #4082) for 2016 and 2017 versus prior years' actual values has been the reduction in costs going forward beginning May 2016. Atikokan reviewed the cost amounts recorded and the OEB accounting handbook for 4082.
b) The difference between Merchandise and Jobbing Revenue and Merchandising & Jobbing Costs values being reduced is because these recoverable jobs are variable and often one time in nature and for this reason difficult to forecast.
c) Atikokan Hydro confirms that Interest and Dividend Income (#4405) includes the 2017 forecast value on regulatory accounts.
d) As requested, a copy of the updated Appendix 2-H for (unaudited) 2016 values is shown below.

Appendix 2-H
Other Operating Revenue

Unaudited

USoA #	USoA Description	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	215 Actual	Bridge Year[2]	Test Year
		2012	2012	2013	2014	2015	2016	2017
	Reporting Basis							
4235	**Specific Service Charges**	7,100	6,079	6,278	6,640	4,542	8,029	5,885
4225	**Late Payment Charges**	6,024	6,424	6,376	8,072	9,300	10,898	7,543
4082	**Retail Services Revenues**	5,000	6,414	6,986	6,449	6,447	2,933	2,820
4210	Joint Use Rent	34,911	31,625	**31,625**	31,625	31,625	32,609	32,609
4325	Recoverable - Income	75,000	66,608	70,407	128,340	91,224	73,406	70,000
4330	Recoverable - Expenses	- 20,000	- 29,758	- 58,208	- 87,015	- 23,705	- 42,589	- 34,351
4086	SSS Adminstration	4,200	5,148	**5,245**	5,285	4,884	4,877	4,875
	Interest	9,000	12,876	5,332	7,789	9,491	8,396	7,789
4355	Gain on Disposition of Property						-	
4360	Loss on Disposition of Property						- 22,432	
4390	Misc Revenue	4,000	5,246	3,768	6,755	6,631	2,676	5,600
Specific Service Charges		$ 7,100	$ 6,079	$ 6,278	$ 6,640	$ 4,542	$ 8,029	$ 5,885
Late Payment Charges		$ 6,024	$ 6,424	$ 6,376	$ 8,072	$ 9,300	$ 10,898	$ 7,543
Other Operating Revenues								
Other Income or Deductions								
Total		$ 13,124	$ 12,502	$ 12,654	$ 14,713	$ 13,842	$ 18,927	$ 13,428

Description	**2012 to 2015 same as load forcast**	**Account(s)**
Specific Service Charges:		4235
Late Payment Charges:		4225
Other Distribution Revenues:		4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:		4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

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

Account Breakdown Details

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

Account 4405 - Interest and Dividend Income

	2012 Board Approved	2012 Actual	2013 Actual	2014 Actual	215 Actual	Bridge Year[2]	Test Year
	2012	2012				2016	2017
Reporting Basis							
Short-term Investment Interest							
Bank Deposit Interest		$ 362	$ 1,147	$ 4,268	$ 6,890	$ 6,524	$ 5,789
Miscellaneous Interest Revenue RSVA Accts		$ 12,515	$ 4,185	$ 3,521	$ 2,602	$ 1,872	$ 2,000
Total	$ -	$ 12,876	$ 5,332	$ 7,789	$ 9,491	$ 8,396	$ 7,789

4.0 OPERATING COSTS (EXHIBIT 4)

4.0-VECC-21

Reference: E4/Pg.7

a) Please update the following tables for 2016 (unaudited) results:
   i. Appendix 2-JA (Table 4-4)
   ii. Appendix 2-JB (Table 4-5)
   iii. Appendix 2-JC (Table 4-6)
   iv. Appendix 2-L (Table 4-7)

RESPONSE

a) The following tables and been updated for 2016 unaudited results:
   i. Appendix 2-JA (Table 4-4)

