INTERROGATORY RESPONSE - VECC-41

2.0-VECC-41

EXHIBIT REFERENCE:

Exhibit 2, Tab 4, Schedule 1, Updated

SUBJECT AREA: Rate Base

a) Please amend Table 1 (updated) to show the capital contributions by investment categories.

b) Please explain how capital contributions are forecast for the 2020 to 2025 period.

RESPONSE:

a) Table A below provides capital expenditures and capital contributions by investment categories.

Table A – Summary of 2021-2025 Capital Expenditures ($'000,000s)

Investment Category	2021	2022	2023	2024	2025	Average 2021-2025
Capital Expenditure						
System Access	$56.7	$41.0	$37.4	$34.5	$34.0	$40.7
System Renewal	$43.3	$44.0	$40.2	$39.4	$40.5	$41.5
System Service	$26.7	$28.3	$24.3	$25.2	$23.9	$25.7
General Plant	$32.0	$11.7	$7.6	$17.4	$16.9	$17.1
Total Expenditures	**$158.7**	**$125.0**	**$109.5**	**$116.4**	**$115.3**	**$125.0**
Capital Contributions						
System Access	$(38.9)	$(23.2)	$(19.7)	$(18.8)	$(18.8)	$(23.9)
System Renewal	$0	$0	$0	$0	$0	$0
System Service	$0	$0	$0	$0	$0	$0
General Plant	$(0.4)	$(0.3)	$(0.2)	$(0.4)	$(0.5)	$(0.4)
Total Contributions	**$(39.2)**	**$(23.5)**	**$(19.9)**	**$(19.2)**	**$(19.3)**	**$(24.2)**
TOTAL	**$119.5**	**$101.5**	**$89.6**	**$97.2**	**$96.0**	**$100.8**

b) System Access activities are driven by third parties and, as a result, capital contributions under System Access are forecasted using historical trending data by Program. Additionally, Hydro Ottawa coordinates with third parties to identify major projects expected to occur within the Test Years. The expected specific contributions are added to the historical program trending to arrive at the forecasted capital contribution amounts.

The capital contributions forecasted under the General Plant category represents forecasted Scientific Research & Experimental Development ("SR&ED") tax credits on certain technology-related projects.

INTERROGATORY RESPONSE - VECC-42

2.0-VECC-42

EXHIBIT REFERENCE:

Exhibit 2, Tab 4, Schedule 1, page 5, Updated

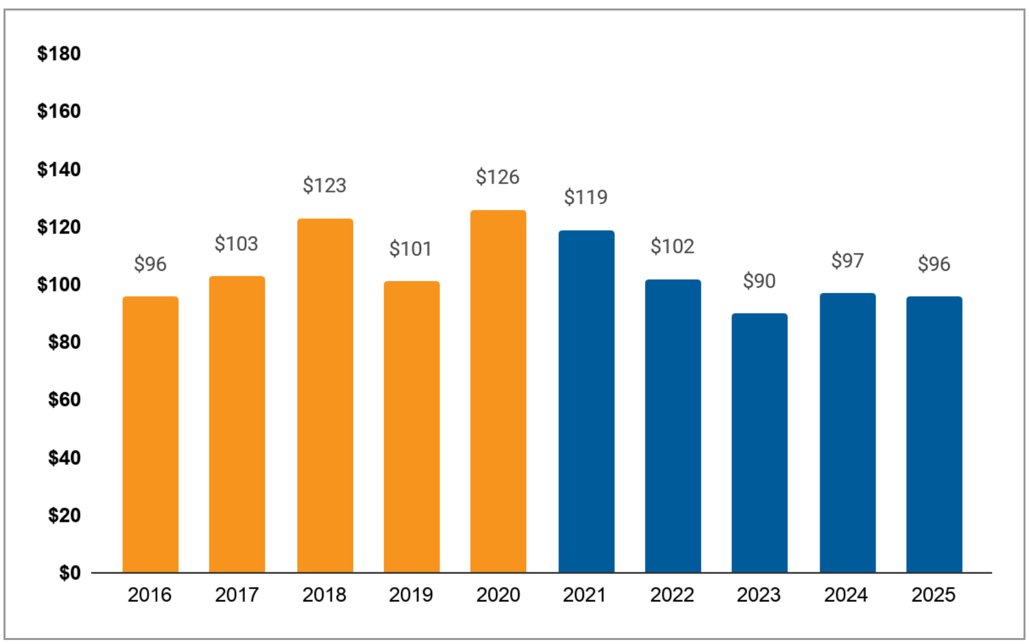
SUBJECT AREA: Rate Base

a) Please recast Figure 1 (Summary of 2016-2025 Annual Capital Expenditures) removing all capital expenditures related to the new facilities (both campuses).

RESPONSE:

a) Figure A presents a summary of annual capital expenditures excluding the Facilities Renewal Program (both campuses).

Figure A – Summary of 2016-2025 Annual Capital Expenditures Excluding Facilities Renewal Program ($'000,000s)



INTERROGATORY RESPONSE - VECC-43

2.0-VECC-43

EXHIBIT REFERENCE:

Exhibit 2, Tab 4, Schedule 6, page 10, Attachment A,

SUBJECT AREA: Reliability

a) Please update Tables 7, 8 and 9 (outages by cause code) to include 2019 results.

b) Please update Appendix 2-G to show 2019 service reliability results.

RESPONSE:

a) For an updated version of Table 7 that includes 2019 results, please see the response to interrogatory SEC-34. For updated versions of Tables 8 and 9 that include 2019 results, please see the response to interrogatory SEC-57.

b) Please see the response to interrogatory CCC-38 for the updated Service Reliability Metrics with 2019 values.

INTERROGATORY RESPONSE - VECC-44

2.0-VECC-44

EXHIBIT REFERENCE:

Exhibit 2, Tab 4, Schedule 3, page 58

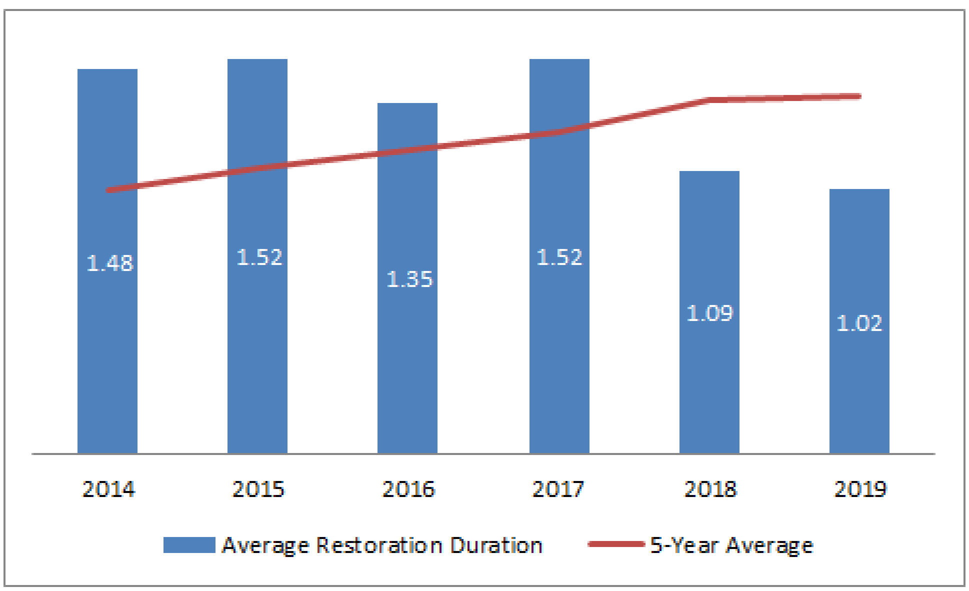
SUBJECT AREA: Distribution System Plan

a) Please update Figure 4.3 to include 2019 results.

RESPONSE:

a) Figure A is an updated version of Figure 4.3, with 2019 results included.

Figure A – CAIDI Reliability Performance



INTERROGATORY RESPONSE - VECC-45

2.0-VECC-45

EXHIBIT REFERENCE:

Exhibit 2, Tab 4, Schedule 3, page 67/79/81

SUBJECT AREA: Distribution System Plan

a) Please update Table 4.11 – Defective Equipment SAIFI per 100 Customers – to include 2019 results.

b) Please update Table 4.23 – Reliability Performance by Cause Code – to include 2019 results.

c) Please update Table 4.12 – Defective Equipment Historical Trends – to include 2019 results.

