Exhibit 1 – Administration

1-VECC-1

Reference: Exhibit 1, page 94

a) Please update the KWHI scorecard for the 2018 actual results.

Efficiency Assessment, Total Cost Per Customer, Total Cost per km of Line, and New Cumulative Energy Savings are not yet available for 2018.

Scorecard - Kitchener-Wilmot Hydro Inc.

			2012	2013	2014	2015	2016	2017	2018 Forecast	2018 Actual
Service Quality	New Residential/Small Business Services Connected on time		91.30%	91.30%	90.90%	90.30%	92.50%	98.93%	99.14%	99.14%
	Scheduled Appointments Met On Time		96.70%	96.10%	95.30%	96.20%	97.50%	97.93%	99.20%	99.18%
	Telephone Calls Answered On Time		76.40%	78.60%	80.40%	78.10%	78.40%	92.80%	91.77%	91.90%
Customer Satisfaction	First Contact Resolution				98.60%	98.90%	99.40%	99.60%	99.03%	99.03%
	Billing Accuracy				100.00%	100.00%	100.00%	99.58%	97.87%	97.37%
	Customer Satisfaction Survey Results			A	A	A	A	A	A	A
Safety	Level of Public Awareness					83.00%	83.00%	83.00%	83.00%	83.00%
	Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C	C	C	C
	Serious Electrical Incident Index	Number of General Public Incidents	1	0	1	0	0	0	3	3
		Rate per 10, 100, 1000 km of line	0.532	0.000	0.526	0.000	0.000	0.000	1.524	1.524
System Reliability	Average Number of Hours that Power to a Customer is Interrupted		0.97	0.87	0.72	0.57	1.11	0.92	0.70	0.70
	Average Number of Times that Power to a Customer is Interrupted		0.88	0.69	1.03	0.77	1.11	1.03	0.97	0.97
Asset Management	Distribution System Plan Implementation Progress				In Progress	In Progress	In Progress	In Progress	In Progress	In Progress
Cost Control	Efficiency Assessment		2	2	2	2	2	2	2	
	Total Cost per Customer		$ 450	$ 466	$ 483	$ 481	$ 494	$ 487	$ 509	
	Total Cost per Km of Line		$ 21,225	$ 22,062	$ 23,132	$ 23,150	$ 23,866	$ 23,707	$ 25,041	
Conservation & Demand Management	New Cumulative Energy Savings					20.68%	36.61%	83.39%	94.88%	
Connection of Renewable Generation	Renewable Generation Connection Impact Assessments completed on Time		100%	100%	100%	100%	100%	100%	100%	100%
	New Micro-embedded Generation Facilities connected on time			100%	100%	100%	100%	100%	100%	100%
Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		2.05	2.14	1.95	1.97	1.96	1.99	2.01	2.01
	Leverage: Total Debt (Includes Short-term and Long-term Debt) to Equity Ratio		0.74	0.69	0.65	0.61	0.57	0.54	0.51	0.51
	Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.85%	9.85%	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
		Achieved	10.91%	8.94%	10.87%	11.47%	10.18%	9.59%	9.06%	9.06%

1-VECC-2

a) Please provide the total cost of the customer engagement work completed for this application. Please show separately external and internal costs of this work

To date, the amount of customer engagement expense that will be deferred as a result of this application is $129,595. This work was all external costs. Internal costs were included in OM&A and were not deferred.

Exhibit 2 – Rate Base

2-VECC-3

Reference: Exhibit 2, Table 2.9.3.1-1 / Appendix 2-AA

a) Please confirm that the 2018 capital expenditure figures represent actual (not forecast) amounts. If this is not confirmed please update these tables for actual results.

The 2018 capital expenditure figures shown in Exhibit 2, Table 2.9.3.1-1 / Appendix 2-AA represent actual amounts.

2-VECC-4

Reference: Exhibit 2, EB-2013-0147 Exhibit 2, Tab 1, Schedule 2, pg. 34

a) Please confirm (or correct) that the prior cost of service application EB-2013-0147 KWH had put forward a proposal to recover $300,000 to replace its legacy CIS Application. Please explain how that proposal relates to the new proposal.

KWHI has been planning to replace or redesign its legacy CIS application for several years. The amount of $300,000 put forward in the 2014 application was an estimate to initiate an architectural review and redesign of the CIS to provide separation between the customer (the individual or commercial entity named on the bill) and the service which defines the geographic location to which electrical service is delivered. The current proposal (2020 application) is to replace the legacy CIS with a commercial application. The estimated costs are based on the selection of a preferred application and vendor from an RFP process.

2-VECC-5

Reference: Exhibit 2, Page 219

The General Information on Project (5.4.3.2.A) for the CIS project shows only $1.675 million being expended on the CIS project in 2020. The evidence explains this is a $6.7 million project. Appendix 2-AA shows $5.190 million and $2.335 million being spent on IT/OT systems in 2019 and 2020 respectively.

a) Please provide a detailed budget for the CIS replacement showing all spending in the 2018 through 2020 period for capital and any incremental OM&A (including incremental licensing fees).

	2019		2020				2021	
Type	June-September	Q4	Q1	Q2	Q3	Q4	Q1	Total
Capital	2,473,900	1,150,200	969,400	957,800	1,076,100	770,100	362,500	7,760,000
Administration	(65,500)	(202,900)	(185,600)	(204,500)	(229,800)	(164,400)	(77,400)	(1,130,100)

The discrepancy of cost estimates between the DSP, Exhibit 2 and the presentation to KWHI's Board of Directors is a timing issue between when the capital budgets were finalized, when the DSP was being developed, the timing of the filing of KWHI's Cost of Service Application and the finalizing of the actual CIS contracts.

The estimated capital cost that KWHI included in its 2020 rate application was $6.7M. This was an estimated full project cost. At the time that its capital budgets were finalized for its Cost of Service application, KWHI was still in negotiations with various CIS vendors and the full project cost was not yet fully known.

On May 31, 2019, KWHI made its decision to move forward with Oracle CC&B as its chosen CIS solution. It was not until the end of June that all negotiations with the vendors was completed and the final project costs fully known.

The final project capital costs are now estimated to be $7.76M. The incremental annual software support and managed services costs will be $371,800.

2-VECC-6

Reference: Exhibit 2, Appendix 2-AA

a) Please provide a table showing for each of the System Access categories:
- LRT Relocations,
- Roadway Relocations,
- Underground Residential Distribution; and,
- Commercial/Industrial/Apartment Services,

the capital contributions for each category in each year 2014 through 2020 (forecast). Please provide separately the residual capital contributions for each year associated with the remaining five system access categories and the total capital contributions for all capital projects in the period 2014 through 2020.

While the estimated amount of capital contributions is budgeted and forecasted at the program level, the actual amount collected isn't categorized by programs except for the LRT program. Due to the scope and nature of the LRT program, it was decided early in the implementation stage to track costs associated with this program separately. The table below shows the actual capital contributions for 2014 through 2018 as a lump sum (LRT excluded) and the forecasted amount for 2019 through 2020 on a program level.

Capital Contribution Table							
	2014	**2015**	**2016**	**2017**	**2018**	**2019F**	**2020F**
Programs	**Amount ($)**						
System Access							
LRT Relocations	3,234,441	4,826,705	2,068,891	5,207,026	-	-	-
Other Capital Contributions	3,463,871	4,766,541	6,881,109	894,068	4,696,000	-	-
Roadway Relocations	-	-	-	-	-	465,000	510,000
Underground Residential Distribution	-	-	-	-	-	2,580,000	2,580,000
Commercial, Industrial & Apartment Services	-	-	-	-	-	663,000	769,000
Revenue Meters & Generation Connections	-	-	-	-	-	-	-
System Expansion - Customer Growth	-	-	-	-	-	60,000	170,000
System Access Sub Total	**6,698,312**	**9,593,246**	**8,950,000**	**6,101,094**	**4,696,000**	**3,768,000**	**4,029,000**

2-VECC-7

Reference: Exhibit 2 Distribution System Plan, page 207 (PDF 346) Table 4-33

a) Please reconcile Table 4-33 with Appendix 2-AA for the year 2020.

See response to 2-Staff-13.

2-VECC-8

Reference: Exhibit 2, PDF pg. 549

Please confirm the forecast capital contribution for the Underground System Expansion to Supply New Developments is $170,000 for a project estimated to have a total cost of $1.7million. Please explain how this capital contribution was estimated.

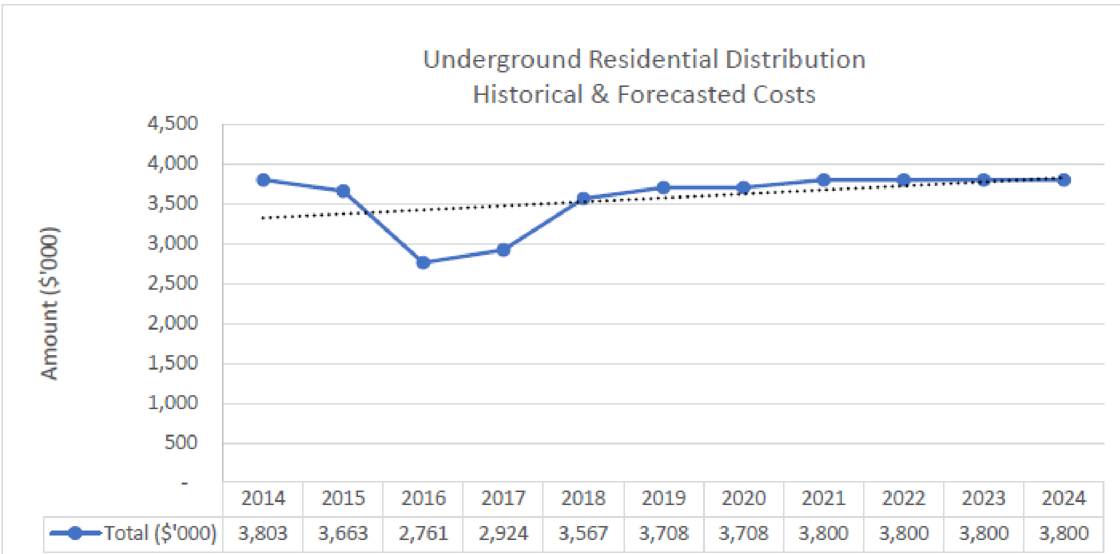
The forecasted amount for Underground System Expansion to Supply New Developments is $170,000. This project is classified as a System Service (not System Access) project to supply general load growth in downtown Kitchener. Majority of the total project costs ($1.0M) is budgeted for Stage 1 of a new underground feeder that is required because of the anticipated increase in demand associated with the proposed developments in downtown Kitchener. However, no individual customer(s) can be attributed as the trigger for the new feeder expansion.

The estimated amount for contributed capital is based on a 10% estimate of the total project cost for 2019. There are few projects anticipated for connection that will require expansion of the existing underground system.