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Unaudited Results	2017 Test Year
Reporting Basis	MIFRS	MIFRS					
Operations	$ 345,329	$ 148,936	$ 242,278	$ 256,339	$ 313,354	$ 378,171	$ 376,877
Maintenance	$ 41,177	$ 150,317	$ 170,353	$ 153,751	$ 131,756	$ 93,416	$ 120,741
SubTotal	**$ 386,506**	**$ 299,253**	**$ 412,631**	**$ 410,090**	**$ 445,110**	**$ 471,586**	**$ 497,618**
%Change (year over year)			37.9%	37.0%	8.5%	5.9%	5.5%
%Change (Test Year vs Last Rebasing Year - Actual)							66.3%
Billing and Collecting	$ 150,191	$ 162,936	$ 250,641	$ 180,534	$ 186,154	$ 163,038	$ 184,336
Community Relations	$ -	$ -	$ -	$ -	$ -		
Administrative and General	$ 493,303	$ 621,329	$ 387,923	$ 309,327	$ 422,985	$ 419,268	$ 415,442
SubTotal	**$ 643,494**	**$ 784,265**	**$ 638,564**	**$ 489,861**	**$ 609,139**	**$ 582,306**	**$ 599,778**
%Change (year over year)			-18.6%	-23.3%	24.3%	-4.4%	3.0%
%Change (Test Year vs Last Rebasing Year - Actual)							-23.5%
Total	**$ 1,030,000**	**$ 1,083,518**	**$ 1,051,195**	**$ 899,951**	**$ 1,054,249**	**$ 1,053,893**	**$1,097,396**
%Change (year over year)			-3.0%	-16.9%	17.1%	0.0%	4.1%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Unaudited Results	2017 Test Year
Operations	$ 345,329	$ 148,936	$ 242,278	$ 256,339	$ 313,354	$ 378,171	$ 376,877
Maintenance	$ 41,177	$ 150,317	$ 170,353	$ 153,751	$ 131,756	$ 93,416	$ 120,741
Billing and Collecting	$ 150,191	$ 162,936	$ 250,641	$ 180,534	$ 186,154	$ 163,038	$ 184,336
Community Relations	$ -	$ -	$ -	$ -	$ -		$ -
Administrative and General	$ 493,303	$ 621,329	$ 387,923	$ 309,327	$ 422,985	$ 419,268	$ 415,442
Total	**$ 1,030,000**	**$ 1,083,518**	**$ 1,051,195**	**$ 899,951**	**$ 1,054,249**	**$ 1,053,893**	**$1,097,396**
%Change (year over year)			-3.0%	-14.4%	17.1%	0.0%	4.1%

ii. Appendix 2-JB (Table 4-5)

OM&A	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Unaudited Results	2017 Test Year
Reporting Basis						
Opening Balance	$ 1,030,000	$ 1,083,518	$ 1,051,195	$ 899,951	$ 1,054,249	$ 1,053,892
Wages, Salaries, Progression, Benefits	-$ 12,158	-$ 67,973	$ 48,070	$ 80,005	-$ 28,452	$ 7,848
Vacation Accrual		$ 31,497	-$ 31,497	$ 11,801	$ 14,682	
Office Expense	-$ 3,999	-$ 750	$ 1,830	-$ 1,319		
Outside Professional Services	$ 39,625	-$ 166,005	-$ 27,954	$ 15,180	$ 18,579	
Insurance	$ 7,210	-$ 10,666	$ 976	$ 2,282		
Regulatory Expenses	-$ 20,571	-$ 17,511	-$ 2,981	$ 1,554	$ 10,197	$ 10,000
General Advertising Expense	-$ 699	-$ 255	$ 61	$ 1,410		
Miscellaneous General Expense	$ 9,183	-$ 4,842	-$ 6,245	$ 13,219		
Travel & Meal Allowance						
Maintenance of General Plant (operating)	$ 121,145	$ 17,024	-$ 6,004	$ 751	$ 2,641	
Misc. Distribution Expense				$ 6,091		
Lineman & Staff Training		-$ 6,242			$ 6,044	
O/H Distribution Supplies & Expenses	-$ 31,799	$ 29,089	$ 12,952	-$ 11,111	$ 7,551	
Line Operations & Maintenance	$ 884	-$ 1,264	-$ 221	$ 62		
Meter Expense	-$ 64,532	$ 3,990	$ 7,903	-$ 83	$ 2,952	
Maintenance of Dist & Station Equip	$ 1,387	$ 9,497	-$ 1,533	-$ 3,180	$ 2,536	
O/H - Right of Way; vegetation control		-$ 1,736	$ 175	$ 17,719	-$ 12,580	
Meter Maintenance	$ 3,767	$ 21,212	-$ 5,530	$ 19,994	-$ 11,501	$ 1,543
Maintenance of Line Transformers	-$ 661	$ 2,880	-$ 3,357	-$ 676	$ 3,557	
Bad Debt	-$ 5,790	$ 6,432	-$ 6,321	$ 471	$ 560	
Meter Reading	-$ 14,582	$ 60,121	-$ 61,208	$ 9,242		
Property Tax (6105) excluded OM&A					-$ 20,492	
Capitalization of OM&A		$ 13,400	-$ 165,463	$ 56,606		
Other	$ 25,108	$ 49,779	$ 95,105	-$ 65,720	$ 3,371	-$ 37,208
etc. (Insert additional rows as needed)	Adjusting 2016 unaudited impacted 2017 test year opening balance					$ 61,321
Closing Balance	$ 1,083,518	$ 1,051,195	$ 899,951	$ 1,054,249	$ 1,053,892	$ 1,097,396

iii. Appendix 2-JC (Table 4-6)