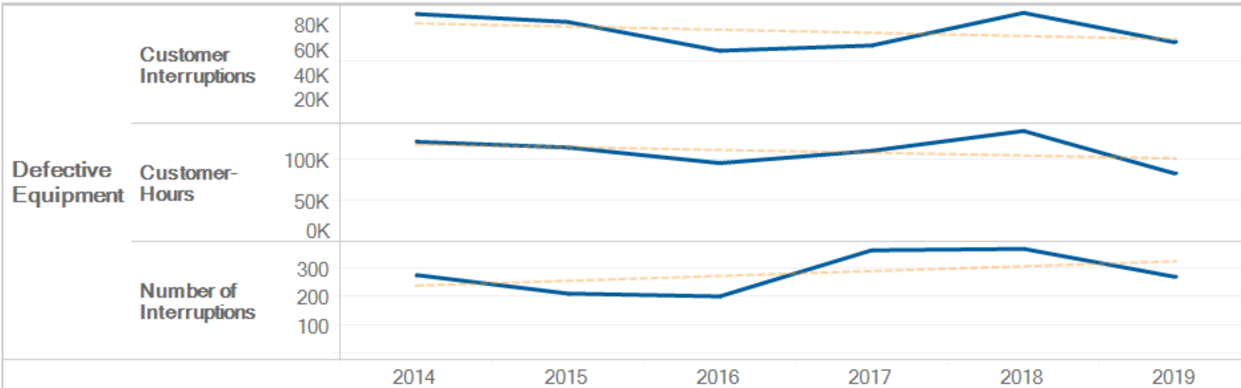
RESPONSE:

a) Please refer to part (d) of the response to interrogatory SEC-34.

b) Please refer to part (a) of the response to interrogatory SEC-34.

c) Please see Figure A below, which is an updated version of Table 4.12, with 2019 results included.

1 **Figure A – Defective Equipment Historical Trends**

2 

INTERROGATORY RESPONSE - VECC-46

2.0-VECC-46

EXHIBIT REFERENCE:

Exhibit 2, Tab 4, Schedule 3

SUBJECT AREA: Distribution System Plan

a) Please provide a table showing for each year 2019 through 2025 the actual or forecast payments to Hydro One broken down by station/project in each year. Please provide for each project an indication of whether an agreement has been signed with Hydro One with respect to each project and if not when an agreement is expected.

b) Please provide separately a column showing any actual or expected true-ups to the CCRA agreements for each year.

RESPONSE:

a) Please see Table A below for a breakdown of forecast payments to Hydro One Networks.

1 **Table A – Forecast Payments to Hydro One Networks ($'000s)**

Project	Historical		Test					
	2019	2020	2021	2022	2023	2024	2025	Agreement
Hawthorne TS New 44kV Feeder	$(512)	$0	$0	$0	$0	$0	$0	Yes
New South TS- CCRA	$3,321	$29,077	$16,035	$0	$0	$0	$0	Yes
A6R Upgrade HONI-CCRA	$633	$0	$0	$0	$0	$730	$0	Yes
Woodroffe CCRA	$362	$0	$0	$0	$0	$0	$0	Yes
Merivale Rebuild CCRA	$65	$0	$0	$0	$0	$0	$0	Yes
Slater T1 Emerg- HONI Payment	$4	$0	$0	$0	$0	$0	$0	Yes
Limebank MTS T4 - HONI Payment	$20	$0	$800	$0	$0	$0	$0	No (2020)
Overbrook TO CCRA	$0	$0	$0	$100	$100	$200	$0	No(2020)
Riverdale CCRA	$0	$0	$0	$0	$0	$1,200	$1,200	No (2022)
New East STN (2021) CCRA	$0	$0	$0	$0	$100	$3,000	$3,000	No (2021)
Ellwood Stn True-up	$0	$720	$0	$0	$0	$0	$0	Yes
Orleans TS Feeder CCRA	$0	$190	$0	$0	$0	$0	$0	Yes
Overbrook XFMR Upgrade CCRA	$0	$0	$0	$110	$0	$0	$0	Yes
Uplands MS - HONI Payment	$0	$83	$83	$0	$0	$0	$0	Yes (2020)
Hawthorne 115 kV-True-up	$2,200	$0	$0	$0	$0	$0	$0	Yes

2

3 b) For actual or expected true-ups to CCRA payments, please see pages 330 and 336-337
4 of Exhibit 2-4-3: Distribution System Plan.

INTERROGATORY RESPONSE - VECC-47

2.0-VECC-47

EXHIBIT REFERENCE:

Exhibit 2, Tab 4, Schedule 3, page 64

SUBJECT AREA: Rate Base

a) Please provide a table showing the projected Fleet spending comparing the following table (Exhibit B Part 2 EB-2015-0004, page 366) with the actual fleet costs replacement subsequently incurred.

Table 123 - Project Expenditures

	Historical ($M)				Future ($M)			
2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
2.02	2.54	3.06	1.44	1.54	1.45	1.21	1.45	1.48

b) Please explain why the 2020 expenditures on fleet are significantly greater than that spent in 2019.

c) Please also explain why HOL underspent (by about 400k) on fleet purchases as compared to its forecast estimate in the last cost of service rate case.

RESPONSE:

a) Attachment 2-4-3(F): Fleet Replacement Program, Table 3 has the 2016-2018 comparison requested. Table A below replicates this information and also contains the 2019 actual compared to the 2019 OEB-approved level.

Table A – Summary of 2016-2019 Actual Spend vs. OEB-Approved Levels ($'000s)

	2016	2017	2018	2019	Total
OEB Approved Levels (EB-2015-0004)	$1,455	$1,209	$1,452	$1,480	$5,596
Actual Capital Expenditures	$2,619	$1,584	$1,195	$562	$5,960
Variance Over / (Under)	**$1,164**	**$375**	**$(257)**	**$(918)**	**$364**

b) The amount spent on Fleet in any given year fluctuates depending on the types of vehicles being replaced in that year, including deposits that have to be placed on long-lead order vehicles such as Bucket Trucks. As seen in Table A above, there were over-expenditures in 2016 and 2017. Subsequently, the underspending in 2018 and 2019 was intentional and the total five-year fleet replacement envelope was materially on forecast. Expenditures for 2020 are forecast to be higher than 2019, as required acquisitions were delayed from 2019. Please refer to Table 3 in Attachment 2-4-3(F): Fleet Replacement Program for the projected spend compared to the OEB-approved level over the five-year period.

c) It is unclear to Hydro Ottawa how the underspend of approximately $400K referenced in the question is derived. For purposes of this response, it is assumed to be from comparing 2016 to 2019, as shown in Table A above. However, Hydro Ottawa would note that the $364K in Table A represents an overspend not an underspend. With this overspend and the inclusion of the 2020 forecast, total five-year spending on Fleet replacement is forecast to be over plan by 2%. Differences in the individual years are largely timing differences on advancing or delaying some vehicle replacements to correspond with operational needs.

INTERROGATORY RESPONSE - VECC-48

2.0-VECC-48

EXHIBIT REFERENCE:

Exhibit 2, Tab 4, Schedule 3, Attachment D

SUBJECT AREA: Distribution System Plan

At Attachment D HOL provides a letter of opinion from a Mr. Eugene Shlatz from Navigant Consulting purporting to confirm that the DSP of HOL is compliant with the requirement of the Ontario Energy Board.

a) Please confirm (or correct) that Mr. Shaltz is based out of Burlington Massachusetts.

b) Please provide Mr. Shaltz's CV.

c) Please confirm (or correct) that Mr. Shaltz has never appeared before the Ontario Energy Board..

d) Please describe Mr. Shaltz's experience in the energy sector in Ontario.

e) Why does HOL consider Mr. Shaltz an expert in the matters of the Ontario Energy Board?

RESPONSE:

a) Mr. Shaltz is based out of Burlington, Vermont.

b) Please see page 10 of Attachment SEC-54(B): Navigant - Hydro Ottawa - Independent Review of DSP.

c) Hydro Ottawa confirms that Mr. Shaltz has previously appeared before the OEB.

d) Please see pages 10-16 of Attachment SEC-54(B): Navigant - Hydro Ottawa - Independent Review of DSP.

e) Hydro Ottawa considers Mr. Shaltz to be an expert in the matters of the OEB based on his and Navigant's experience, as described in SEC-54(B): Navigant - Hydro Ottawa - Independent Review of DSP.