2-VECC-9

Reference: Exhibit 2, PDF pg. 358

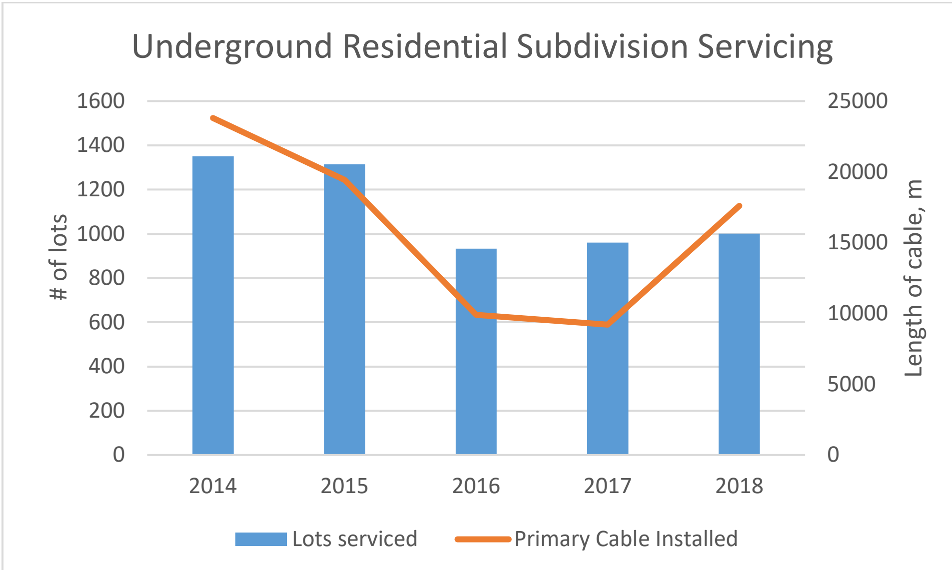
a) Please comment on the reason(s) for the decline in underground distribution capital expenditures in 2016 and 2017 (as shown on graph below).



The decline in underground distribution capital expenditures in 2016 and 2017 can be attributed to a combination of the following.

i. Type of services connected – 2016 and 2017 saw a number of stacked town-homes serviced which requires shorter runs of primary and secondary cable as can be seen in the figure below. Cost to supply and install primary cable has a significant impact on overall costs.

ii. Number of services connected – the number of services connected in 2016 and 2017 were also lower than previous years. This can be attributed to either a slow down in development activities or the timing of site plan approvals.


Underground Residential Subdivision Servicing
# of lots
1600
1400
1200
1000
800
600
400
200
0
25000
20000
15000
10000
5000
0
Length of cable, m
2014
2015
2016
2017
2018
Lots serviced
Primary Cable Installed

2-VECC-10

Reference: Exhibit 2, Appendix 2-3 Distribution System Plan, Table 3-16 page 125 (PDF 264)

a) Please provide the current average and median age of the vehicle fleet (without trailers) in 2018 and the expected average and median age at the end of 2020 and 2023.

Vehicle Fleet	Average Fleet Age (years)	Median Fleet Age (years)
December 31, 2018	8.2	8
December 31, 2020 (Projected)	7.9	8
December 31, 2023 (Projected)	7.7	8

2-VECC-11

Reference: Exhibit 2, Appendix 2-3, Distribution System Plan, page 48 (PDF 187)

a) Does KWHI collect SAIDI/SAIFI data for the different categories of defective equipment? If yes please provide the past 5 years annual data for: overhead equipment, underground equipment and station equipment (and any subcategories collected such as overhead transformers, overhead switches, poles and pole hardware).

As of April 2016, with the introduction of an outage management system (OMS), KWHI began collecting reliability data for different categories of defective equipment. The tables below show reliability data for defective equipment broken down into sub-categories for the period April 1, 2016 to December 31, 2018 excluding Major Events.

Defective Equipment Outages - April 2016 to December 2016

Secondary Cause	CHI	Customers Int.	SAIDI	SAIFI	CAIDI	# of Outages
Arrestor	402	288	0.0043	0.0031	1.3950	8
Breaker - Transformer	1,300	2,669	0.0138	0.0283	0.4872	6
Connector / Connections	72	37	0.0008	0.0004	1.9576	11
Cross arm	594	115	0.0063	0.0012	5.1630	1
Fuse	93	20	0.0010	0.0002	4.6657	3
Insulator	17,333	8,432	0.1848	0.0899	2.0566	6
Overhead transformer	352	223	0.0037	0.0024	1.5773	10
Overhead wire	7,521	3,074	0.0795	0.0325	2.4468	11
Padmount transformer	53	27	0.0006	0.0003	1.9574	1
Pole	97	16	0.0010	0.0002	6.0736	2
Pole fire	2,909	1,187	0.0311	0.0127	2.4504	4
Relay	2,738	9,270	0.0291	0.0986	0.2953	12
Service wire	81	66	0.0009	0.0007	1.2216	6
Submersible transformer	4,359	918	0.0463	0.0098	4.7515	49
Switch	9,805	12,401	0.1044	0.1319	0.7915	32
Underground cable	113	18	0.0012	0.0002	6.26	1
Underground transformer	301.017	108	0.0032	0.0011	2.7871	2
Total	**48,122**	**38,869**	**0.5120**	**0.4134**	**1.24**	**165**

Defective Equipment Outages – January 2017 - December 2017

Secondary Cause	CHI	Customers Int.	SAIDI	SAIFI	CAIDI	# of Outages
Arrestor	3,404	2,645	0.0355	0.0276	1.2869	5
Breaker - Transformer	74	42	0.0008	0.0004	1.7571	3
Bushing	13	3	0.0001	0.0000	4.2111	1
Connector / Connections	1,170	383	0.0123	0.0040	3.0583	29
Console	63	62	0.0007	0.0007	1.0187	2
Fuse	130	80	0.0014	0.0008	1.6144	8
Insulator	1,160	1,293	0.0121	0.0136	0.8912	7
Overhead transformer	201	44	0.0021	0.0005	4.5662	8
Overhead wire	200	90	0.0021	0.0009	2.2256	11
Padmount transformer	437	130	0.0046	0.0014	3.3592	6
Pole	327	49	0.0034	0.0005	6.6676	3
Pole fire	14	7	0.0001	0.0001	2.0357	2
Service wire	228	114	0.0024	0.0012	2.0050	13
Submersible transformer	5,714	1,030	0.0600	0.0108	5.5506	46
Switch	4,943	21,286	0.0517	0.2227	0.2322	38
Underground cable	267	137	0.0028	0.0014	1.94	6
Underground transformer	1048.4	340	0.0110	0.0036	3.0882	7
Total	**19,392**	**27,735**	**0.2031**	**0.2902**	**0.70**	**195**

Defective Equipment Outages – January 2018 - December 2018

Secondary Cause	CHI	Customers Int.	SAIDI	SAIFI	CAIDI	# of Outages
Arrestor	66	43	0.0007	0.0004	1.5264	2
Breaker - Transformer	59	30	0.0006	0.0003	1.9816	2
Connector / Connections	557	139	0.0057	0.0014	4.0052	22
Fuse	71	348	0.0007	0.0036	0.2053	9
Insulator	1,301	5,589	0.0134	0.0574	0.2335	8
Overhead transformer	318	469	0.0033	0.0048	0.6800	8
Overhead wire	280	1,139	0.0029	0.0117	0.2462	9
Padmount transformer	733	149	0.0076	0.0015	4.9193	9
Pole	4,065	3,437	0.0417	0.0353	1.1827	4
Pole fire	1,502	3,598	0.0155	0.0370	0.4199	6
Service wire	342	134	0.0035	0.0014	2.5477	16
Submersible transformer	5,027	1,027	0.0518	0.0106	4.8962	54
Switch	3,535	11,093	0.0363	0.1139	0.3184	21
Underground cable	5,395	6,409	0.0554	0.0658	0.8422	7
Underground transformer	347	133	0.0036	0.0014	2.6164	3
Total	**23,600**	**33,737**	**0.2427**	**0.3465**	**0.70**	**180**

b) If such data is not collected please explain what efforts are made to collect data on equipment failure related outages.

Prior to April 2016, when the OMS was commissioned, outages caused by defective equipment were not discretely recorded and therefore data isn't available for previous years.

2-VECC-12

Reference: EB-2013-0147 2013-2022 Estimated Expenditure & Exhibit 2, Appendix 2-3, Distribution Plan, Table 4-27, page 186 (PDF 325)

VECC has included a compendium to these interrogatories with two extracts from the evidence provided in KWHI's last cost of service application EB-2013-0147.

a) With respect to Appendix A please provide an assessment of the Utility's actual expenditures as compared to that forecast in the 2013-2022 Capital Expenditure Plan and as compared to Table 2.9.3.1-1.

The forecast expenditures in 2014 CoS application EB-2013-0147 for 2013 -2022 was based on 2013 dollars (no inflation) and was also based on the needs assessed at that time. The forecast prepared each year serves as a guide for planning purposes with KWHI updating the previous 5-year and 10-year forecast each year to meet current needs and changing priorities. A good example of this is the Region's LRT project that was initially forecasted to cost approximately $8.6M in 2013 but with more detail design information and multiple change in scope, the total project cost was over $26M. KWHI had to adjust its forecast each year and develop detail budgets to meet these changing priorities.

The table below shows a comparison between the actual capital expenditures from 2014 to 2018 and the planned capital expenditures for the same period as reported in KWHI's 2014 CoS application. The forecasted expenditures have been categorized into the four investment categories of System Access, System Renewal, System Service, and General Plant using best efforts. At the time of the 2014 application, investments were not categorized using this approach. The variance analysis in KWHI's 2019 Distribution System Plan section 4.3 is applicable for this table despite the planned amounts being different. That is, the drivers for the variances are mostly the same with the planned amounts being different.