Programs	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Unaudited Results	2017 Test Year	Variance (Test Year vs. 2015 Actuals)	Variance (Test Year vs. Last Rebasing Year (2012 Board-Approved)
Reporting Basis									
Operations									
O/H Distribution Lines	235,093	138,804	211,447	244,042	288,604	261,734	324,558	35,954	89,465
Substation Equip/labour	1,292	2,136	15,530	9,216	1,097	32,873		-1,097	-1,292
O/H Distribution Supplies	42,915	5,624	9,645	2,376	8,721	49,598	42,089	33,368	-826
O/H Subtransmission	1,476							0	-1,476
Line Op & Maintenance		2,360		706		7,947		0	0
Meter Expense	64,554	12				13,584	10,230	10,230	-54,324
Operations Inventory Exp.			5,656					0	0
Misc. Distribution Expense					14,932	12,434		-14,932	0
Sub-Total	345,330	148,936	242,278	256,339	313,354	378,171	376,877	63,523	31,547
Maintenance									
Maint of Dist & Station Equip	599	1,986	11,483	9,950	6,770	9,305	13,800	7,030	13,201
Maint O/H Conduct & Devices	5,907	6,775	0			375	1,000	1,000	-4,907
Maintenance O/H	191	2,554	0	1,967	1,598			-1,598	-191
O/H ROW - Vegetation Maint.	30,669	65,530	59,742	17,549	36,801	50,240	72,000	35,199	41,331
Maintenance of Transformers	1,814	1,153	4,033	676	0	3,557		0	-1,814
Maintenance of Meters	1,996	5,763	23,679	32,650	52,561	29,938	33,941	-18,620	31,945
General Plant (Operating)		29,156	31,211	40,176				0	0
O/H Distribution Supplies		37,401	40,205	50,782	34,026			-34,026	0
Sub-Total	41,176	150,317	170,353	153,751	131,756	93,416	120,741	-11,015	79,565
Billing & Collecting									
Retailer Service Expense	2,727	2,310	2,303	2,310	2,421	3,060	3,045	624	318
Meter Read - Material & Lab Exp	45,939	9,353	65,697	11,988	20,565	7,367	8,976	-11,589	-36,963
Meter Read - MV 90		12,403	20,981	29,013	14,147	17,516	18,389	4,242	18,389
Meter Service Provider Services		9,600	4,800	4,800	4,800	4,800	4,800	0	4,800
Customer Billing	94,081	127,609	138,732	128,103	127,999	124,911	143,126	15,127	49,045
Bad Debt	5,444	-346	6,432	110	582	1,141	6,000	5,418	556
Misc. Customer Accounts	2,000	2,006	11,697	4,210	15,641	4,243			
Sub-Total	150,191	162,936	250,641	180,534	186,154	163,038	184,336	-1,818	34,145
Administration									
Admin salaries & expenses	252,470	350,565	221,842	186,959	219,678	211,653	206,254	-13,424	-46,216
Office Expenses	8,153	4,154	3,404	5,234	3,915	3,945	4,500	585	-3,653
Outside Services	62,639	145,111	56,301	28,347	43,526	62,105	57,150	13,624	-5,489
Regulatory Expenses	53,064	24,834	14,982	12,001	13,555	23,752	25,103	11,548	-27,961
Property Insurance	9,116	16,326	17,558	8,282	8,281	7,041	8,572	291	-544
General Advertising Exp.		531	441	337	1,747	422	1,800	53	1,800
Misc. General Expense	1,230	25,168	21,047	15,281	26,118	25,882	18,085	-8,033	16,855
Travel/Meal Allowance		2,064	1,267	863	3,245	3,170	2,400	-845	2,400
Operating Expenses	41,271		0		40,927	23,076	28,948	-11,979	-12,323
Employee Pension - Omers	45,229	52,576	51,080	52,025	61,992	58,222	62,630	638	17,401
Electrical Safety Authority Fee	2,082							0	-2,082
Sub-Total	475,254	621,329	387,923	309,327	422,984	419,268	415,442	-7,542	-59,812
Miscellaneous								0	0
Total	**1,011,951**	**1,083,518**	**1,051,195**	**899,951**	**1,054,249**	**1,053,892**	**1,097,396**	**43,147**	**85,445**

iv. Appendix 2-L (Table 4-7)