INTERROGATORY RESPONSE - VECC-49

3.0-VECC-49

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, page 1 and Attachment C

(Original) Exhibit 3, Tab 1, Schedule 1, page 1

SUBJECT AREA: Load Forecast

Preamble:

The Original Application states (page 1): "*The sale and energy forecast utilized actual data on sales, customer numbers and connections, and actual purchases through December 2019*".

The Updated Application states (page 1): "*The sale and energy forecast utilized actual data on sales, customer numbers and connections, and actual purchases through December 2019*".

a) If both Applications were based on models using actual data through to December 2019, please explain what changed in the Update that led to revised load forecast.

b) Contrary to the May 5, 2020 cover letter, Attachment C in the Update does not indicate (by way of highlighting and strikethroughs) was changed from the original Application. Please provide a revised version of Attachment C indicating the changes per the update.

RESPONSE:

a) The original Application (filed on February 10, 2020) was based on the first run of Hydro Ottawa's unbilled report. The updates to the Application (filed on May 5, 2020) were based on the final run of the unbilled report used for Financial reporting. The forecast was updated to reflect the revised historical data. There was no change in the model specification or forecast drivers.

b) There were no changes to the report text. Changes were a result of the change to the reported historical sales data and forecast values. Itron only retained the final report. Hydro Ottawa has compared the original version of Attachment 3-1-1(C): Hydro Ottawa Long Term Energy and Demand Forecast with the UPDATED version. For reference, this comparison is included as Attachment VECC-49(A): Comparison of Original and UPDATED Attachment 3-1-1(C). Please note that by hovering over the highlighted cells, the old and new text will be displayed. Some highlights may appear as a change due to a table or graphic moving slightly compared to the original file.

Summary
2020-05-30 11:17:38 AM

Differences exist between documents.

New Document:
UPDATED Attachment 3-1-1(C)_ Hydro Ottawa Long-Term Electric Energy and Demand Forecast (produced by
47 pages (1.90 MB)
2020-05-30 11:17:15 AM
Used to display results.

Old Document:
Attachment 3-1-1 (C)_ Hydro Ottawa Long-Term Electric Energy and Demand Forecast
47 pages (1.23 MB)
2020-05-30 11:17:15 AM

Get started: first change is on page 1.

No pages were deleted

How to read this report

Highlight indicates a change.
~~**Deleted**~~ indicates deleted content.
indicates pages were changed.
indicates pages were moved.

Knowledge to Shape Your Future

Electric | Gas | Water
information collection, analysis and application

2019 Long-Term Electric Energy and Demand Forecast

Hydro Ottawa

Submitted to:

Hydro Ottawa
Ottawa, Ontario

Submitted by:

Itron, Inc.
20 Park Plaza
Suite 428
Boston, Massachusetts 02116
(617) 423-7660

March 2020

Contents

1 Overview

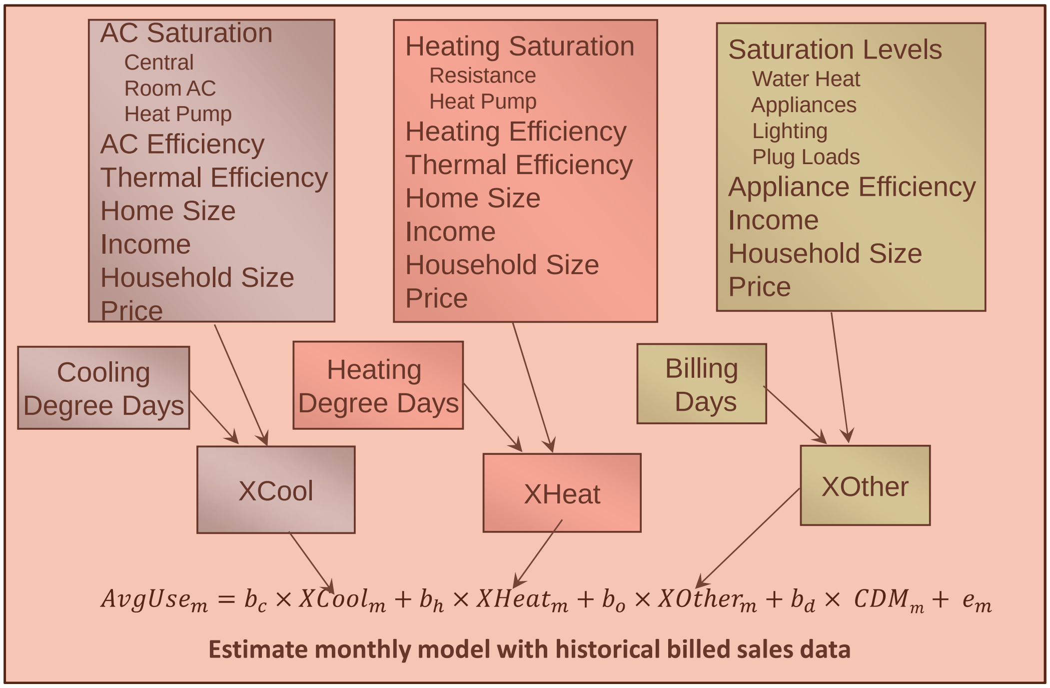
Itron, Inc. recently completed the 2020 to 2025 Hydro Ottawa sales and energy forecast. The forecast is based on actual sales, customer, and purchase data through December 2019. Forecasts are derived for rate class sales, customers, billing demands, system purchases and system peak demand. This document presents forecast results, assumptions, and an overview of the forecast methodology.

Hydro Ottawa serves approximately 311,500 residential customers and 28,300 nonresidential customers. Total 2019 sales equaled 7,241 GWh with a system peak of 1,398 MW. Residential customer class accounts for approximately 31% of system sales, small commercial 10% of sales (less than 50 kW), medium commercial customers 34% of sales (50 kW to 1,000 kW), and large commercial and industrial (greater than 1,000 kW) 24% of sales; Street lighting, municipal, and DCL account for remaining sales.

Over the last five years economic growth has been relatively steady with GDP averaging 2.1% annual growth; employment has been averaging 1.3% annual growth and population 1.6% per year annual growth. Yet despite this growth, electricity sales have been declining; weather-normalized sales averaged 0.7% decline between 2014 and 2019. Residential sales have declined 0.1% even while adding 25,000 customers over this period. The largest decline in sales is in the nonresidential rate classes where sales have been falling 1.0% per year.

Improvements in energy efficiency are a significant contributor to decline in electric sales. New end-use standards, improvements in thermal shell integrity, and energy-efficiency program activity (CDM) have more than compensated for increase in regional population growth and business activity. To capture the efficiency trends, forecasts for the residential and commercial rate classes are estimated using a Statistically Adjusted End-Use Models (SAE) modeling framework. The modeling approach entails explicitly incorporating end-use energy intensity trends as well as population growth, economic activity, and weather conditions into the constructed monthly model variables for cooling (XCool), heating (XHeat), and other uses (XOther). Figure 1 shows the general residential SAE modeling framework.

Figure 1: Residential SAE Model Framework



Estimated SAE model coefficients – b_c, b_h, and b_o calibrate end-use load estimates (XCool, XHeat, and XOther) to actual billed customer usage. Estimated monthly CDM savings are included as a separate variable to capture program efficiency impacts not captured by end-use intensities. Projections of end-use intensities, economic activity, weather conditions, and CDM drive monthly average use. Residential sales are estimated by combining average use forecast with residential customer forecast. A similar SAE specification is used for the commercial rate classes, but models are estimated using total sales rather than average use.

The forecast is derived from monthly regression models estimated for both rate classes and system peak; system purchases are derived by applying an average loss factor to rate-class sales forecast. Rate class sales, and customer forecast models are estimated for the following rate classes.