Capital Projects Table with Comparison to 2014 CoS Planned Expenditures (EB-2013-0147 Appendix A) and Actual Expenditures for 2014 - 2018
(all numbers in '000s)

Projects	2014	2015	2016	2017	2018
System Access					
LRT Relocations	4,775	7,374	8,596	2,977	-
Roadway Relocations	1,744	2,822	2,357	2,339	1,720
Underground Residential Distribution	3,531	3,406	2,589	3,086	3,480
Commercial, Industrial & Apartment Services	412	1,142	734	1,109	1,161
Revenue Meters & Generation Connections	656	387	673	824	832
System Expansion - Customer Growth	8	12	895	592	120
Miscellaneous U/G Customer Connections	301	370	410	464	493
Miscellaneous O/H Customer Connections	51	108	578	278	198
Miscellaneous - Tx installed and Others	209	196	98	145	103
Sub-Total - Actuals	11,687	15,817	16,930	11,815	8,107
2014 CoS Planned Amount	10,296	9,305	7,160	7,245	7,245
%Variance (Actual vs Plan)	13.5%	70.0%	136.5%	63.1%	11.9%
System Renewal					
TS and DS Renewal	1,669	600	1,002	1,011	702
Replacement of Pole Line Assets	1,804	907	1,570	2,382	3,017
Voltage Conversion	-	-	-	162	1,175
Replacement of Primary Cables and Conduits	195	336	486	436	965
Rebuild Transformer Vaults & Pull Boxes	-	-	-	-	62
Network Transformer Replacement	96	167	183	296	364
Distribution Transformer Installation and Replacement	966	1,168	1,225	964	1,210
Miscellaneous U/G plant replacements	91	130	134	98	184
Miscellaneous O/H plant replacements	-	14	17	30	50
Sub-Total - Actuals	4,821	3,322	4,616	5,377	7,728
2014 CoS Planned Amount	5,970	6,070	8,755	9,405	9,385
%Variance (Actual vs Plan)	-19.2%	-45.3%	-47.3%	-42.8%	-17.7%
System Service					
System Expansion to Supply New Developments - TS	-	(835)	-	-	-
System Expansion to Supply New Developments - O/H	720	506	579	560	601
System Expansion to Supply New Developments - U/G	406	613	865	355	487
Innovation and Reliability	211	110	425	503	377
Voltage Conversion - Reliability/Flexibility	168	389	484	-	-
Miscellaneous	40	56	67	39	5
Sub-Total - Actuals	1,545	839	2,420	1,458	1,470
2014 CoS Planned Amount	1,520	1,800	1,925	1,925	1,925
%Variance (Actual vs Plan)	1.6%	-53.4%	25.7%	-24.3%	-23.6%
General Plant					
Land & Buildings	725	273	255	1,141	750
Office Equipment	58	64	37	53	109
IT/OT Systems	471	697	801	593	1,165
Vehicles	862	661	860	871	875
Tools & Equipment	164	164	141	148	131
Sub-Total - Actuals	2,280	1,859	2,093	2,807	3,029
2014 CoS Planned Amount	3,150	2,095	2,120	2,220	2,220
%Variance (Actual vs Plan)	-27.6%	-11.3%	-1.3%	26.4%	36.5%
Total	**20,333**	**21,836**	**26,058**	**21,456**	**20,334**
2014 CoS Planned Amount	**20,936**	**19,270**	**19,960**	**20,795**	**20,775**
%Variance	**-2.9%**	**13.3%**	**30.6%**	**3.2%**	**-2.1%**

2013-2022 CAPITAL EXPENDITURES FORECAST

ESTIMATED EXPENDITURES (x $1000) (in 2013 dollars - no inflation)

DESCRIPTION	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
BUILDINGS AND LAND										
301 Victoria St. S. Expansion	1,147.0									
Gas Tank Replacement & Paving		350.0								
Land Acquisition		1,000.0								
Subtotal	1,147.0	1,350.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
TRANSFORMATION FACILITIES										
Misc Transformer Station Upgrades & Modifications	221.2	87.0	200.0	400.0	300.0	500.0	500.0	500.0	500.0	500.0
#9TS Spare Transformer	513.9									
T99 Transformer Rewind	1,095.6									
P&C and Switchgear Upgrades at Various Stations	1,035.1	921.0	900.0	1,700.0	2,200.0	1,800.0	700.0	700.0		
#5TS Replace Power Transformers								800.0	1,000.0	4,500.0
Subtotal	2,865.8	1,008.0	1,100.0	2,100.0	2,500.0	2,300.0	1,200.0	2,000.0	1,500.0	5,000.0
POLE LINES										
Misc Overhead Distribution	775.0	700.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
System Expansion to Supply New Development	350.0	300.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
Relocations Due to Roadway Modification Projects	1,155.0	1,200.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
Replacement of Pole Line Assets Due to Age/Condition	2,216.2	2,575.0	2,500.0	3,500.0	3,500.0	3,500.0	3,500.0	3,500.0	3,500.0	3,500.0
27.6 kV Voltage Conversion	430.0	550.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
Innovation and Reliability		250.0	350.0	450.0	450.0	450.0	450.0	450.0	450.0	450.0
Subtotal	4,926.2	5,575.0	5,300.0	6,400.0	6,400.0	6,400.0	6,400.0	6,400.0	6,400.0	6,400.0
UNDERGROUND DUCTS AND CABLES										
Misc Underground Distribution	450.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
System Expansion to Supply New Development	300.0	200.0	250.0	275.0	275.0	275.0	275.0	275.0	275.0	275.0
Installation of New Residential UG Services	450.0	450.0	475.0	475.0	500.0	500.0	500.0	500.0	500.0	500.0
Installation of Commercial, Industrial & Apartment Services	350.0	350.0	375.0	375.0	400.0	400.0	400.0	400.0	400.0	400.0
Installation of New Underground Residential Distribution	2,200.0	2,250.0	2,500.0	2,800.0	2,800.0	2,800.0	2,800.0	2,800.0	2,800.0	2,800.0
Relocations Due to Roadway Modifications	3,443.7	3,944.1	2,650.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
Replacement of Primary Cables Due to Age/Condition	250.0	250.0	250.0	500.0	750.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Rebuild Transformer Vaults				250.0	250.0	250.0	250.0	250.0	250.0	250.0
27.6 kV Voltage Conversion	50.0	220.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Subtotal	7,493.7	8,164.1	7,100.0	5,425.0	5,725.0	5,975.0	5,975.0	5,975.0	5,975.0	5,975.0
DISTRIBUTION TRANSFORMERS										
Installation & Replacement of Distribution Transformers	725.0	800.0	775.0	925.0	925.0	925.0	925.0	925.0	925.0	925.0
Installation of New URD Transformers	485.0	475.0	525.0	590.0	590.0	590.0	590.0	590.0	590.0	590.0
Overhead Transformer Purchases	444.6	444.6	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
Commercial, Industrial & Apartment Transformer Purchases	378.5	358.0	400.0	400.0	435.0	435.0	435.0	435.0	435.0	435.0
URD Transformer Purchases	688.6	657.1	730.0	820.0	820.0	820.0	820.0	820.0	820.0	820.0
Network Transformer Purchases	341.2	192.1	195.0	230.0	230.0	160.0	230.0	230.0	230.0	230.0
Subtotal	3,062.9	2,926.8	3,125.0	3,465.0	3,500.0	3,430.0	3,500.0	3,500.0	3,500.0	3,500.0
REVENUE METERS	690.0	612.0	550.0	450.0	450.0	450.0	450.0	450.0	450.0	450.0
OFFICE EQUIPMENT	90.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
INFORMATION TECHNOLOGY	739.0	720.0	750.0	750.0	800.0	800.0	800.0	800.0	800.0	800.0
VEHICLES	890.0	920.0	925.0	950.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
TOOLS & EQUIPMENT	88.4	90.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
TOTAL	21,993.0	21,435.9	19,270.0	19,960.0	20,795.0	20,775.0	19,745.0	20,545.0	20,045.0	23,545.0

The following is a high-level variance summary between the planned investments in the 2014 CoS application ***EB-2013-0147 for 2013 -2022*** and the actual expenditures between 2014 and 2018.

2014 Variance Summary

The 2014 planned amount used in the DSP is the same as the 2014 planned amount in the table below which represents the final capital expenditure amount approved by the OEB in 2014 CoS application. Therefore, the variance analysis is the same as outlined in the DSP.

2015 Variance Summary

In 2015, the total variance is 13.3%, with *System Access* (+70%) being predominantly responsible for the large variance. LRT and road relocation projects accounted for $10.2M in expenditures compared to the budgeted amount of $3.25M.

System Renewal had a negative variance (-45.3%) since several pole line rebuild and transformer stations renewal projects that were planned for in 2015 were deferred to accommodate LRT-related work.

System Service had a negative variance (-53.4%) due to a one-time credit given back to KWHI by HONI for Detweiler TS bypass cost.

General Plant had a negative variance (-53.4%) Vehicles expenditures were $264K less than budgeted because of timing in the delivery of vehicles procured during the year.

2016 Variance Summary

In 2016, the total variance is 30.6%. The variance is primarily due to the impact of the LRT project changing in scope resulting in *System Access* (+136.5%) exceeding the forecasted amount by over 100%. LRT and road relocation projects accounted for $10.9M in actual expenditures compared to the budgeted amount of $0.75M.

System Renewal had a negative variance (-47.3%) since several pole line rebuild and transformer stations renewal projects that were anticipated in EB-2013-0147 for 2016 were deferred to accommodate LRT-related work.

System Service had a positive variance (+25.7%) due to System Expansion to Supply New U/G Developments were greater than anticipated ($865K actual vs $275K forecasted)

General Plant actual expenditures were in-line with the forecasted amount and only had a small negative variance (-1.3%).

2017 Variance Summary

In 2017, the total variance between the forecast in EB-2013-0147 for 2013 -2022 and the actual expenditures is +3.2%, which is well within a 10% variance. While there were larger variations in individual investment categories, the overall variance was very small. *System Access* had a large positive variance (+63.5%) which was offset by System Renewal large negative variance (-42.8%). LRT and road relocation projects were responsible for the large variance in System Access. $5.3M in actual cost vs the budgeted amount of $0.75M.

System Renewal had a negative variance (-42.8%) since several pole line rebuild and transformer stations renewal projects that were anticipated in EB-2013-0147 for 2017 were deferred to accommodate LRT-related work. Also, the volume of underground primary cable replacement planned for replacement in 2017 did not occur.

System Service had a negative variance (-24.3%) due to Voltage Conversion projects that were initially forecasted as System Service ($500K) being reclassified as System Renewal in 2017.

General Plant had a positive variance (+26.4%) because of the actual expenditures ($$1.1M) for Buildings and Lands exceeding the planned amount ($250K). The increase in actual expenditures was to facilitate the replacement of insulation and cladding at the main office building at 301 Victoria St. S.

<u>2018 Variance Summary</u>

In 2018, the total variance between the forecast in EB-2013-0147 for 2013 -2022 and the actual expenditures is -2.1%, which is well within a 10% variance. While there were larger variations in individual investment categories, the overall variance was very small.

System Access had positive variance of +11.9% which was primarily due to road relocation projects with actual cost of $1.72M vs the budgeted amount of $0.75M.

System Renewal had a negative variance of -17.7% due primarily to the reduction in actual expenditures for transformer station expenditures caused by a deferral of P&C and Switchgear Upgrades at Various Stations.

System Service had a negative variance (-17.7%) due to Voltage Conversion projects that were initially forecasted as System Service ($500K) being reclassified as System Renewal in 2017.