	Last Rebasing Year - 2012-Board Approved	Last Rebasing Year - 2012-Actual	2013 Actuals	2014 Actuals	2015 Actuals	2016 Unaudited Results	2017 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs							
O&M	$ 386,506	$ 299,253	$ 412,631	$ 410,090	$ 445,110	$ 471,586	$ 497,618
Admin Expenses	$ 643,494	$ 784,265	$ 638,564	$ 489,861	$ 609,139	$ 582,306	$ 599,778
Total Recoverable OM&A from	$ 1,030,000	$ 1,083,518	$ 1,051,195	$ 899,951	$ 1,054,249	$ 1,053,892	$ 1,097,396
Number of Customers [2,4]	2,297	2,300	2,300	2,295	2,283	2,271	2,260
Number of FTEs [3,4]	8	8	7	8	9	8	8
Customers/FTEs	287.13	287.50	328.57	286.88	253.67	283.88	282.50
OM&A cost per customer							
O&M per customer	168.2655638	130.11	179.4047826	178.6884532	194.9671485	207.6558168	220.1849558
Admin per customer	280.1454071	340.9847826	277.6365217	213.4470588	266.8151555	256.4095112	265.3884956
Total OM&A per customer	448.4109708	471.0947826	457.0413043	392.135512	461.782304	464.065328	485.5734513
OM&A cost per FTE							
O&M per FTE	48,313.25	37,406.63	58,947.29	51,261.25	49,456.67	58,948.30	62,202.25
Admin per FTE	80,436.75	98,033.13	91,223.43	61,232.63	67,682.11	72,788.25	74,972.25
Total OM&A per FTE	128,750.00	135,439.75	150,170.71	112,493.88	117,138.78	131,736.55	137,174.50

4.0-VECC-22

Reference: E4/pg.13

a) Who did Atikokan switch insurance carriers from/to in order to make savings in 2014?

RESPONSE

a) Atikokan switched from Gillons' insurance to the Mearie Group to make savings.

4.0-VECC-23
Reference: E4/Table 4-6

a) Please explain the requirement for significantly more OM&A spending in 2017 as compared to 2012 Board approved/actuals in the following areas:
   i. Vegetation Maintenance – please also explain why the amounts for this declined sharply in 2014 and 2015;
   ii. Customer billing (94k vs 143k);
   iii. OH/Distribution lines (235k vs 324k) – please also explain why 2012 actuals for this category were significantly below Board approved.

RESPONSE

a) The 2017 OM&A spending requirement is significantly more than the 2012 Board approved and explained in the following areas:
   i. Vegetation Maintenance declined sharply in 2014 and 2015 as a result of an apprentice; and apprentice wage subsidy's Atikokan Hydro was eligible for. Also unfavorable weather conditions can negatively impact the amount of vegetation maintenance.
   ii. Customer Billing (94k vs 143k) – This is attributable to inflationary increases but mainly the difference is smart meter customer billing expenses (payable to smart metering service provider) that were in a combination of OM&A and smart meter variance accounts until final board approval but these expenses are also impacted by increases.
   iii. Atikokan notes the OH/Distribution lines is significantly below the board approved. The 2012 actual O/H Distribution lines was 138,804 as noted in Table 4-6. This is mainly a result of reallocations, for example, not expensing employee overheads such as benefits and payroll burdens in this account but rather in administration.

4.0-VECC-24
Reference: E4/pg.14

a) Please provide any EDA membership fees paid for each of the years 2012 through 2017 (forecast).
b) Please provide the same for fees paid to the Utility Standards Forum.
c) Does Atikokan pay any other (corporate) membership fees? If yes, please identify these.

RESPONSE

a) The EDA membership fees paid for years 2012 through 2017 are as follows:
2012 - $5,120
2013 - $5,400
2014 - $5,600
2015 - $5,800
2016 - $5,900
2017 - $6,000

b) The fees paid to Utility Standards Forum are as follows:
2012 - $0
2013 - $0
2014 - $0
2015 - $0
2016 - $11,250
2017 - $8,750

c) The other membership fees Atikokan pays includes yearly fees to the Atikokan Chamber of Commerce as follows:
2012 - $150
2013 - $150
2014 - $150
2015 - $150
2016 - $150
2017 - $150

4.0-VECC-25

Reference: E4/pg.20 Table 4-16

a) Please update appendix 2-K to show 2016 actuals and to include a row showing the total compensation capitalized in each of the years 2012 through 2017 (forecast).

RESPONSE

a) Appendix 2-K is updated to show 2016 unaudited actuals and includes a row showing the total compensation capitalized.