- Residential
- GS50 (less than 50 kW)
- GS1000 (50 kW – 1000 kW)
- GS1500 (1000 kW to 1500 kW)
- GS5000 (1500 kW to 5000 kW)
- Large Users (5000 kW plus)
- Street Lighting
- MU
- DCL

Residential sales forecast is derived as the product of average use and customer forecast. The commercial and other customer classes are based on total sales models. Models are estimated with monthly sales beginning in 2013. Starting in 2013, Hydro Ottawa changed the method used in estimating monthly customer class sales. The new method significantly improved the historical data series that in turn allows us to estimate relatively strong statistical-based sales forecast models. Table 1 shows the rate class sales forecast.

Table 1: Rate Class Forecast

Class Sales Forecast (MWh)										
Year	Res	GS 50	GS 1000	GS I 50-1000kW	GS 1000-1500kw	GS 1500-5000kw	Large Users	Street Lght	MU	DCL
2013	2,256,550	720,479	1,556,240	1,106,483	343,409	857,551	613,514	44,767	17,055	3,407
2014	2,241,046	714,941	1,472,036	1,120,521	333,082	872,269	607,321	44,364	16,413	3,516
2015	2,242,518	723,755	1,392,724	1,181,623	374,916	867,663	564,804	45,152	15,998	3,492
2016	2,260,336	733,312	1,328,249	1,208,311	385,291	805,584	588,873	45,206	15,659	3,547
2017	2,188,889	712,369	1,259,105	1,214,651	399,393	753,196	606,157	38,204	15,230	3,630
2018	2,318,157	727,991	1,255,925	1,256,092	426,660	723,849	608,578	31,723	14,861	3,933
2019	2,263,478	724,441	1,185,637	1,303,050	392,965	723,018	602,083	26,731	14,550	4,923
2020	2,254,425	707,565	1,130,274	1,321,227	386,744	701,742	588,827	24,063	14,105	4,993
2021	2,252,938	699,870	1,080,526	1,351,425	385,754	682,921	574,291	22,108	13,601	4,993
2022	2,273,819	699,135	1,041,854	1,394,293	386,993	682,300	572,889	21,224	13,131	4,993
2023	2,299,366	697,637	1,003,314	1,437,626	388,277	682,504	572,034	20,413	12,663	4,993
2024	2,333,197	697,775	967,025	1,484,412	390,553	684,408	572,834	19,602	12,194	4,993
2025	2,353,150	695,838	926,027	1,525,262	391,593	683,533	570,390	18,855	11,727	4,993

System purchase and peak demand forecast are driven by underlying sales forecast. Purchases are calculated as the product of the total sales forecast and monthly adjustment factors that reflect both system losses and timing between monthly sales estimates and monthly purchases. The system peak forecast is derived from a monthly regression model that relates peak demand to heating, cooling, and base-use loads and peak-day weather conditions. Heating, cooling, and base-use load estimates are derived from the rate class sales forecasts. Table 2 shows actual sales, purchases, and peak demand through 2019 and forecast starting in 2020.

Table 2: System Forecast

Year	Total Sales (MWh)	chg	System Purchases (MWh)	chg	Peak Demand (MW)	chg
2013	7,519,455		7,722,175		1,427	
2014	7,425,509	-1.2%	7,636,154	-1.1%	1,304	-8.6%
2015	7,412,645	-0.2%	7,622,794	-0.2%	1,392	6.7%
2016	7,374,368	-0.5%	7,600,820	-0.3%	1,407	1.1%
2017	7,190,824	-2.5%	7,410,784	-2.5%	1,369	-2.7%
2018	7,367,769	2.5%	7,612,656	2.7%	1,481	8.2%
2019	7,240,876	-1.7%	7,458,493	-2.0%	1,398	-5.6%
2020	7,133,965	-1.5%	7,353,252	-1.4%	1,458	4.3%
2021	7,068,427	-0.9%	7,285,713	-0.9%	1,452	-0.4%
2022	7,090,631	0.3%	7,308,596	0.3%	1,460	0.6%
2023	7,118,827	0.4%	7,337,656	0.4%	1,468	0.5%
2024	7,166,993	0.7%	7,387,271	0.7%	1,480	0.8%
2025	7,181,368	0.2%	7,402,111	0.2%	1,487	0.5%
2013-19		-0.6%		-0.6%		-0.2%
2020-25		0.1%		0.1%		0.4%

2 Forecast Data and Assumptions

2.1 Historical Class Sales and Energy Data

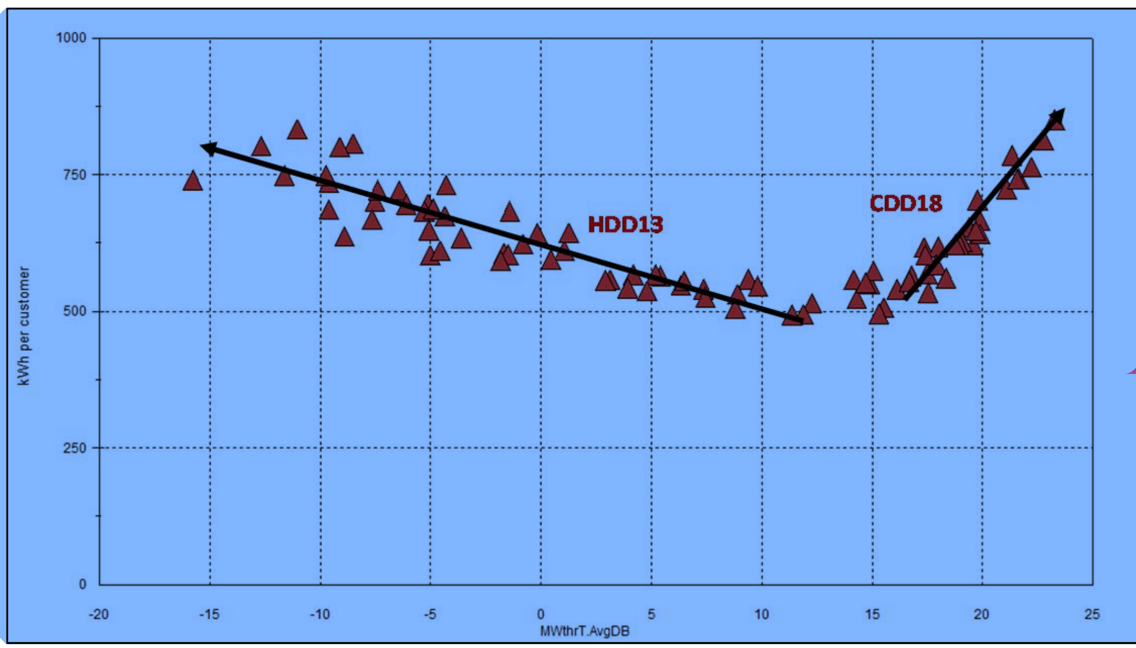
Rate class linear regression models are estimated using monthly billed sales and customer data from January 2013 through December 2019. Prior to 2013 the monthly billed sales data is a poor measure of what was actually used during the calendar month; unbilled sales estimates were significantly improved beginning in 2013. In the prior rate-case forecast, the poor rate class data quality required us to calibrate initial rate class sales forecast to a monthly purchase sales forecast. In this forecast there is no calibration process as there is enough historical monthly rate class sales data that is consistent with monthly weather conditions to estimate relatively strong statistical-based models.

System peak demand forecast is based on reported monthly peaks from January 2013 to December 2019. While demand data is available prior to 2013, as this year's is a total "bottom-up" forecast driven by rate class forecast, there is no need for demand data prior to this point. System purchases are not directly used in the forecast. System purchases are used to calculate average monthly "loss" factors based on the historical relationship between monthly purchases and retail sales over the four-year period 2015 to 2018.

2.2 Weather Data

Actual and normal Heating Degree Days (HDD) and Cooling Degree Days (CDD) are calculated from daily average temperature and dew point data for Ottawa. Generally, degree-days are expressed with a basis of 18 degrees Celsius. We found we can improve on the forecast model statistical fit by defining HDD with 13 degree-day bases as there is little heating when temperatures are above 13 degrees. Between 13 degrees and 18 degrees there is little heating or cooling. Figure 2 illustrates this point.