General Plant had a positive variance (+36.5%) because of the actual expenditures ($0.75M) for Buildings and Lands exceeding the planned amount ($250K). The increase in actual expenditures was to facilitate the renovation of the control room and IT department. There was also higher than anticipated expenditures associated with IT infrastructure due to the replacement of the core physical servers that were at end of life.

b) The Plan amounts in Appendix A appear to be different than the planned amounts shown as the planned amounts in Table 4-27 of the current Distribution Plan. Please explain why the variance tracked in Table 4-27 is not from the planned presented in EB-2013-0147.

c) With respect to Appendix B (Stations 10 Year Plan) please explain whether the station projects estimated to be completed by 2019 in the "0147 Plan" have been completed and whether the remainder (2020-2022) of that plan is still current/relevant.

The following projects identified in the Stations' Major Equipment 10 Year Plan 2013-2022 have been completed:

- #4TS – Install Arc Resistance on Switchgear
- #9TS – Spare Transformer – Manufacture and Install
- #7TS – T14 Failure
  - Move & Install T99 as a New T14
  - Repair Failed T14 & Install as T99
- #5TS – Building Addition & P&C Replacement
- Upgrade SCADA TS Fibre Loop Communications – 1TS, 3TS, 4TS, 5TS, 6TS, 7TS & 8TS.

The following projects, originally planned for completion by 2019, have not yet been completed but are planned to start in 2019 or later:

- #5TS – Install Arc Resistance on Switchgear
- #6TS – P&C Replacement
- Replace 17 SF6 Breakers at 3TS, 5TS & 6TS
- #7TS – P&C Replacement

The following are the remainder of the projects on the 2013-2022 plan and they are all still planned for completion in the attached Transformation Facilities' Major Equipment 10 Year Plan 2019-2028 (see DSP Appendix O - 10-Year Transformer & Distribution Station Renewal Plan):

- #1TS P&C Replacement
- #7TS – Replace 13 SF6 Breakers
- #5TS – Replace Power Transformers

Exhibit 3 – Operating Revenue

3-VECC-13

Reference: Exhibit 3, page 5 (lines 7-8) and page 6 (lines 23-26)

Load Forecast Model, Power Tab and Energy Tab

a. Do the IESO purchased power values used in the Load Forecast Model include purchases related to the GS>50 customer that is a wholesale market participant? If not, please reconcile this with the fact that, in the Energy Tab, the wholesale market participant customer is included in the allocation of the forecast purchased for 2019 and 2020.

The IESO Purchased column does not include WMP purchases. Confirmed – the amount should be distributed to other classes see EB-2019-0049_KWHI_IR_Load Forecast Model_3-VECC-13_20190731.

b. Do the IESO purchased power values used in the Load Forecast Model include purchases related to the embedded distributor? If yes, please reconcile this with the fact that, in the Energy Tab, the embedded distributor is not included in the allocation of the forecast purchased for 2019 and 2020.

The IESO purchased column does not include the Embedded Distributor purchases.

c. Please indicate the timing of the installation of LED lighting for purposes of street lighting in KWHI's service area.

The LED lighting conversion was completed in December 2017.

d. How was kWh adjustment related to the installation of LED lighting determined?

KWHI used load data from a third-party laboratory to verify the energy usage of the LED luminaires used by the Region of Waterloo, Wilmot Township and the City of Kitchener. Furthermore, KWHI also conducted a sample field verification of different size LED luminaires used in the City of Kitchener to verify laboratory results that indicated the consumption would be 50% less than traditional streetlights.

e. In adjusting the purchase power values, were the values for the consumption loss attributed to either the three large use customers or LED street lighting adjusted for losses?

These amounts were not adjusted for losses.

f. Does the calculation of the loss factor used in converting the forecast power purchased to billed load account for the various adjustments made to the historical purchased power values for purposes of the developing the regression model? If not, what is the impact on the billed energy forecast?

That loss factor should have been adjusted to be the same loss factor as determined in Chapter 2 Appendices 2-R. This has been corrected in the most up to date version of KWHI's load forecast EB-2019-0049_KWHI_IR_Load Forecast Model_Interrogatories_20190731.

3-VECC-14

Reference: Exhibit 3, page 10 (lines 5-15) and page 11 (Table 3.1.7-2)

Load Forecast Model, CDM Tab

Preamble: The CDM Tab contains the following values for CDM

A	B	C	D	E	F	G
	Total Annual CDM Results	Total Annual CDM Results	Full year Increase over	Half year pattern		
2005	292,583	292,583	292,583	146,292	146,292	1,876
2006	11,429,858	10,724,827	10,432,244	5,508,705	5,238,628	67,162
2007	30,126,928	21,463,789	10,738,962	16,094,308	6,152,918	78,884
2008	34,400,975	27,058,909	5,595,120	24,261,349	2,960,726	37,958
2009	47,381,961	36,655,515	9,596,606	31,857,212	5,090,633	65,265
2010	54,664,487	39,643,598	2,988,083	38,149,557	1,984,886	25,447
2011	65,677,230	50,620,380	10,976,782	45,131,989	5,302,914	67,986
2012	71,029,722	56,622,172	6,001,792	53,621,276	4,002,206	51,310
2013	75,626,821	61,309,444	4,687,273	58,965,808	1,958,050	25,103
2014	83,853,806	70,275,491	8,966,047	65,792,468	5,169,848	66,280
2015	102,523,021	90,753,702	20,478,211	80,514,597	10,347,642	132,662
2016	121,091,398	110,125,229	19,371,527	100,439,466	11,169,172	143,195
2017	157,976,515	147,697,956	37,572,727	128,911,593	19,021,289	243,863
2018	149,693,568	139,710,565	- 7,987,391	143,704,261	- 1,302,269	- 16,696
2019	142,835,737	135,825,138	- 3,885,427	137,767,852	- 4,834,489	- 61,981
2020	137,021,969	132,002,384	- 3,822,754	133,913,761	236,631	3,034
Total		1,130,781,685		1,064,780,493		

a. The columns included in Table 3.1.7-2 only include the years 2013 to 2020. Please provide a revised version of the table that also includes 2008 to 2012 in the columns (i.e., all of the historical years used in developing the regression model).

CDM Activity Variable Supporting Data

Program Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Third Tranche	13,901,639	14,769,006	14,630,348	14,630,348	14,282,990	9,108,721	9,108,721	8,889,479	8,889,479	8,433,284	7,106,535	7,106,535	7,106,535
2006	6,036,035	6,036,035	1,048,326	1,048,326	958,933	958,933	901,065	901,065	851,308	851,308	851,308	851,308	770,593
2007	3,111,482	3,016,918	3,016,918	3,016,608	2,920,674	2,920,742	2,920,674	1,036,730	900,764	577,413	577,413	577,413	577,413
2008	4,009,754	3,663,596	3,663,596	3,663,596	3,373,055	3,372,859	3,070,530	2,844,942	2,206,893	1,920,979	1,772,269	1,772,269	1,743,360
2009		9,169,960	7,890,852	7,890,852	7,887,707	7,796,526	7,491,580	7,041,836	6,832,205	5,280,326	3,555,175	2,950,717	864,117
2010			9,393,558	7,125,232	7,116,405	7,117,426	7,023,483	6,565,926	6,533,244	6,022,794	4,928,030	1,963,457	1,202,683
2011				13,238,663	13,133,318	13,123,211	12,936,022	12,318,158	11,872,233	11,206,434	11,199,433	10,960,078	10,531,707
2012				6,756	6,949,090	6,754,594	6,679,287	6,359,018	6,093,073	5,398,744	5,172,457	5,168,162	4,975,668
2013						10,156,432	9,881,775	8,950,597	8,751,966	8,052,439	7,902,937	7,889,636	7,876,805
2014							10,262,354	9,722,970	9,493,634	9,308,070	8,464,732	8,417,314	8,197,711
2015								26,122,981	26,071,643	26,001,608	26,015,673	26,003,647	25,991,840
2016									21,628,788	21,628,788	22,395,334	22,395,334	22,395,334
2017										43,015,770	39,769,271	39,769,271	39,768,618
2018											14,096,523	14,096,523	14,096,523
2019													
2020													
Total	27,058,909	36,655,515	39,643,598	50,620,380	56,622,172	61,309,444	70,275,491	90,753,702	110,125,229	147,697,956	153,807,088	149,921,661	146,098,907

b. Please provide the actual reports that support the net results set out in Column C of the CDM Tab. If the reports do not document the persisting savings through to 2020 each program year, please explain how the persisting values were determined.

See filed Excel:

EB-2019-0049_KWHI_IR_2011-2015 LDC CDM Program Results-20170117
EB-2019-0049_KWHI_IR_2015-Final-Verified-Annual-LDC-CDM-Program Results-20160630
EB-2019-0049_KWHI_IR_2016-Final-Verified-Annual-LDC-CDM-Program Results-20170630
EB-2019-0049_KWHI_IR_2017-Final-Verified-Annual-LDC-CDM-Program Results-20180629
EB-2019-0049_KWHI_IR_2018 Participation and Cost Report-20190415

c. It is noted that the regression was performed using 2009-2018 data. However no values for 2018 CDM program impacts were included. Please comment on how this omission will impact the regression analysis results and the ensuing purchased power forecast.

KWHI has filed an updated version of its load forecast with an updated variable for CDM that includes 2018 amounts, although they are unverified at this point in time.

See filed Excel EB-2019-0049_KWHI_IR_Load Forecast Model-IR_20170731.

d. Please re-estimate the regression equation using just 2009-2017 data and then provide: i) the resulting regression equation and statistics, ii) the resulting weather normalized forecast (i.e., similar to Table 3.1.10-4) and iii) the supporting excel model. (Note: Manual adjustment for CDM impacts should include the forecast persisting savings from 2018 CDM programs).

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.965168276
R Square	0.931549801
Adjusted R Square	0.926758288
Standard Error	3102037.521
Observations	108

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	7	1.30956E+16	1.8708E+15	194.4165919	2.8604E-55
Residual	100	9.62264E+14	9.62264E+12		
Total	107	1.40579E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-30428504.36	30258357.48	-1.005623137	0.317024049	-90460223.79	29603215.07	-90460223.79	29603215.07
Heating Degree Days	39117.22814	1717.493386	22.7757664	2.30709E-41	35709.77018	42524.6861	35709.77018	42524.6861
Cooling Degree Days	356799.6924	17303.85952	20.61965957	8.52544E-38	322469.328	391130.0569	322469.328	391130.0569
Number of Days in Month	3635196.647	430849.8089	8.437271112	2.58219E-13	2780402.897	4489990.396	2780402.897	4489990.396
Spring Fall Flag	-6020124.392	749915.3747	-8.027738322	1.98114E-12	-7507935.137	-4532313.647	-7507935.137	-4532313.647
Number of Peak Hours	80734.26744	20406.10263	3.956378585	0.000142356	40249.14102	121219.3939	40249.14102	121219.3939
CDM	-0.999707908	0.456907759	-2.18798628	0.030999453	-1.906199889	-0.093215927	-1.906199889	-0.093215927
Residential Customers	407.9799056	371.6799021	1.097664693	0.274986972	-329.4224341	1145.382245	-329.4224341	1145.382245

3-VECC-14d CDM Adjusted Normalized Weather Billed Forecast (GWh)							
Year	**Residential**	**GS<50 kW**	**GS>50 kW**	**Large User**	**Street Lighting**	**USL**	**Total**
Normalized Weather Billed Energy Forecast (GWh)							
2018 (Normalized)	680.5	238.8	834.7	33.4	7.5	4.0	1,798.9
2019 (Normalized)	650.6	223.5	781.4	34.2	7.4	4.1	1,701.2
2020 (Normalized)	666.2	225.3	764.1	35.1	7.3	4.2	1,702.2

See filed Excel EB-2019-0049_KWHI_IR_Load Forecast Model_3-VECC-14d_20190731.