	Last Rebasing Year - 2012- Board Approved	Last Rebasing Year - 2012- Actual	2013 Actuals	2014 Actuals	2015 Actuals	2016 Unaudited Actuals	2017 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)							
Non-Management (union and non-union)	8	8	7	8	9	8	8
Total	8	8	7	8	9	8	8
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)							
Non-Management (union and non-union)	$562,651	$548,936	$488,418	$534,594	$602,852	$577,378	$609,591
Total	$562,651	$548,936	$488,418	$534,594	$602,852	$577,378	$609,591
Total Benefits (Current + Accrued) [2]							
Management (including executive)							
Non-Management (union and non-union)	$111,581	$113,138	$105,683	$107,577	$119,324	$116,346	$127,630
Total	$111,581	$113,138	$105,683	$107,577	$119,324	$116,346	$127,630
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Non-Management (union and non-union)	$674,232	$662,074	$594,101	$642,171	$722,176	$693,724	$737,221
Total	$674,232	$662,074	$594,101	$642,171	$722,176	$693,724	$737,221
Compensation Capitalized							
Total Compensation Capitalized		$ 52,031	$ 46,612	$111,229	$ 92,282	$ 85,404	$ 70,184

4.0-VECC-26

Reference: E4/pg. 25

a) Why did the 2014 shared service costs with Enercom – especially streetlight maintenance- spike in 2014?

RESPONSE

a) The 2014 shared services costs with Enercom; especially in street lighting maintenance spiked in 2014 because 80 poles were purchased for streetlights.

4.0-VECC-27
Reference: E4/

a) Please provide a table showing the property taxes paid for each of the years 2012 through 2017 (forecast).
b) Please provide a table showing the actual PILs paid for each of the years 2012 through 2017 (forecast).

RESPONSE

a) The property tax paid in the historical years 2012 through 2017 including the 2017 forecast year are as follows:

Property Taxes Paid					
2012	2013	2014	2015	2016	2017*
$7,903.2	$26,420.08	$32,465.91	$18,261.56	$20,491.99	$21,488.60

*2017 Forecasted property tax used OEB inflation rate of 1.95% as the actual 2017 property tax amounts are not known or predicted. $19,624.29 was used for the 2016 Bridge year Property Tax Amount.

b) The PILS paid in the historical years 2012 through 2017 including the 2017 forecast year are as follows:

PILS Paid					
2012	2013	2014	2015	2016	2017*
3,468	$0	12,719	32,311	32,276	32,000

4.0-VECC-28

Reference: Exhibit 4, LRAMVA Work Form

a) Please provide the a copy of the source for the persisting kWh values used in Table 12 of the LRAMVA Work Form, Tab 6 - Persistence Rates.
b) Please provide any reports from the IESO regarding the persisting savings of 2011-2014 CDM programs.
c) Why don't the first year values in Table 12 (Tab 6) match the results reported in the IESO Report or Tab 4?
d) The LRAMVA Work Form (2011-2014 LRAM Tab) values do not all reconcile with those reported in the IESO Report (Exhibit 4, Attachment C). For example, the reported Residential savings for 2013 for 2013 CDM programs in the LRAMVA Work Form (7,531 kWh) does not appear to include the subsequent adjustment of 635 kWh noted in the IESO Report. Please review and correct the inputs to the LRAMVA model as needed.

RESPONSE

a) Persisting kWh values used in Table 12 of the LRAMVA work Form, Tab 6 – Persistence Rates come from the final report from the IESO Final Report 2011-2014.
b) The final reports from the IESO regarding persisting savings of 2011-2014 CDM programs will be filed in excel as
   Atikokan_2011-2014_CDM_Reports_Results_IR1_3-VECC-28_20170322
c) The first year values in Table 12 (tab 6) did not match because Atikokan used the Draft Final instead of the Verified Final report.
d) The LRAMVA Work Form has been updated to reflect the correct values. See the updated live excel model.

4.0-VECC-29

Reference: Exhibit 4, LRAMVA Work Form
EB-2011-0293, Load Forecast Model and Board Decision

a) Please confirm that in its EB-2011-0293 Decision (page 8) the Board accepted Atikokan's proposed CDM adjustment for its 2012 Rate Application.
b) Please confirm that this adjustment was based on 100% of the forecast savings from 2011 and 2012 programs – totaling 232,000 kWh and broken down as follows:
    - Residential – 110,787 kWh
    - GS<50 – 55,193 kWh
    - GS>50 – 60,654 kWh
    - Street Light – 5,367 kWh
c) Please confirm that these values were not used in Tab 2 of the LRAMVA Work Form as filed and, if so, provide a revised/corrected version of the work form.