Figure 2: Residential Average Use vs Monthly Average Temperature



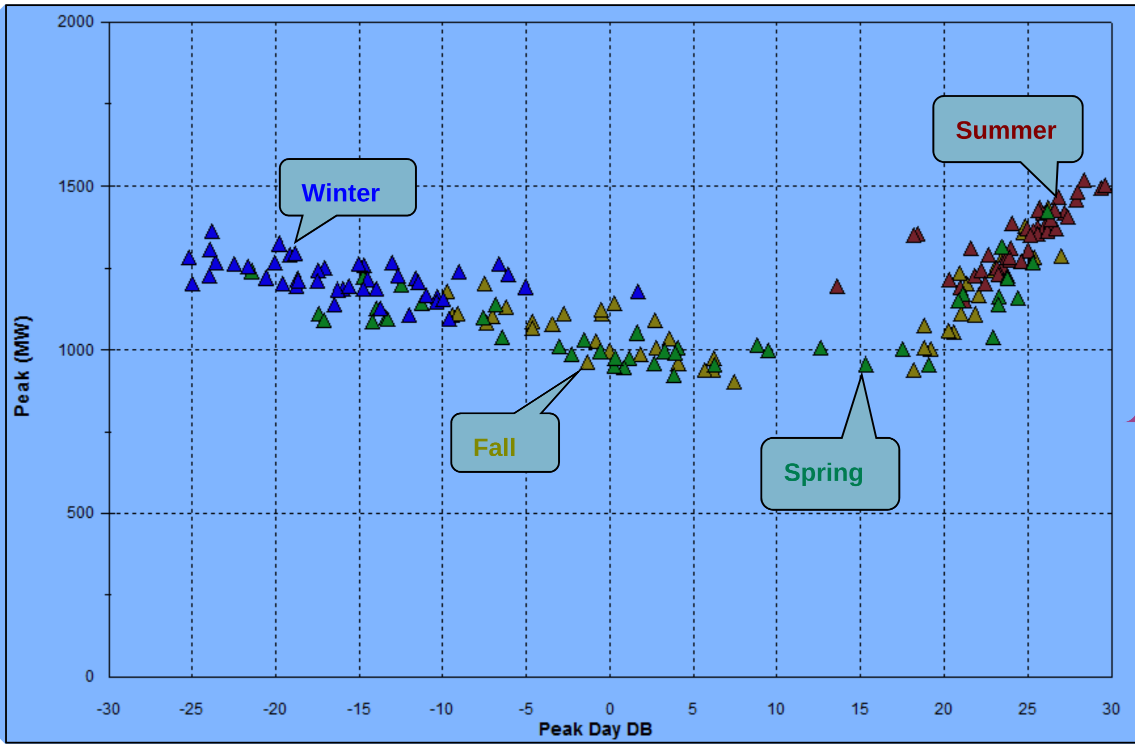
Normal monthly degree-days are calculated as an average of monthly degree-days over the past twenty years – 1999 through 2018.

Peak-Day Weather Variables

Monthly peak-day HDD and TDD (temperature-humidity based degree-days) are used in forecasting peak demand. Peak-day degree-days are based on the average daily temperature and dew point that occurs on the day of the monthly peak. TDD is a two-day weighted temperature as we found prior-day temperature has a significant impact on demand. The weights are 55% for the day of the peak and 45% for the day prior to the peak.

The appropriate breakpoints for the HDD and weighted TDD variables are determined by evaluating the relationship between monthly peak and the peak-day average temperature as shown in Figure 3.

Figure 3: Monthly Peak Demand /Temperature Relationship



From the scatter plot (and initial regression models) the "best" fit TDD variable is where TDD is defined with a THI base of 13 degrees and the best breakpoint for calculating the peak-day HDD variable is 10 degrees.

Normal peak-day HDD and TDD are derived as a twenty-year average using a *rank and average* approach. This approach entails first finding the highest HDD and TDD that occurred in each month over the last twenty years (1999 to 2018), and within each year ranking the degree-days from the highest to the lowest value so that there are 12 monthly ranked HDD and TDD in each year. The ranking across the years are then averaged effectively generating peak-weather TDD and HDD duration curves with 12 average values. The ranked-average TDD and HDD are assigned to specific months based on that peak-month TDD or HDD is most likely to occur. The highest weighted TDD is assigned to July, the next highest August, the third highest June, and so forth. The highest HDD value is assigned to January, the next highest to February, the third highest to December, and so forth.

2.3 Economic Data

Rate class sales forecasts are based on the Conference Board's November 2019 economic forecast for the Ottawa and Gatineau area. The primary economic drivers are population, real personal income (RPI), GDP, and Employment. Table 3 shows the historical and forecasted economic drivers.

Table 3: Ottawa Regional Economic Forecast

Year	Population (000's)	Chg	GDP (Millions $)	Chg	RPI (Millions $)	Chg	Employment (000's)	Chg
2013	1,315		70,088		50,178		695.6	
2014	1,326	0.9%	70,990	1.3%	49,675	-1.0%	706.9	1.6%
2015	1,337	0.8%	72,419	2.0%	50,919	2.5%	711.0	0.6%
2016	1,358	1.6%	73,856	2.0%	51,828	1.8%	718.8	1.1%
2017	1,385	2.0%	75,829	2.7%	53,020	2.3%	726.3	1.0%
2018	1,414	2.1%	77,674	2.4%	54,242	2.3%	739.5	1.8%
2019	1,439	1.7%	78,927	1.6%	55,483	2.3%	753.9	1.9%
2020	1,459	1.4%	80,431	1.9%	56,103	1.1%	758.9	0.7%
2021	1,478	1.3%	81,890	1.8%	56,926	1.5%	765.0	0.8%
2022	1,497	1.3%	83,458	1.9%	58,170	2.2%	776.5	1.5%
2023	1,516	1.3%	85,010	1.9%	59,532	2.3%	788.4	1.5%
2024	1,535	1.3%	86,591	1.9%	60,888	2.3%	800.5	1.5%
2025	1,555	1.3%	88,218	1.9%	62,320	2.4%	813.0	1.6%
2013-20		1.5%		2.0%		1.6%		1.3%
2020-25		1.3%		1.9%		2.1%		1.4%

2.4 Appliance Saturation and Efficiency Trends

End-use intensities are calculated from end-use saturation estimates (the share of homes that own a specific appliance) and measure of equipment efficiency. As saturation increases, energy intensity increases. As efficiency improves end-use intensity decreases. Declining customer average use is largely attributable to efficiency gains that have been stronger then increases in end-use saturations. Starting residential end-use intensity estimates are based on the Energy Information Administration (EIA) historical and projected end-use saturation, stock efficiency and appliance usage data from the 2019 Annual Energy Outlook (AEO). The AEO forecast is based on the National Energy Modeling System (NEMS) which includes end-use forecast modules for the residential and commercial sectors. Residential data derived from NEMS database include:

- End-use consumption
- End-use stock energy efficiency (for some measures and UECs for others)
- End-use appliance stock (number of existing units)
- End-use saturation (calculated from number of units and number of households).

EIA develops end-use forecasts for nine census division. The end-use intensity forecasts are based on the Mid-Atlantic Census Division which includes New York. Intensities are modified to reflect Ontario end-use saturation trends; historical and forecasted end-use saturations are calibrated to reported saturation data from Natural Resources Canada for Ontario (NRCan). We assume that the end-use average stock efficiency in Hydro Ottawa's service territory is similar to that of the Mid-Atlantic Census Division.

Figure 4 shows the resulting end-use intensities aggregated to Heating, Cooling, and Other Use. Figure 5 gives a breakdown of Other Use by end-use detail.