3-VECC-15

Reference: Exhibit 3, pages 8 and 12

a. How did KWHI determine the explanatory variables used in the regression analysis?

KWHI tested several models and utilized the one with the best R-squared value and MAPE value that also resulted in consumption amounts that were reasonable in comparison to historic values and expected future amounts.

b. Were other economic/demographic activity variable considered besides Number of Residential customers? If yes, please indicate what they were and why they were rejected.

See filed Excel:

EB-2019-0049_KWHI_IR_Load Forecast Model-3-Staff-27a_20190731 and

EB-2019-0049_KWHI_IR_Load Forecast Model-3-Staff-27b_20190731.

Employment did not provide substantially different results with or without the variable. Ontario GDP provided consumption results that were unrealistically low.

c. It is noted that neither the CDM nor the Residential Customers variable are statistically significant. Given these results, please explain why they were retained as explanatory variables.

During the process of testing the regression analysis, many different variables and times periods are tested to arrive to what KWHI deemed the best R-Squared and MAPE values. KWHI's rational behind selecting or dropping certain variables involves a "no-harm" rational. In other words, if a variable is justified and does not worsen the results, it is generally kept as one of the regression variables. In this case, the Residential Customers only slightly improved the R-Square, however, the utility still opted to keep them as part of the regression analysis.

d. Please re-estimate the regression equation excluding both the CDM and Residential Customers variable and provide: i) the resulting regression equation and statistics, ii) the resulting weather normalized forecast (i.e., similar to Table 3.1.10-4) and iii) the supporting excel model.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.957509236
R Square	0.916823936
Adjusted R Square	0.913175863
Standard Error	3387100.37
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	5	1.44161E+16	2.88323E+15	251.3173239	8.10311E-60
Residual	114	1.30786E+15	1.14724E+13		
Total	119	1.5724E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-739518.9661	12513775.16	-0.059096392	0.952978801	-25529211.18	24050173.25	-25529211.18	24050173.25
Heating Degree Days	39691.28121	1800.070954	22.0498426	6.28479E-43	36125.35452	43257.20791	36125.35452	43257.20791
Cooling Degree Days	372345.0897	17827.61593	20.88585995	9.01611E-41	337028.7198	407661.4595	337028.7198	407661.4595
Number of Days in Month	3595475.375	444404.7471	8.090542235	7.13005E-13	2715112.994	4475837.757	2715112.994	4475837.757
Spring Fall Flag	-5792739.848	774942.0163	-7.475062297	1.70853E-11	-7327894.014	-4257585.682	-7327894.014	-4257585.682
Number of Peak Hours	76035.84171	20873.24507	3.64274177	0.000407389	34686.10398	117385.5794	34686.10398	117385.5794

Interrogatory 3-VECC-15 d CDM Adjusted Normalized Weather Billed Forecast (GWh)

Year	Residential	GS<50 kW	GS>50 kW	Large User	Street Lighting	USL	Total
Normalized Weather Billed Energy Forecast (GWh)							
2019 (Normalized)	668.0	233.1	803.4	34.2	7.4	4.1	1,750.2
2020 (Normalized)	679.0	233.3	782.7	35.1	7.3	4.2	1,741.6

See filed Excel EB-2019-0049_KWHI_IR_Load Forecast Model_3-VECC-15d_20190731.

e. Please provide an alternative regression model and load forecast where: i) the explanatory variable is the purchased power values used in the current Application plus the CDM variable for the month, ii) the explanatory variables are the same as those in the current Application – excluding CDM and iii) the regression analysis uses 2009-2017 historical data. As part of the response please provide i) the resulting regression equation and statistics, ii) the resulting weather normalized forecast (i.e., similar to Table 3.1.10-4) and iii) the supporting excel model.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.962693221
R Square	0.926778237
Adjusted R Square	0.92242843
Standard Error	3369318.024
Observations	108

ANOVA

	df	SS	MS	F	Significance F
Regression	6	1.45125E+16	2.41874E+15	213.0618876	5.37712E-55
Residual	101	1.14658E+15	1.13523E+13		
Total	107	1.5659E+16			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	85682546.04	15804804.42	5.421297457	4.04647E-07	54330065.51	117035026.6	54330065.51	117035026.6
Heating Degree Days	39931.30289	1854.505175	21.53205255	1.5659E-39	36252.46348	43610.1423	36252.46348	43610.1423
Cooling Degree Days	364085.5591	18707.63	19.46187514	5.95967E-36	326974.6535	401196.4647	326974.6535	401196.4647
Number of Days in Month	3583855.026	467799.5784	7.661090756	1.15203E-11	2655866.499	4511843.552	2655866.499	4511843.552
Spring Fall Flag	-5866989.554	813643.1705	-7.210764826	1.04047E-10	-7481038.737	-4252940.372	-7481038.737	-4252940.372
Number of Peak Hours	83597.53238	22152.95765	3.773651073	0.000271584	39652.02349	127543.0413	39652.02349	127543.0413
Residential Customers	-1162.00825	105.6668413	-10.99690533	5.77058E-19	-1371.622839	-952.3936614	-1371.622839	-952.3936614

Interrogatory 3-VECC-15e CDM Adjusted Normalized Weather Billed Forecast (GWh)

Year	Residential	GS<50 kW	GS>50 kW	Large User	Street Lighting	USL	Total
Normalized Weather Billed Energy Forecast (GWh)							
2019 (Normalized)	587.1	207.0	753.9	34.2	7.4	4.1	1,593.7
2020 (Normalized)	589.8	207.4	738.3	35.1	7.3	4.2	1,582.1

See filed Excel EB-2019-0049_KWHI_IR_Load Forecast Model_3-VECC-15e_20190731.

3-VECC-16

Reference: Exhibit 3, pages 12-14

Load Forecast Model, Customer Tab

Preamble: The Customer Tab contains the following:

Average Number of Customers or Connections											
	Residential	GS<50 kW	GS>50 kW	WMP	GS>50 kW CI A	Large User	Streetlights	USL	Subtotal	Embedded Distributor	Total
Growth Rate in Customer Numbers											
2009	1.0146	1.0145	0.9911			0.7500	1.0191	0.9963		1.0000	
2010	1.0164	1.0106	0.9841			0.3333	1.0148	0.9927		1.0000	
2011	1.0162	1.0121	0.9858			2.0000	0.9962	1.0370		1.0000	
2012	1.0157	1.0142	0.9713			1.0000	1.0032	1.0330		1.0000	
2013	1.0112	1.0055	0.9979	1.0000	1.0000	1.5000	0.9860	0.9709		1.0000	
2014	1.0121	1.0074	0.9937	1.0000	1.0000	0.6667	1.0419	1.0394		1.0000	
2015	1.0151	1.0067	0.9947	1.0000	1.0000	0.5000	1.0130	1.0163		1.0000	
2016	1.0171	1.0063	1.0011	1.0000	1.0000	1.0000	1.0098	0.9723		1.0000	
2017	1.0181	1.0116	0.9679	1.0000	27.000	1.0000	1.0260	1.0228		1.0000	
2018	1.0155	1.0059	1.0066	1.2500	1.2593	1.0000	0.9823	1.0507		1.0000	
Used	1.0140	1.0095	0.9936	1.0000	1.0000	0.8705	1.0091	1.0128		1.0000	
Geomean	1.0152	1.0095	0.9936	1.0379	1.7999	0.8705	1.0091	1.0128		1.0000	

a. Are the historic customer/connection counts use average annual values, mid-year values or year-end values?

It is the average annual values.

b. Please provide the customer/connection counts by class as of most recent month available.

Average Number of Customers or Connections											
	Residential	GS<50 kW	GS>50 kW	WMP	GS>50 kW CI A	Large User	Streetlights	USL	Subtotal	Embedded Distributor	Total
2008	75,154	7,265	1,014			4	1,522	820	85,779	1	85,780
2009	76,255	7,370	1,005			3	1,551	817	87,001	1	87,002
2010	77,506	7,448	989			1	1,574	811	88,329	1	88,330
2011	78,761	7,538	975			2	1,568	841	89,685	1	89,686
2012	79,997	7,645	947	4	1	2	1,573	869	91,038	1	91,039
2013	80,893	7,687	945	4	1	3	1,551	844	91,928	1	91,929
2014	81,868	7,744	939	4	1	2	1,616	877	93,051	1	93,052
2015	83,106	7,796	934	4	1	1	1,637	891	94,370	1	94,371
2016	84,530	7,845	935	4	1	1	1,653	866	95,835	1	95,836
2017	86,064	7,936	905	4	27	1	1,696	886	97,519	1	97,520
2018	87,395	7,983	911	5	34	1	1,666	931	98,926	1	98,927
2019	88,619	8,059	905	5	34	1	1,681	943	100,247	1	100,248
2020	89,860	8,136	899	5	34	1	1,696	955	101,586	1	101,587
	Actuals (not Average) as at June 30, 2019										
	88,154	8,082	912	5	34	1	1,681	929	99,798		99,798

c. The Application states that KWHI used a growth rate equal to the geometric mean for all classes except Residential. However, in the Customer Tab a different approach also appears to have been used for the GS>50 class. Please reconcile.

The geometric mean was used for the GS>50 class for growth. KWHI has no expectation of adding more wholesale market participants or Class A customers. Additionally, if there were expectations of more/less customers, it would be a transfer of customer numbers within the same rate class not affecting overall customer numbers.

d. Please re-calculate the forecast number of Residential and GS<50 customers based on the following approach: i) remove the added load transfer customers from the historic data, ii) calculate the resulting geomean growth rate for each class including 2018 data, iii) forecast the 2019 and 2020 counts by applying the geomean value to the 2018 value (excluding the load transfer customers and then adding back in the load transfer customers.