RESPONSE

a) Atikokan Hydro confirms that in its EB-2011-0293 (page 8) the Board accepted Atikokan's proposed CDM adjustment for its 2012 Rate Application.
b) Atikokan Hydro confirms that this adjustment was based on 100% of the forecast savings from 2011 and 2012 programs – totaling 232,000 kWh. This was Table 5 LRAM Variance Account Values for 2012 and until next rebasing. DRO EB-2011-0293 page 12 of 28 dated July 16, 2012.
c) Atikokan Hydro confirms these values were not used in Tab 2 of LRAMVA work form.

5.0 COST OF CAPITAL AND RATE OF RETURN (EXHIBIT 5)

5.0-VECC-30
Reference: E5

a) What is the basis of the TD Trust car loan estimate rate of 4.54% (i.e. how was this derived)?
b) Please provide the current TD prime rate.

RESPONSE

a) The basis of the TD Trust car loan estimate rate of 4.54% is consistent with the Board's current published Cost of Capital parameters dated October 15, 2015. The Cost of Capital Parameters for 2016 Applications was used since the 2017 Rate Application Parameters had not yet been disclosed.
b) The current TD Prime rate is 2.70%.

5.0-VECC-31
Reference: E5

a) When are the two vehicle loans (rows 4 and 5 in Table 5) expected to be finalized.
b) If the loans are not in place until Dec 1, 2017 why has Atikokan calculated the long-term debt rate based on 12 months (rather than 1 month) of interest?

RESPONSE

a) The two vehicle loans (rows 4 and 5 in Table 5) are expected to be finalized over a 10 and 5 year loan period; respectively 2027 and 2022.
b) Atikokan unintentionally calculated the long-term debt rate based on 12 months rather than 1 month of interest (in service date of Dec 1, 2017).

5.0-VECC-32

Reference: E5/pg.4/Table 5-1

a) Please recalculate Table 5-1 using the Board October 2016 cost of capital parameters for long-term debt (3.72%) for the TD 10 year loan and 5 year loan and prorate for a December 1, 2017 start date

b) Please recalculate Appendix 2-AO using the response to (a) and the Board October 2016 ROE value of 8.78%.

RESPONSE

a) Table 5-1 is recalculated below, using the Board October 2016 cost of capital parameters for long-term debt of 3.72%. Respectively Atikokan has also recalculated table Table 5-1 a second time prorating the interest for one month to reflect the start date of the loans but further prorating the principal loans to calculate a consistent in and reasonable weighted cost of debt.

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Smart Meters/Capital Investment	Atikokan Enercom Inc	Affiliated	Variable Rate	7-Apr-09		$ 342,000	1.70%	$ 5,814.00
2	International Cab, Chassis	TD Canada Trust	Third-Party	Variable Rate	1-Dec-09	10	$ 56,614	3.70%	$ 2,094.71
3	Garage	TD Canada Trust	Third-Party	Variable Rate	1-Dec-09	15	$ 131,004	3.95%	$ 5,174.64
4	International Cab, Chassis	TD Canada Trust	Third-Party	Variable Rate	1-Dec-17	10	$ 300,000	3.72%	$ 930.00
5	Service Vehicle	TD Canada Trust	Third-Party	Variable Rate	1-Dec-17	5	$ 60,000	3.72%	$ 186.00
6	Total 2017 Long Term Debt						$ 889,617	1.60%	$ 14,199.35

Year 2017

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Smart Meters/Capital Investment	Atikokan Enercom Inc	Affiliated	Variable Rate	7-Apr-09		$ 342,000	1.70%	$ 5,814.00
2	International Cab, Chassis	TD Canada Trust	Third-Party	Variable Rate	1-Dec-09	10	$ 56,614	3.70%	$ 2,094.71
3	Garage	TD Canada Trust	Third-Party	Variable Rate	1-Dec-09	15	$ 131,004	3.95%	$ 5,174.64
4	International Cab, Chassis	TD Canada Trust	Third-Party	Variable Rate	1-Dec-17	10	$ 25,000	3.72%	$ 930.00
5	Service Vehicle	TD Canada Trust	Third-Party	Variable Rate	1-Dec-17	5	$ 5,000	3.72%	$ 186.00
6	Total 2017 Long Term Debt						$ 559,617	2.54%	$ 14,199.35

b) Appendix 2-AO has been recalculated using the Board's Cost of Capital parameters for 2017 Rate Applications released October 27, 2016

The OEB determined Cost of Capital parameters are as follows:

ROE	8.78%
LT Debt rate	3.72%
ST Debt rate	1.76%

Year: 2017 Test Year

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$1,956,308	2.54%	$49,690
2	Short-term Debt	4.00%	(1)	$139,736	1.76%	$2,459
3	**Total Debt**	60.0%		$2,096,045	2.49%	$52,150
	Equity					
4	Common Equity	40.00%	(2)	$1,397,363	8.78%	$122,688
5	Preferred Shares		(2)	$ -		$ -
6	**Total Equity**	40.0%		$1,397,363	8.78%	$122,688
7	**Total**	100.0%		$3,493,408	5.00%	$174,838