Figure 4: Major Residential End-Use Intensities (kWh per HH)

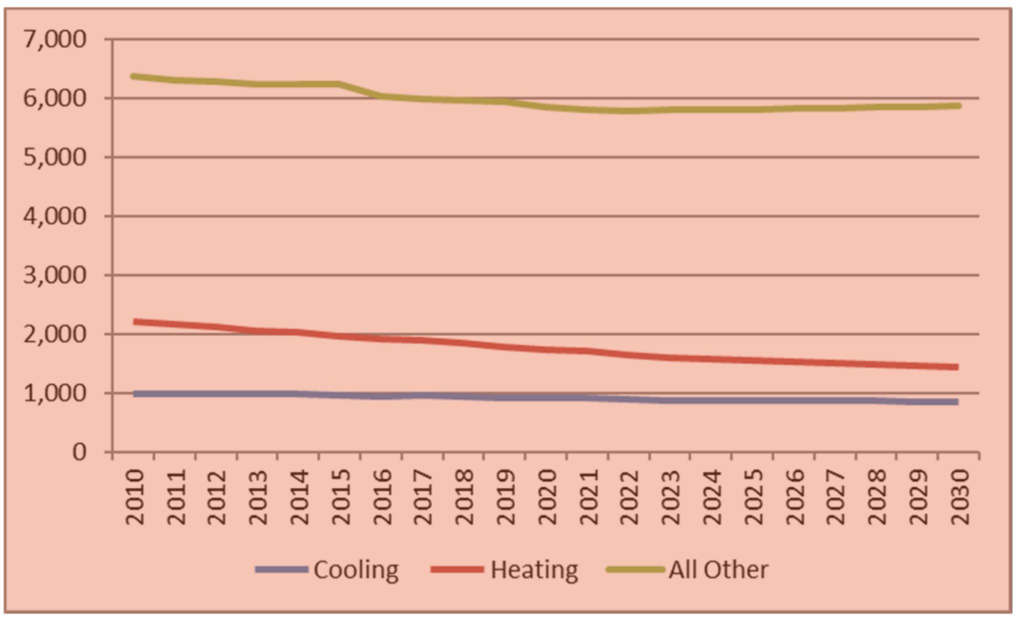
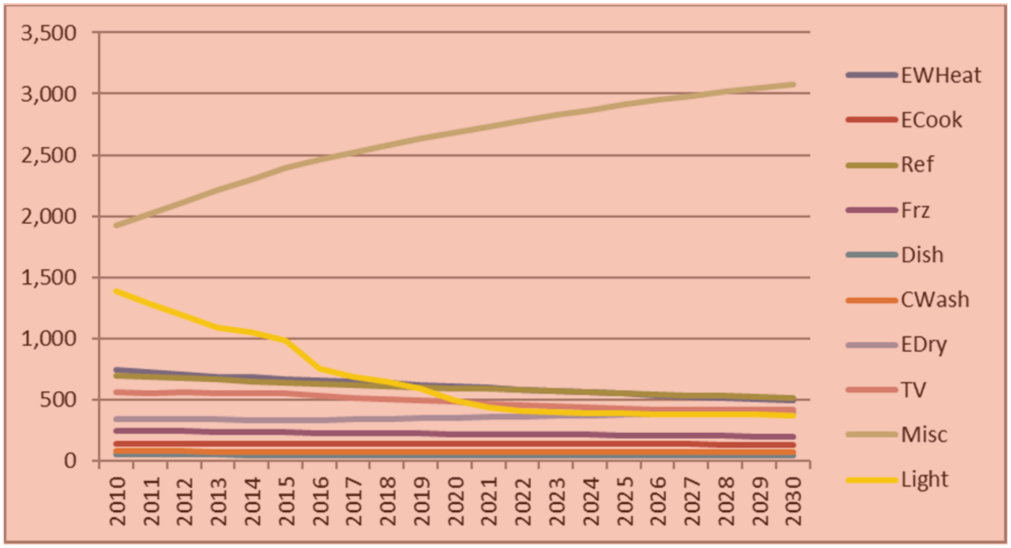


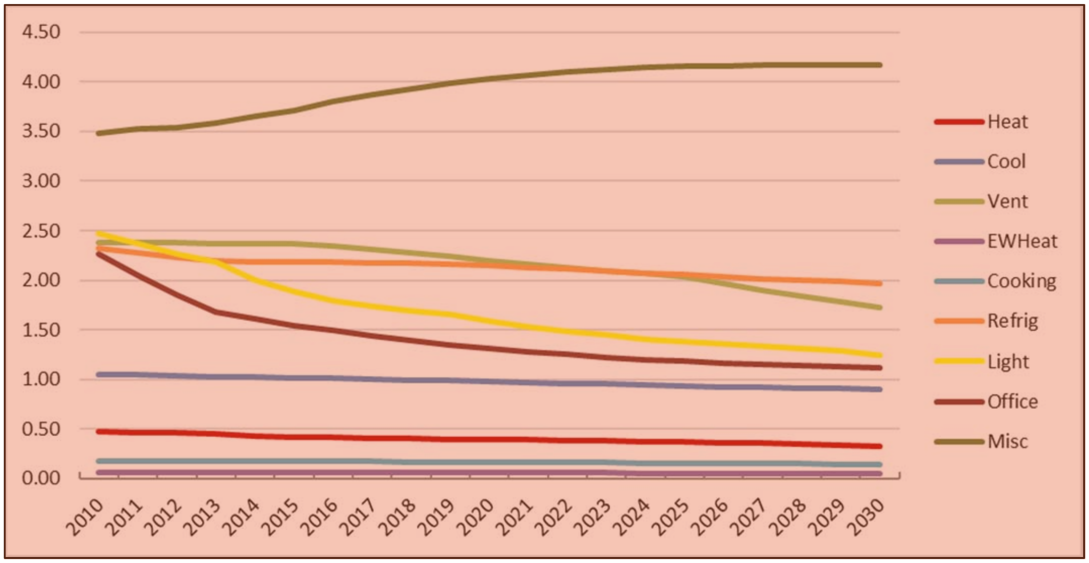
Figure 5: Residential Other Use Energy Intensities (kWh per HH)



End-use intensities are generally declining as efficiency is increasing faster than appliance ownership. Most end-uses intensities change slowly over time as appliances are replaced with more efficient options. The exceptions are lighting and miscellaneous which are also the two largest end-uses. Lighting intensity has declined sharply over the past 5 years with the phase-in of new lighting standards and increase in LED market share. Miscellaneous sales growth has been countering some of the impact of declining lighting use; miscellaneous includes everything from home electronics to electric outdoor equipment.

EIA provides commercial end-use forecast by building type. There are 11 building types and 9 end-uses. End-use data includes consumption and square footage. Commercial end-use intensities are derived by dividing commercial end-use consumption by square footage. Other than the miscellaneous end-use, commercial end-use energy intensities are either flat or declining. Figure 6 shows commercial end-use intensity trends.

Figure 6: Historical and Projected Commercial End-Use Intensities (kWh per square foot)



2.5 Conservation and Demand Management (CDM)

End-use intensity projections also reflect regional conservation activity. EIA model's efficiency program impacts by reducing the costs (through "rebates") of the more efficient technology options. For Ottawa, sales and average use decline even faster than that reflected in the end-use intensity projections. Differences is likely due to more CDM activity than that embedded in the estimated model and end-use intensity trends. To capture additional CDM savings, cumulative CDM savings are included as a model variable. Historical and forecasted CDM are estimated for each rate class. Cumulative CDM forecast is summarized in Table 4.

Table 4: CDM Forecast

	Cumulative CDM Saving (MWh)			
Year	Residential	Small Commercial	Commercial	Street Light
2020	11,137	19,564	128,540	4,945
2021	14,747	23,948	144,582	5,756
2022	15,239	28,333	160,623	6,566
2023	15,731	32,717	176,665	7,377
2024	16,223	37,102	192,706	8,188
2025	16,715	41,486	208,748	8,999

3 Forecast Methodology

3.1 Class Sales Forecast

Changes in economic conditions, weather conditions, end-use energy intensity trends, and CDM drives electricity use and demand through a set of monthly rate class regression models. Models are estimated for the following rate classes:

- Residential
- GS50 (Less than 50 kW)
- GS1000 (50 kW – 1000 kW)
- GS1500 (1000 kW – 1500 kW)
- GS5000 (1500 KW – 5000 kW)
- Large Users (Over 5000 kW)
- Street Lighting
- MU
- DCL

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3.1.1 Residential Model

The residential monthly sales forecast is derived as the product of the average use and customer forecast. The forecast captures population and income growth as well improvements in energy efficiency through an SAE model specification.