Average Number of Customers or Connections											
	Residential	GS<50 kW	GS>50 kW	WMP	GS>50 kW Cl A	Large User	Streetlights	USL	Subtotal	Embedded Distributor	Total
2015	83,106	7,796	934	4	1	1	1,637	891	94,370	1	94,371
2016	84,530	7,845	935	4	1	1	1,653	866	95,835	1	95,836
2017	86,009	7,924	905	4	27	1	1,696	886	97,452	1	97,453
2018	87,340	7,971	911	5	34	1	1,666	931	98,859	1	98,860
2019	88,714	8,057	905	5	34	1	1,681	943	100,340	1	100,341
2020	90,109	8,144	899	5	34	1	1,696	955	101,843	1	101,844
Growth Rate in Customer Numbers											
2015	1.0151	1.0067	0.9947	1.0000	1.0000	0.5000	1.0130	1.0163		1.0000	
2016	1.0171	1.0063	1.0011	1.0000	1.0000	1.0000	1.0098	0.9723		1.0000	
2017	1.0175	1.0101	0.9679	1.0000	27.000	1.0000	1.0260	1.0228		1.0000	
2018	1.0155	1.0059	1.0066	1.2500	1.2593	1.0000	0.9823	1.0507		1.0000	
Used	1.0151	1.0093	0.9936	1.0000	1.0000	0.8705	1.0091	1.0128		1.0000	
Geomean	1.0151	1.0093	0.9936	1.0379	1.7999	0.8705	1.0091	1.0128		1.0000	

3-VECC-17

Reference: Exhibit 3, pages 16 and 18-20

Load Forecast Model, CDM Tab

Load Forecast Model, Energy Tab

Preamble: The CDM Tab calculates the following manual adjustments for 2019 and 2020:

	Proposed Cost of Service Method						
	2015	2016	2017	2018	2019	2020	Total
	kWh						
2015	2,936,389	2,936,389	2,936,389	2,936,389	2,936,389	2,936,389	17,618,333
2016		3,523,667	3,523,667	3,523,667	3,523,667	3,523,667	17,618,333
2017			4,404,583	4,404,583	4,404,583	4,404,583	17,618,333
2018				5,872,778	5,872,778	5,872,778	17,618,333
2019					8,809,167	8,809,167	17,618,333
2020						17,618,333	17,618,333
					Apply 1/2 year rule		
					5,872,778	5,872,778	
					4,404,583	8,809,167	
						8,809,167	
					10,277,361	23,491,111	

The Energy Tab sets out the following allocation to customer classes:

		Residential	GS<50 kW	GS>50 kW	WMP	Class A	Large User	Streetlights	USL
CDM		Manual Adjustment to the Load Forecast from 2019 and 2020 Programs on a Net Level							
		5.00%	25.00%	70.00%					
2019	(10,277,361)	(513,868)	(2,569,340)	(7,194,153)	0	0	0	0	0
2020	(23,491,111)	(1,174,556)	(5,872,778)	(16,443,778)	0	0	0	0	0

a. Please provide a copy of KWHI's most recent 2015-2020 CDM Plan as approved by the IESO.

   See filed Excel EB-2019-0049_KWHI_IR_ 2015-2020 CDM Plan KWHI-InnPower

b. Are the 2018-2020 annualized CDM savings used in the CDM Tab based on KWHI's most recent CDM Plan? If not, why not and what is the basis for the values?

   No – see 3-Staff-33

c. Is the assignment of the CDM adjustment to customer classes in the Energy Tab based on KWHI's most recent CDM Plan? If not, why not and what is the basis for the values?

No. At the time of the filing of the Application, the split was based on most recent actuals (2017).

These values are updated in the current Load Forecast to be the projected splits for 2019 and 2020 programs. Note there has been a significant reduction in Residential programs offered.

d. Why is the full value of the 2018 savings included in the adjustment when actual 2018 load were used in the development of the load forecast model?

The load forecast has been updated with 2018 unverified amounts. See the Excel file EB-2019-0049_KWHI_IR_Load Forecast Model-IR_20190731.

3-VECC-18

Reference: Exhibit 3, pages 19-20

a. Is KWHI proposing to continue the LRAM Variance account for 2020?

   Yes, if it continues as Board Policy.

b. If yes, what is the proposed LRAMVA threshold for 2020 in terms of: i) total kWh, ii) kWh by customer class and iii) kW for those classes that are demand billed? As part of the response, please indicate how the values proposed were calculated.

2020 LRAM Threshold			
	Residential	**GS<50 kW**	**GS>50 kW**
kWh	243,297	3,162,859	20,923,530
kW where applicable		.	55,484

The values were calculated using the 2020 estimated savings and allocating 1% to the Residential Class, 13% to the GS<50 kW Class and 86% to the GS>50 kW Class

3-VECC-19

Reference: Exhibit 3, pages 18-20

Directive-CCF-Wind-down (http://www.ieso.ca/Sector-Participants/Conservation-Delivery-and-Tools/Interim-Framework)
Directive-Interim-Framework (http://www.ieso.ca/Sector-Participants/Conservation-Delivery-and-Tools/Interim-Framework)
Interim Framework CDM Plan – 20190524 (http://www.ieso.ca/Sector-Participants/Conservation-Delivery-and-Tools/Interim-Framework)

a. Please confirm that the CDM forecast through to 2020 in Table 3.2-1 is based on the Conservation First Framework implemented by the previous provincial government.

   Confirmed.

b. In March 2019 the current Minister of Energy issued directives i) discontinuing the Conservation First Framework and the Industrial Accelerator Program and ii) establishing a new Interim Framework. On June 5, 2019 the IESO published the new framework setting out both those programs that would be continued and those that would be discontinued. The IESO also released new program budgets and targets for 2019 and 2020. What impact will the revised framework (which only continues some of the of original Conservation First Framework's programs) have on the forecast CDM savings for 2019-2020 as set out in: i) KWHI's latest CDM Plan and ii) Table 3.2-1?

   Table 3.2-1, which is also known as Filing Appendix 2-I is being refiled at this time as a result of the new filing guidelines for 2020 filers that were issued on July 20, 2019. The filing requirements state that Appendix 2-I should only reflect projects KWHI has contracted for completion. KWHI has no insight into which programs its customers have signed up for in the new Interim Framework, or what savings will be delivered.

   KWHI latest CDM plan has been filed as part of the interrogatory process (see file EB-2019-0049_KWHI_IR_2015-2020 CDM Plan KWHI-InnPower). KWHI expects that it will deliver more CDM savings than its original target of 105GWh.

3-VECC-20

Reference: Exhibit 3, pages 34-35

a. Please explain the income reported with respect to Account #4245.

From the Accounting Policy Handbook:

4245 Government and Other Assistance Directly Credited to Income

This account shall include the deferred revenues arising from customer contributions that are amortized to income. Amounts recognized in Account 2440 are to be amortized to income over the useful life of the related property, plant and equipment or intangible asset to which the contribution were made by debiting Account 2440, Deferred Revenue, and crediting this account.

KWHI has followed the Board's guidance in its recording of these amounts.

b. Please provide the derivation of the 2020 Pole Rental Revenue ($850,440) and indicate how the number of attachments assumed in the calculation compares with the actual number of attachments in 2018.

2020	Quantity	Price	Total
Number of cable and strand attachments.	15,204	$ 43.63	$ 663,351
Number of cable and strand attachments. - tree trimming	5,570	2.77	$ 15,429
Number of clearance poles for service drops.	242	21.81	$ 5,278
Number of accessories WITHOUT existing attachments.	13	43.63	$ 567
Number of accessories WITH existing attachments.	89	1.92	$ 171
Number of 2nd party overlashes PRE 2005.	64	10.90	$ 698
Number of 2nd party overlashes POST 2005.	8	43.63	$ 349
Duct Rental	20,572	$ 8.00	$ 164,575
Total			**$ 850,417**

The same number of attachments in 2018 is used in the derivation on 2020 revenue.

Exhibit 4 – Operating Expenses

4-VECC-21

Reference: Exhibit 4, pages 23, Table 4.1.1-2

a) Are contributions for the LRT construction and other capital works are credited to operating costs or capital cost an as an offset to rate base?

Contributed capital for all capital, regardless of whether it is LRT or not, is treated as an offset to rate base.

b) Please explain the difference between a “capital contribution” and an “administrative offset”. Specifically who pays the latter and for what purpose?

A capital contribution is the amount of capital contributed by a customer for a portion of the constructed asset. It is a contra-asset account and carries a credit balance. It is amortized based on the service life of the asset.

Administration credits represent the 12% of total cost that is added to invoices for billable jobs. This is paid by the customer who requested the work. It is used to cover the portion of administrative expenses related to the project and is treated as a reduction to OM&A.

c) A review of Appendix 2-G “Detailed, Account by Account, OM&A Expense Table from EB-2013-0147 Exhibit 4, Tab 2, Schedule 8 shows no items identified as “administrative offset”. Please explain the different presentation in this Application.

Appendix 2-G in EB-2013-0147 presents OM&A by USoA account. This Application presents OM&A by program level. Administration credits in EB-2013-0147 were included in USoA accounts 5005 (77%) and 5615 (23%)

4-VECC-22

Reference: Exhibit 4, page 63 Table 4.4.3-1 and Appendix 2-K

a) Please amend Appendix 2-K to show for each year 2014 through 2020 the total amount of employee costs capitalized and expensed in each year.

Appendix 2-K
Employee Costs

	2014 Board Approved	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Test
Number of Employees (FTEs including Part-Time)								
Management (including executive)	34	34	31	30	29	28	30	31
Non-Management (union and non-union)	141	141	145	153	157	156	156	157
Total	**175**	**175**	**176**	**183**	**185**	**184**	**186**	**188**
Total Salary and Wages including ovetime and incentive pay								
Management (including executive)	$ 3,610,775	$ 3,734,214	$ 3,575,959	$ 3,633,300	$ 3,535,632	$ 3,499,556	$ 3,672,100	$ 3,736,799
Non-Management (union and non-union)	$ 10,817,928	$ 11,412,143	$ 11,795,569	$ 12,721,511	$ 12,802,464	$ 12,985,966	$ 13,309,825	$ 13,788,574
Total	**$ 14,428,703**	**$ 15,146,357**	**$ 15,371,528**	**$ 16,354,811**	**$ 16,338,096**	**$ 16,485,522**	**$ 16,981,925**	**$ 17,525,372**
Total Benefits (Current + Accrued)								
Management (including executive)	$ 859,641	$ 875,986	$ 845,597	$ 828,795	$ 813,172	$ 785,567	$ 839,982	$ 847,125
Non-Management (union and non-union)	$ 2,773,109	$ 2,753,539	$ 2,896,444	$ 3,087,435	$ 3,148,125	$ 3,343,268	$ 3,351,218	$ 3,472,675
Total	**$ 3,632,750**	**$ 3,629,526**	**$ 3,742,041**	**$ 3,916,231**	**$ 3,961,296**	**$ 4,128,835**	**$ 4,191,200**	**$ 4,319,800**
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$ 4,470,416	$ 4,610,200	$ 4,421,556	$ 4,462,096	$ 4,348,804	$ 4,285,123	$ 4,512,082	$ 4,583,924
Non-Management (union and non-union)	$ 13,591,037	$ 14,165,683	$ 14,692,014	$ 15,808,946	$ 15,950,589	$ 16,329,234	$ 16,661,043	$ 17,261,249
Total	**$ 18,061,453**	**$ 18,775,883**	**$ 19,113,570**	**$ 20,271,042**	**$ 20,299,392**	**$ 20,614,357**	**$ 21,173,125**	**$ 21,845,172**
Labour Capitalized		**6,748,816**	**7,815,459**	**8,515,232**	**8,035,347**	**7,091,653**	**8,351,280**	**8,964,069**
Labour Expensed		**12,027,067**	**$ 11,298,111**	**$ 11,755,810**	**$ 12,264,045**	**$ 13,522,704**	**$ 12,821,845**	**$ 12,881,103**

4-VECC-23

Reference: Exhibit 4, Table 4.4.3.1-2 Change in Headcount

a) KWHI explains that the current CIS requires significant resources for the specialized labour to maintain its aging COBOL code. Given this, please explain why the replacement of this system would not lead to a reduced need for IT personnel.