6.0 CALCULATION OF REVENUE DEFICIENCY/SURPLUS (EXHIBIT 6)

7.0 COST ALLOCATION (EXHIBIT 7)

7.0-VECC-33

Reference: Exhibit 7, pages 3-4
Cost Allocation Model – as filed by Atikokan

a) Please explain why there are no costs recorded in Account 1855. Is it because all customer classes "pay" for the cost of Services or are these costs recorded in another account? If the later, in what account are they recorded and for what customer classes are such costs incurred?
b) What is the basis for the relative meter reading weights used in Tab I7.2 of the Cost Allocation Model?
c) With respect to Tab I6.2 of the Cost Allocation model, please confirm that each Street Light device is separately connected to Atikokan's distribution system.

RESPONSE

a) Atikokan does not use Account 1855 and historically have not. Atikokan records costs in 1830 for all customers.
b) The basis of the meter reading weights used in Tab 17.2 of the CA Model are those used in the previous Cost of Service Rate Application. Meter reading and billing practices have not substantially changed.
c) Streetlight devices are separately connection to Atikokan's distribution system; we do not use a relay system.

7.0-VECC-34

Reference: Exhibit 7, page 4 (lines 20-24) Cost Allocation Model, Tab O3.6

a) Does Atikokan perform all the meter reading and billing required for microFIT customers internally or is some of this activity contracted out? If part is contracted out please outline what services are provided externally and what the cost per customer per month is.

b) When was the uniform microFIT charge last updated by the OEB and when does Atikokan expect the next update to be available?

RESPONSE

a) Atikokan performs all the meter reading and billing required for microFIT customers internally.

b) The uniform microFIT charge was last updated by the OEB for 2013 rates; May 1, 2013. Atikokan does not know when to expect the next update to be available for the uniform microFIT charge.

7.0-VECC-35

Reference: Exhibit 8, pages 11-12
Cost Allocation Model, Tab I4

a) Exhibit 8 states that Atikokan owns/maintains 23 kilometers of 44 kV sub transmission line. However the CA model does not show any break out of sub transmission assets for Accounts #1830 or #1835. Please explain why.
b) Please revise Tab I4 of the CA model to include a breakout of sub transmission based on the cost of this line for accounts #1830 and #1835 and provide the resulting revised CA model results.

RESPONSE

a) The CA model does not show any break out of sub transmission assets because Atikokan has not historically broken out the assets in accounts 1830 and 1835. Atikokan records all costs in 1830.
b) Atikokan as requested revised Tab I4 of the CA model to include the breakout of sub transmission based on the cost of this line for accounts #1830 and #1835.
The resulting revised CA model results will be filed in a live excel model named Atikokan_2017_ Cost Allocation_IR1_ 7-VECC-35_20170322

8.0 RATE DESIGN (EXHIBIT 8)

8.0-VECC-36

Reference: Exhibit 8, page 14

a) How many of Atikokan's Residential customers are currently enrolled with the OESP and, of these, how many have usage at/below the 10th percentile?

b) Why is it appropriate to consider the removal of the provincial portion in the determination of the customer bill impacts when this action occurred part way through Atikokan's 2016 rate year?

c) Please re-do Table 2-9 assuming the Residential fixed-variable split was held constant at the current values.

RESPONSE

a) Atikokan has 98 Residential customers currently enrolled with the OESP. One of these OESP customers have usage at or below the 10th percentile.

b) Atikokan believes it is appropriate to share all relevant customer bill impacts to customers.

c) Atikokan has revised Table 2-9 assuming the Residential fixed-variable split was held constant at the current values.