Average Use Forecast

Residential average use is modeled as a function of heating requirements (XHeat), cooling requirements (XCool), and other use (XOther). Cumulative CDM savings are incorporated to capture program savings not captured in the end-use model variables. The general specification for the average use model is:

$$AvgUse_m = B_0 + (B_1 \times XHeat_m) + (B_2 \times XCool_m) + (B_3 \times XOther_m) + (B_4 \times CDMPerCust_m) + e_m$$

Model variables – *Xheat, XCool*, and *XOther* account for both economic activity and improvements in end-use efficiency. *XHeat* for month *m* is calculated as:

$XHeat_m = HDDIdx_m \ x \ IncIdx^{0.15}{}_m \ x \ HeatIntensity_a$

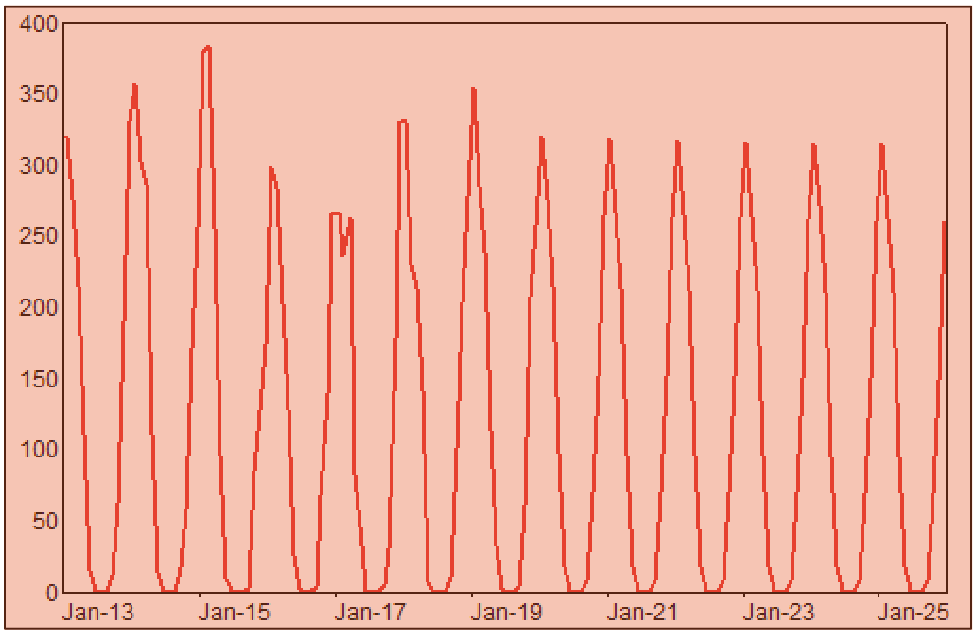
Where

- $HDDIDX_m$ = an index of monthly actual and normal HDD

- $IncIdx_m$ = indexed per capita income (a 0.15 elasticity is applied to capture small impact on heating use)
- $HeatIntensity_a$= annual end-use heating intensity trend (kWh per household)

As *HeatIntensity* is measured in kWh and HDD and Income are indexed, the result is an estimate of historical and forecasted monthly heating kWh use. Figure 7 shows the calculated XHeat variable.

Figure 7: Residential XHeat Variable



XCool is derived in a similar manner:

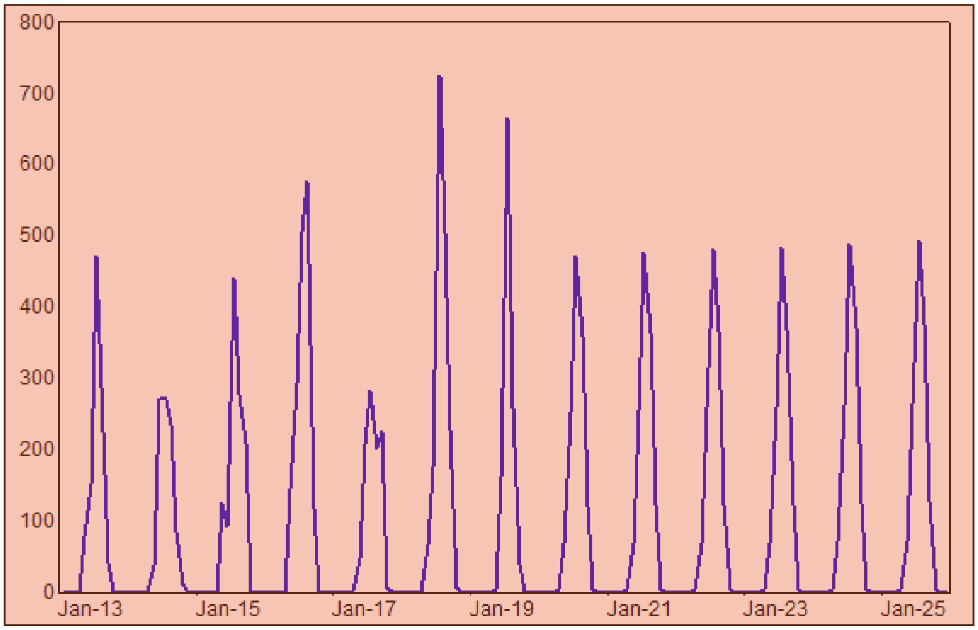
$$XCool_m = CDDIdx_m \times IncIdx^{0.15}_m \times CoolIntensity_a$$

Where

- $CDDIDX_m$ = an index of monthly actual and normal CDD
- $IncIdx_m$ = indexed per capita income (a 0.15 elasticity is applied to capture small impact on heating use)
- $CoolIntensity_a$= annual end-use cooling intensity trend (kWh per household)

Figure 8 shows the calculated XCool variable.

Figure 8: Residential XCool Variable



XOther captures non-weather sensitive end-use

$$XOther_m = DaysIdx_m \times IncIdx^{0.15}_m \times OtherIntensity_a \times MonthlyMultiplier_m$$

Where

- $DaysIdx_m$ = an index for the number of days per month
- $IncIdx_m$ = indexed per capita income (a 0.15 elasticity is applied to capture small impact on heating use)
- $OtherIntensity_a$= annual non-weather sensitive end-use intensity trend (kWh per household)
- $MoMultiply_m$= monthly end-use usage fraction (fraction of annual usage)

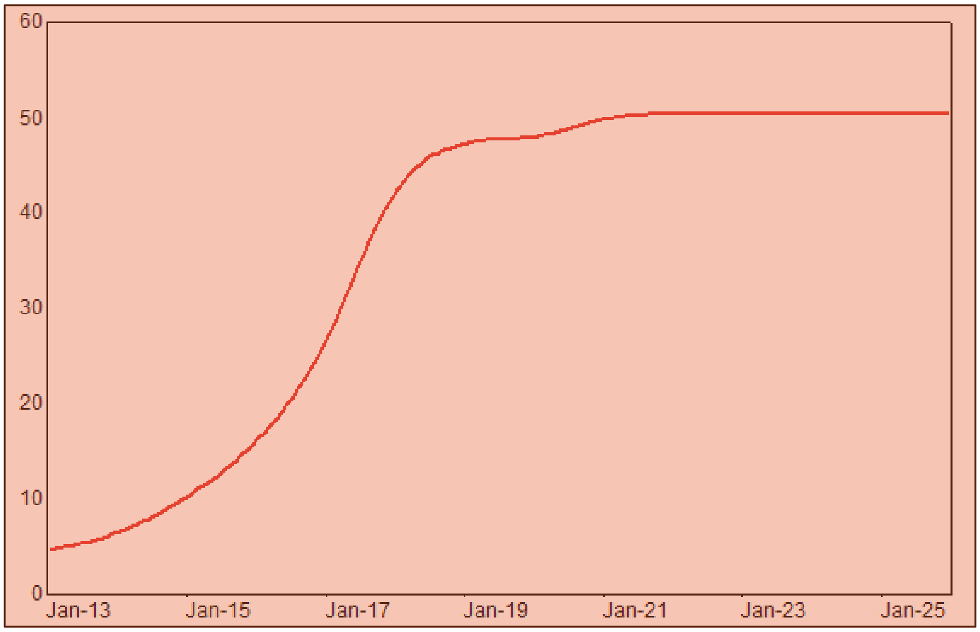
Figure 9 shows the calculated XOther variable.

Figure 9: Residential XOther Variable

The monthly pattern reflects both estimated number of days and relative amount of end-use energy use across the months. More lighting and water heating load occur in the winter months than summers months and slightly more refrigeration and freezer loads occur in the summer months than winter months.