The burden of the aging CIS on KWHI's IT department has led to underdevelopment of the other important systems that KWHI uses and this must be rectified. For example, the JD Edwards system still requires development and has not been well supported by KWHI's IT staff.

In addition, the new CIS will still require support from KWHI's IT staff. While there will be a managed service agreement with a third party, KWHI's in-house IT staff will remain the first line of defense for the new CIS.

4-VECC-24

Reference: Exhibit 4, Section 4.2.3. page 21

a) Please explain the reason(s) for the decrease in spending on the outage management system.

In 2014, KWHI budgeted $80,000 in software maintenance (OM&A) costs for the proposed outage management system (OMS). This was based on the best information available at that time and budgetary estimate received from a potential vendor. Subsequently, an RFP process was undertaken to select a preferred OMS vendor and the actual software maintenance costs (approx. $20K) were significantly less than budgeted. The OMS went live in 2016.

4-VECC-25

Reference: Exhibit 4, Table 4.2.3-1, page 23

a) In what year and month did KWHI introduce monthly billing?

December 2015.

b) In KWHI previous cost of service rates proceeding - EB-2013-0147 - the Utility forecast an incremental increase in OM&A of $178,000 in 2013 and $164,000 in 2014 for the costs of monthly billing (Table 4-5, Exhibit 4, Tab 1, Schedule 2). Table 4.2.3-2 suggests a further incremental cost of $465,270. Is this latter cost an ongoing annual cost and is it in addition to those prior identified annual costs?

In KWHI's Decision for EB-2013-0147, KWHI received only $204,500 for incremental monthly billing, having been reduced by the Board's decision. The $465,270 is net of the $204,500. In other words, the increased costs of monthly billing and other increased collection activities as a result of monthly billing, such as disconnections and reminder notices, are really $669,770, of which $204,500 was recovered in 2014.

c) Please provide a breakdown of the annual incremental billing costs incurred since December 31, 2014.

Actual incremental cost to 2020 is $378K. See 4-EP-14 for calculation.

4-VECC-26

Reference: Exhibit 4, Table 4.2.3-3, page 24

a) Table 4.2.3-3 shows the forecast test year (2020) OEB assessment fees at $421,700. Appendix 2-M shows the 2018 actual costs to be $236,695 and 2019 forecast costs as $237,500. Why does KWHI believe it's OEB assessment costs will nearly double from 2019 to 2020?

In March 2016, the OEB announced an increase to its Cost Assessment fees. Excess fees were permitted to be placed in a deferral account to be disposed at the next rate application. In 2020, KWHI will no longer be deferring its Cost Assessment fees, resulting in the increase. See 4-Staff-40 b) for the calculation.

b) Please provide a breakdown of the $750,000 one-time costs incurred for this Application into the following categories:

- Legal costs
- External Consultant costs
- Internal staff costs
- Intervenor costs

For each category please show the amount of costs incurred to-date.

	Budget	to June 2019
Legal	150,000	14,012
External Consultant	428,000	243,389
Internal Staff	62,000	20,486
Intervenor	110,000	-
	750,000	277,886

c) Are any of the one-time regulatory costs included in the presentation of OM&A costs shown/included in Appendix 2-JA for 2018 ($19,417,969) or for 2019 ($20,167,300)?

There are no 2014 rebasing costs included in 2018 or 2019 as KWHI last rebased in 2014 under 3rd Generation IRM (using a four-year rebasing cycle) and the last of 2014's rebasing costs were fully amortized by year end 2017.

4-VECC-27

Reference: Exhibit 4, page 10

a) Please provide a breakdown of the $1.4 in incremental OM&A costs into the stated components: CIS/HR System Fees/OEB Cost Assessment/postage/ and other increases in HR Safety and additional maintenance expenses.

Incremental OM&A Above Inflation	
CIS	370,606
HR System fees	70,000
Cyber Security annual	180,000
HR & Safety	170,112
OEB Cost /Assessment Fees	198,383
Postage and Delivery	177,927
Maintenance	243,397
	1,410,424

4-VECC-28

Reference: Exhibit 4, Table 4.4.2.1-1, page 60

a) KWHI states it has negotiated wage increase for 2018-2021. Please update Table 4.4.2-1 to show the 2021 percentage increase.

The contract expires in March 2021. The 2.1% salary adjustment shown in Table 4.4.2.1-1 is for the period April 2020 – March 2021. KWHI does not have any negotiated increases after this date.

4-VECC-29

Reference: Exhibit 4, Table 4.10.1-1, page 91

a) Please explain why KWHI believes it will face an almost 7% increase in property taxes from that paid in 2018 when the past increases have been more modest at around 1.5% per year.

Past increases have been greater than 1.5% per year for property tax.

City of Kitchener property tax increases in the years 2017 and 2018 were 2.2% and 1.8% respectively.

Township of Wilmot increases to property tax in 2017 and 2018 were 2.4% and 3.5% respectively.

2019 property tax included in the rebasing budget was based on the 2018 forecast plus 1.4%.

2020 property tax included in the rebasing budget was based on the above 2019 rebasing figure plus 1.4%.

2018 FCST	2019 Bridge	2020 Test
424,800	430,800	436,900

If the methodology is changed to use the 2018 Actual with increases based on the past two-year historical increases, the results would be as follows:

	2018 Actual	2019 Bridge +% increase	2020 Test +% increase
City of Kitchener	367,543	376,000	384,600
Township of Wilmot	32,344	33,300	34,300
Proxy Taxes: OEFC	8,367	8,400	8,400
Total	**408,253**	**417,700**	**427,300**

The difference between the two methodologies is immaterial.

Comparing 2019 YTD actuals of $208,200 to 2019 YTD budget of $208,700 demonstrates that the budgeted amounts are accurate and reasonable.

4-VECC-30

Reference: Exhibit 4, Appendix 2-N & Exhibit 4, page 77

a) Please explain why street lighting maintenance fees (Kitchener and Wilmot) paid to KWHI have declined significantly since 2014 (367,960) to 2020 ($293,300)

The conversion of streetlights to LED lighting in 2016/2017/2018 by the Region of Waterloo and the City of Kitchener has resulted in a reduction in the maintenance services projected to be provided by KWHI to KESI. The streetlights are newer and will have less maintenance associated with them.

4-VECC-31

Reference: Exhibit 4,

a) Is KWHI a member of the Electricity Distributors Association? If yes please provide the fees paid to this association for the each of the years 2014 through 2020 (forecast).

Year	EDA Membership fees
2014	$74,600
2015	$77,100
2016	$77,900
2017	$78,700
2018	$80,300
2019	$81,900
2020	$86,900

4-VECC-32

Reference: Exhibit 4, page 45 & Appendix 2-JC

KWHI is proposing to increase its Overhead Maintenance program spending by about 400k in 2019 onwards as compared to the previous 5 years. At Exhibit 4 $132,300 of this is explained as an increase in the storm damage budget. Vegetation management is suggested as another area of incremental increase.

a) Please provide the vegetation management actuals and budget for the period 2014 through 2019.

Table 4-VECC-32

Tree Trimming	2014 Actual CGAAP	2015 Actual MIFRS	2016 Actual MIFRS	2017 Actual MIFRS	2018 Actual MIFRS	2019 Bridge MIFRS
Actual	743,731	842,913	758,620	679,077	720,250	398,679
Budget	840,000	764,300	734,900	784,300	905,000	789,900

* 2019 Actuals as of June 2019

b) Please identify any other significant incremental cost which is contributing to the rising cost in this category.

In addition to budgeting for incremental costs for vegetation management and storm damage repairs, KWHI budgeted to increase contractor spending on its Animal Proofing program beginning in 2019. Animal contacts are one of the of the top causes of unplanned outages each year.

4-VECC 33

Reference: Exhibit 4, pages 99-103

Preamble: It is noted that the LRAMVA claim is based on:

- Final 2016 Annual Verified Results Report – KWHI
- Final 2015 Annual Verified Results Report – KWHI
- 2011-2015 KWHI CDM Program Persistence Results

a) The Application states that the reports were filed in working Microsoft Excel format. However, the files do not appear on the OEB's website. Please provide.

See filed Excel:

EB-2019-0049_KWHI_IR_2011-2015 LDC CDM Program Results-20170117
EB-2019-0049_KWHI_IR_2015-Final-Verified-Annual-LDC-CDM-Program Results-20160630
EB-2019-0049_KWHI_IR_2016-Final-Verified-Annual-LDC-CDM-Program Results-20170630
EB-2019-0049_KWHI_IR_2017-Final-Verified-Annual-LDC-CDM-Program Results-20180629
EB-2019-0049_KWHI_IR_2018 Participation and Cost Report-20190415

b) Has KWHI received from the IESO its verified 2017 CDM Results report?
   i. If yes, please provide a copy and indicate if there were there any adjustments to the savings in 2015 or 2016 from 2015 and 2016 programs.

   Yes, See above

   There are adjustments to the savings in 2015 and 2016

   ii. If adjustments were made, please provide an update the LRAMVA Work Form and claim accordingly.

   The LRAMVA Work Form includes adjustments from the 2017 report.

Exhibit 5 – Cost of Capital

5-VECC-34

Reference: E5/pg. 3 & Appendix 2-OB

a) The Appendix 2-OB for 2020 does not match Table 5.1-1 Deemed capital structure (4.88% vs 4.13%). Please confirm for the purpose of rate calculations the figure of 4.13% for long-term debt is being used.

Appendix 2-OB has been changed to 4.13% for the year 2020.

b) Notwithstanding the Board's limit of 4.13% for affiliated debt for the purpose of rate calculation does KWH pay a rate higher (4.88%) to its debt holders?