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	141	kWh
Demand	-	kW
Current Loss Factor	1.0778	
Proposed/Approved Loss Factor	1.0945	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 36.95	1	$ 36.95	$ 42.85	1	$ 42.85	$ 5.90	15.97%
Distribution Volumetric Rate	$ 0.0104	141	$ 1.47	$ 0.0121	141	$ 1.71	$ 0.24	16.35%
Fixed Rate Riders	$ 1.06	1	$ 1.06	$ 1.71	1	$ 1.71	$ 0.65	61.32%
Volumetric Rate Riders	$ -	141	$ -	$ -	141	$ -	$ -	
Sub-Total A (excluding pass through)			$ 39.48			$ 46.27	**$ 6.79**	**17.20%**
Line Losses on Cost of Power	$ 0.1114	11	$ 1.22	$ 0.1114	13	$ 1.48	$ 0.26	21.47%
Total Deferral/Variance Account Rate Riders	$ 0.0008	141	$ 0.11	-$ 0.0032	141	$ (0.45)	$ (0.56)	-500.00%
GA Rate Riders				$ -	141	$ -	$ -	
Low Voltage Service Charge	$ -	141	$ -		141	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 41.60**			**$ 48.09**	**$ 6.49**	**15.60%**
RTSR - Network	$ 0.0046	152	$ 0.70	$ 0.0046	154	$ 0.71	$ 0.01	1.55%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0035	152	$ 0.53	$ 0.0035	154	$ 0.54	$ 0.01	1.55%
Sub-Total C - Delivery (including Sub-Total B)			**$ 42.83**			**$ 49.34**	**$ 6.51**	**15.19%**
Wholesale Market Service Charge (WMSC)	$ 0.0036	152	$ 0.55	$ 0.0036	154	$ 0.56	$ 0.01	1.55%
Rural and Remote Rate Protection (RRRP)	$ 0.0013	152	$ 0.20	$ 0.0021	154	$ 0.32	$ 0.13	64.04%
Standard Supply Service Charge	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)								
Ontario Electricity Support Program (OESP)	$ 0.0011	154	$ 0.17	$ 0.0011	154	$ 0.17	$ -	0.00%
TOU - Off Peak	$ 0.0870	92	$ 7.97	$ 0.0870	92	$ 7.97	$ -	0.00%
TOU - Mid Peak	$ 0.1320	24	$ 3.16	$ 0.1320	24	$ 3.16	$ -	0.00%
TOU - On Peak	$ 0.1800	25	$ 4.57	$ 0.1800	25	$ 4.57	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 59.70**			**$ 66.34**	**$ 6.64**	**11.13%**
HST	13%		$ 7.76	13%		$ 8.62	$ 0.86	11.13%
Total Bill on TOU			**$ 67.46**			**$ 74.97**	**$ 7.51**	**11.13%**

9.0 DEFERRAL AND VARIANCE ACCOUNTS (EXHIBIT 9)

9.0-VECC-37

Reference: Exhibit 2/pg.30

a) Is Atikokan seeking to close account 1555 (Stranded Assets related to smart meters)?
b) Please confirm the approved SMRR rate rider of $0.39 was only in place from July1, 2012 to June 30, 2015.

RESPONSE

a) Atikokan Hydro is seeking to close account 1555 Stranded Assets related to smart meters upon the full disposition of Stranded Meters.
b) Atikokan Hydro confirms the dates in EB-2011-0293 for Stranded Meter Rate Rider; July1, 2012 to June 30, 2015. However, implementation date was delayed to September 1, 2012; extending the sunset to August 31, 2015; for a total recovery period of 36 months.

9.0-VECC-38
Reference: E9

a) Please provide a table shown the amounts sought for May 1, 2017 disposition including any adjustments for 2016. See below for a sample table format (figures are demonstrative only)

RESPONSE

a) As requested the table below shows the amounts sought for May 1, 2017.

Accounts Submitted for 2017 Dipsostion						
Account Description	USoA	Principal	Interest	2016 Adjustments	Projected Interest Jan 2016 - Apr 2017	Total Claim
Group 1						
Smart Metering Entity Charge Variance Account	1551	33	-	-	-	33
RSVA-Wholesale Marketing Service Charge	1580	- 65,812	- 572		- 970	- 67,354
RSVA-Retail Trasnmission Network Charge	1584	5,868	- 36		86	5,918
RSVA-Retail Trasnmission Connection Charge	1586	- 1,482	- 53		21	- 1,514
RSVA-Power (Excluding Global Adj.)	1588	- 30,928	- 599		- 454	- 31,981
RSVA-Global Adjustment	1589	45,115	289		662	46,066
Disposition Rec/Ref of Regulatory Balances	1595					-
Subtotal Group 1 Accounts		**- 47,206**	**- 971**	**-**	**- 655**	**- 48,832**
Group 2 Accounts						
Other Regulaory Assets - IFRS Trasnstion Costs	1508	36,422	1,486	19,289	534	57,731
Retail Cost Variance Account - Retail	1518	12,166	435		179	12,780
Retail Cost Variance Account - STR	1548	9,071	216		133	9,420
Smart Meter Capital/Recovery -Stranded Meters	1555	57	518		1	576
Subtotal Group 2 Accounts		**57,716**	**2,655**	**19,289**	**847**	**80,507**
LRMA Variance Account	1568	1,487	115	3,445	72	5,119
Total Other Accounts		**1,487**	**115**	**3,445**	**72**	**5,119**
Total		**11,997**	**1,799**	**22,734**	**264**	**36,794**