Yes, KWHI currently pays its shareholders 4.88% on its affiliated debt. This was the deemed long-term interest rate established for 2014 rates and KWHI has paid interest on its long-term debt at 4.88% for the 2014-2019 rebasing period.

Exhibit 7 – Cost Allocation

7-VECC-35

Reference: Exhibit 7, page 3

a) Has KWHI had any discussions with Board Staff regarding initiatives the Board will undertake to “prescribe a method to weather normalize hour data”? If yes, please indicate what the outcome to date has been.

KWHI has not had any discussions with Board Staff regarding this matter.

7-VECC-36

Reference: Exhibit 7, pages 4

a) Please provide the analysis supporting the billing and collecting weighting factors set out in Table 7.1.3-2.

KWHI analyzed the cost to provide billing and collection activities for the past three years. Then KWHI took the 3-year average volume provided to each rate class and multiplied it by the cost to provide the activity. This provided a cost per customer. Setting the weighting for the Residential class as 1, the remaining class weightings were determined.

	Residential	GS <50	GS>50	Large Use >5MW	Street Light	Unmetered Scattered	Embedded Distributor
Activity	**3 year average volume**						
Paper Bills	876,630	83,868	8,641	0	64	143	12
epost Bills	71,345	4,496	1,275	0	0	0	0
e-Bills	69,583	5,366	1,102	12	16	20	0
Reminders	69,874	5,647	373	0	1	7	0
Notices	25,646	2,841	205	0	0	2	0
Collection Trips	540	26	0	0	0	0	0
Disconnections	1,059	69	1	0	0	0	0
Calls	60,443	6,161	974	0	3	8	0
Emails	24,980	2,546	402	0	1	3	0
Counter Visits	4,494	458	72	0	0	0	0
Site Visits	0	0	54	1	0	0	0
Rate Analysis	0	41	174	0	0	0	0
New Account Setup	16,235	947	66	0	1	1	0
Counter Payments	34,370	3,709	333	0	6	14	0
Cheque Payments	34,627	20,831	3,335	0	58	79	0
Electronic Payments	877,504	65,622	7,671	12	17	74	12
Cost per customer	**29**	**37**	**56**	**59**	**46**	**44**	**25**
Weighting	**1.0**	**1.3**	**2.0**	**2.0**	**1.6**	**1.5**	**0.9**

7-VECC-37

Reference: Exhibit 7, page 2
Cost Allocation Model, Tabs I7.1 and I7.2
Exhibit 3, page 21

a) Please explain why the customer counts used in Tab I7.1 don't match those in the load forecast.

Tab I7.1 shows Meter Capital. The customer counts did not match as meter counts were at a point in time (December 31, 2018). The filed Cost Allocation model has made the adjustment to have the customer counts equal the meter counts.

b) Who owns the meter associated with the embedded distributor?

The Embedded Distributor, Waterloo North Hydro Inc., owns, operates and maintains the wholesale revenue metering.

c) Please explain why the customer counts used in Tab I7.2 don't match those in the load forecast.

The customer counts were at a point in time. This has been adjusted on the filed Cost Allocation model dated 07312019.

Meter counts match Tab 7.1

d) Why are there no meter reading costs associated with the embedded distributor?

The meter reading costs are immaterial (approximately $160/yr). In addition, direct allocation of costs is used for the Embedded Distributor, therefore no allocation should be done for meter reading.

7-VECC-38

Reference: Exhibit 7, pages 5-6 and Appendix 7.2
Cost Allocation Model, Tab I3

a) With respect to the TS (owned by the Host), please confirm that costs set out in Columns 2 and 3 are the total costs related to all of KWHI's Transformer Stations.

In Appendix 2-Q, Columns 2 and 3 originally had the costs of all transformer stations for KWHI. These numbers have been adjusted as a result of 7-Staff -52.

b) Please reconcile the Total OM&A costs and the Original Asset Costs for TS (Owned by Host) set out in Appendix 2-Q (Columns 2 & 3) with the values reported by account in the Cost Allocation Model (i.e., for each of Columns 2 and 3 please demonstrate that the directly allocated values in the relevant the accounts in Tab I3 sum to the value reported).

OEB Account		Cost Allocation Model Tab I3	Appendix 2-Q (revised)
TS (Owned by Host)			
	1808	9,664,233	
	1815	68,392,529	
Total		**78,056,762**	**78,056,762**
	5012	412,000	
	5014	696,100	
	5112	634,200	
Total		**1,742,300**	**1,742,300**

c) With respect to the O/H and U/G facilities in Appendix 2-Q, please confirm that the costs set out in Columns 2 and 3 are the total costs related to all of KWHI's O/H and U/G facilities.

In Appendix 2-Q, Columns 2 and 3 originally had the costs of all O/H and U/G for KWHI. These numbers have been adjusted as a result of 7-Staff -52.

d) Please reconcile the Total OM&A costs and the Original Asset Costs for each of O/H and U/G facilities set out in Appendix 2-Q (Columns 2 & 3) with the values reported by account in the Cost Allocation Model (i.e., for each of Columns 2 and

3 please demonstrate that the directly allocated values in the relevant the accounts in Tab I3 sum to the value reported).

OEB Account		Cost Allocation Model Tab I3	Appendix 2-Q (revised)
Overhead			
	1830	53,694,577	
	1835	52,971,333	
Total		**106,665,910**	**106,665,910**
	5020	42,400	
	5025	135,300	
	5120	418,000	
	5125	1,549,900	
Total		**2,145,600**	**2,145,600**

OEB Account		Cost Allocation Model Tab I3	Appendix 2-Q (revised)
Underground			
	1840	46,058,892	
	1845	60,244,444	
Total		**106,303,336**	**106,303,336**
	5040	429,100	
	5045	372,000	
	5145	305,700	
	5150	708,100	
Total		**1,814,900**	**1,814,900**

e) Please provide the derivation of the $6,796 in General and Administrative Expenses directly allocated to the Embedded Distributor class.

The allocated administration costs include 12% of the total costs to cover general plant and administration costs.

7-VECC-39

Reference: Exhibit 7, pages 6-7 and Appendix 7.2
Cost Allocation Model, Tab I3
Tariff Schedule and Bill Impact Model – ED Bill Impacts

a) Please provide an alternative cost allocation model where cost are not directly allocated to the Embedded Distributor class based on Appendix 2-Q but rather the Embedded Distributor's load and customer count are included in the model's allocation of costs per Tab E3.

See file *EB-2019-0049_KWHI_IR_Cost Allocation 7-VECC-39.xlsx*.

KWHI used the original submitted Cost Allocation model and removed all direct allocations. KWHI then added the demand data on tab I8, meter reading costs on I7.2 and customer data on Tab I6.2.

The results show that the revenue requirement for the Embedded Distributor would increase to $226,066 up $32,164 from the originally filed Cost Allocation model.

b) It is noted that the bill impact calculations for the Embedded Distributor do not include any amounts in total bill impact for the cost of purchasing energy from the IESO. Please explain why this is the case and provide the total bill impact when the cost of energy is included.

The Embedded Distributor is a wholesale market participant and buys its energy directly from the IESO. The bill impact as presented is exactly as what would be billed by KWHI.

In the bill impact model, the cost of energy does not change; therefore, there is no change to the bill impact.

7-VECC-40

Reference: Exhibit 7, page 9

a) Please provide KWHI's rationale for the proposed changes to the revenue to cost ratios for the following customer classes: i) Residential, ii) GS>50; iii) Large Use, iv) USL and v) Embedded Distributor

Residential – the revenue to cost ratio is changed as a result of the changes to the other classes to ensure KWHI collects the revenue requirement

GS>50 – to bring the revenue to cost ratio down to Board approved levels

Large Use - to bring the revenue to cost ratio to unity

USL – to bring the revenue to cost ratio closer to unity

Embedded Distributor – to bring revenue to cost ratio up to Board approved levels

b) With respect to Table 7.3-1, would increasing the ratios for GS>50 and the Embedded Distributor to a value less than 98% offset the revenue loss from reducing the ratios for the GS<50 and Street Lighting classes to the levels proposed by KWHI? If yes, what would be the ratio?

KWHI reduced the ratios for the GS<50 and Streetlighting to bring the revenue to cost ratio within Board approved levels.

The revenue loss from reducing the GS<50 and the Streetlight rate class to the maximum Board approved revenue to cost ratio is:

	At maximum Board Approved revenue to cost ratio	At current revenue to cost ratio	Total revenue loss from reducing revenue to cost ratio
GS<50	6,195,147	6,254,854	59,707
Streetlight	334,895	358,532	23,637
TOTAL			83,344

The total revenue lost by moving to the maximum Board approved revenue to cost ratios is $83,344.

Yes, increasing the revenue to cost ratio to 97.4% for both the Embedded Distributor and the GS>50 rate classes would offset the revenue lost by reducing the revenue to cost ratio of the GS<50 and Streetlighting rate classes.

Exhibit 8 – Rate Design

8-VECC-41

Reference: Exhibit 8, page 8

a) How many KWHI customers were subject to standby charges in each of 2017 and 2018 and in what customer classes were they situated?

One customer in the Large User class.

b) For each year what was the additional revenue earned from standby charges?

See 7-Staff-54.

c) Do the historical load values used to calculate the kW/kWh ratios used in the Load Forecast model to derive the billing demand determinants include the kW that was subject to standby charges?

No.

d) If the response to part c) is no, how are the revenues from standby charges accounted for in the determination of the Base Revenue Requirement and the subsequent design of rates?

The amounts are not included as they are too immaterial to affect the calculation.

Exhibit 9 – Deferral and Variance Accounts

9-VECC-42

Reference: Exhibit 9, page 23

a) The Board established the Cost Assessment Variance sub-account 1508 in order to capture the impact of the change in its cost assessment methodology on the fees paid by LDCs. In booking amounts into this account please explain how KWHI differentiated between the variances that would have incurred in the normal course (under either the old or new methodology) and those amounts incurred due to the change in methodology.

The variance account was established to record material differences between OEB Cost Assessments built into rates and the new cost assessment model. KWHI followed this methodology to record variance amounts. KWHI recorded the amount of Cost Assessment included in rates as per EB-2013-0147 and the difference between the amount built into rates ($237,500) and the actual expense was placed into this deferral account. See Table 9.4.2.2-4.

If the variance account had not been set up, any increase in fees would have been expensed in the year it occurred. The cost driver would have occurred in 2016, rather than 2020.

9-VECC-43

Reference: Exhibit 9, page 9

a) Why is the balance for the Loss of Specific Customer variance account (1572) allocated to all rate classes rather than the large customer class, or otherwise the commercial class of customers?

   In EB-2013-0147 Settlement Agreement Issue 3.4, it was agreed that the revenues of one Large Use customer would be put in a variance account and refunded to customers through a future rate application.

   The refund methodology was not negotiated at that time so, in the absence of guidance, KWHI has refunded the balance to all customer classes.