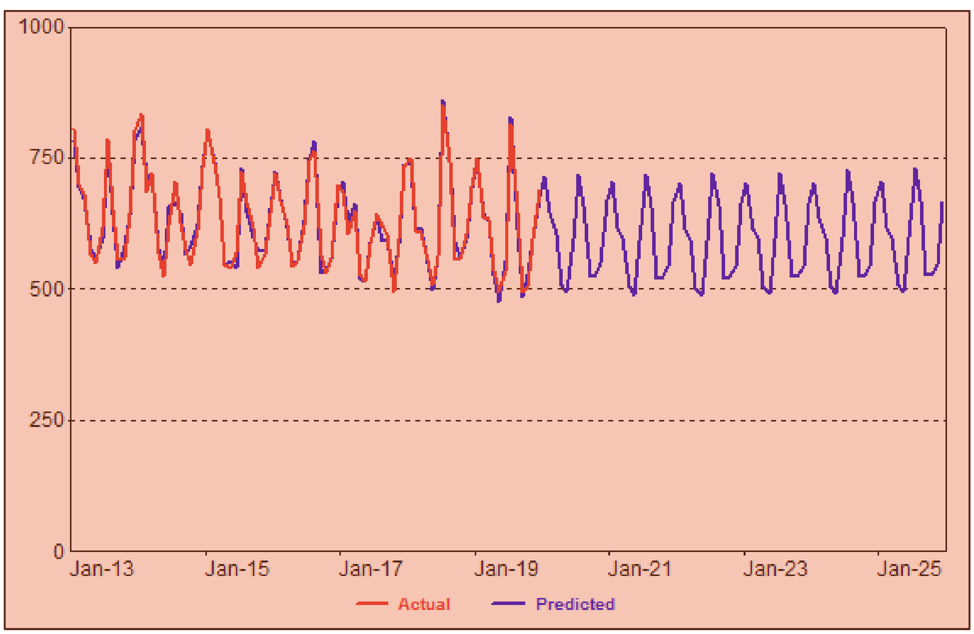
Cumulative CDM starts in 2013 at an estimated average per customer 5 kWh per month (60 kWh per year) and increases to 48 kWh per month (576 kWh per year) by 2019. Projected CDM growth slows considerably after 2019 reaching 50 kWh per month by 2021. Figure 10 shows the residential per customer CDM projections.

Figure 10: Residential Per Customer CDM



Residential average use model is estimated as a function of Cooling, Heating, Other Use, and CDM per customer savings over the period January 2013 through December 2019. The model is used in generating average use forecast through December 2025. Figure 11 shows actual and predicted average use.

Figure 11: Actual and Predicted Residential Average Use (kWh)



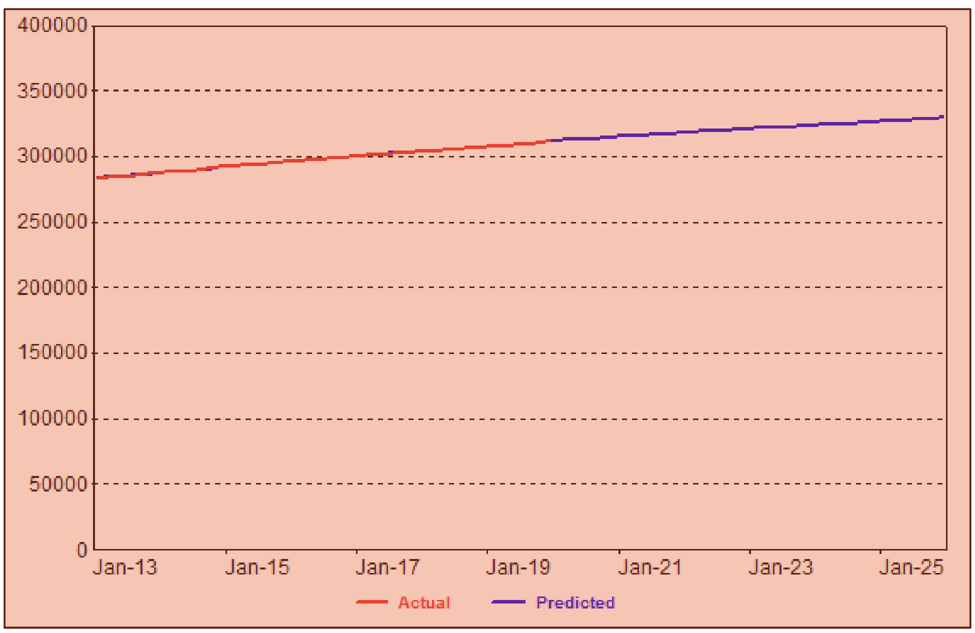
The estimated model explains historical sales well with an Adjusted R-Squared of 0.96 and a mean absolute percent error (MAPE) of 2.0%. The model variables are all strongly statistically significant. The model also includes binary variables for March, April, May, and November and shifts in usage in 2015 and 2016 that can't be explained by available data. Estimated model coefficients, coefficient statistics, and model statistics are included in Appendix A.

Customer Forecast

The customer forecast is based on a monthly regression model that relates number of customers to population projections; the correlation between number of customers and population is extremely high at 0.98. Monthly binaries are included to capture small variation in monthly customer counts.

Figure 12 shows actual and predicted customers.

Figure 12: Actual and Predicted Residential Customer



While number of customers continue to increase, the rate of growth is slowing along with the population. Over the last five years Hydro Ottawa added on average 3,950 new customers per year down from 4,430 customers per-year in the prior five-year period. Based on population projections, customer growth is expected to increase approximately 3,000 per year over the next five years.

Sales Forecast

The residential sales forecast is the product of average use and customer forecast. Table 5 shows annual average use, customer, and resulting sales forecast. Forecast begins in 2020.

Table 5: Residential Forecast

Residential Forecast						
Year	Average Use (kWh)	chg	Customers	chg	Sales (MWh)	chg
2013	7,919		284,964		2,256,550	
2014	7,744	-2.2%	289,385	1.6%	2,241,046	-0.7%
2015	7,631	-1.5%	293,884	1.6%	2,242,518	0.1%
2016	7,585	-0.6%	298,001	1.4%	2,260,336	0.8%
2017	7,252	-4.4%	301,839	1.3%	2,188,889	-3.2%
2018	7,591	4.7%	305,390	1.2%	2,318,157	5.9%
2019	7,321	-3.6%	309,165	1.2%	2,263,478	-2.4%
2020	7,200	-1.7%	313,134	1.3%	2,254,425	-0.4%
2021	7,122	-1.1%	316,346	1.0%	2,252,938	-0.1%
2022	7,119	0.0%	319,386	1.0%	2,273,819	0.9%
2023	7,134	0.2%	322,306	0.9%	2,299,366	1.1%
2024	7,176	0.6%	325,150	0.9%	2,333,197	1.5%
2025	7,175	0.0%	327,975	0.9%	2,353,150	0.9%
2013-19		-1.3%		1.4%		0.1%
2020-25		-0.1%		0.9%		0.9%

3.1.2 Commercial Forecast Models

Like the residential model, the commercial SAE sales models express monthly sales as a function of heating requirements (XHeat), cooling requirements (XCool), other use (XOther), and CDM sales. Hydro Ottawa has multiple commercial rate classes that are defined by customer demand requirements. While separate sales forecast models are estimated for each rate class, the model structure is basically the same:

$$ComSales_m = B_0 + B_1 XHeat_m + B_2 XCool_m + B_3 XOther_m + B_4 CDM_m + e_m$$

- $XHeat_m = \mathrm{EI_{heat}} \times \mathrm{EconVar_m} \times \mathrm{HDD_m}$
- $XCool_m = \mathrm{EI_{cool}} \times \mathrm{EconVar_m} \times \mathrm{CDD_m}$
- $XOther_m = \mathrm{EI_{other}} \times \mathrm{EconVar_m}$

Where:
EI = Annual energy intensity (kWh per square feet)
$\mathrm{EconVar}_m$ = Economic driver for month m

The commercial end-use intensities (EI) are aggregated into heating, cooling, and other use; intensities incorporate both end-use saturation increases and improvements in efficiency. The economic variable ($EconVar_m$) is weighted between population and GDP. Population captures increase in market size and GDP overall business activity. Employment was also evaluated as model driver but provided no additional information than that captured by population and GDP growth. The weights are slightly different for small commercial and large commercial rate classes; the weights are equal for the small commercial rate class with higher weighting on GDP for the larger rate classes:

- $SmlEconVar_m = Pop_m^{0.5} \times GDP_m^{0.5}$
- $LrgEconVar_m = Pop_m^{0.2} \times GDP_m^{0.8}$

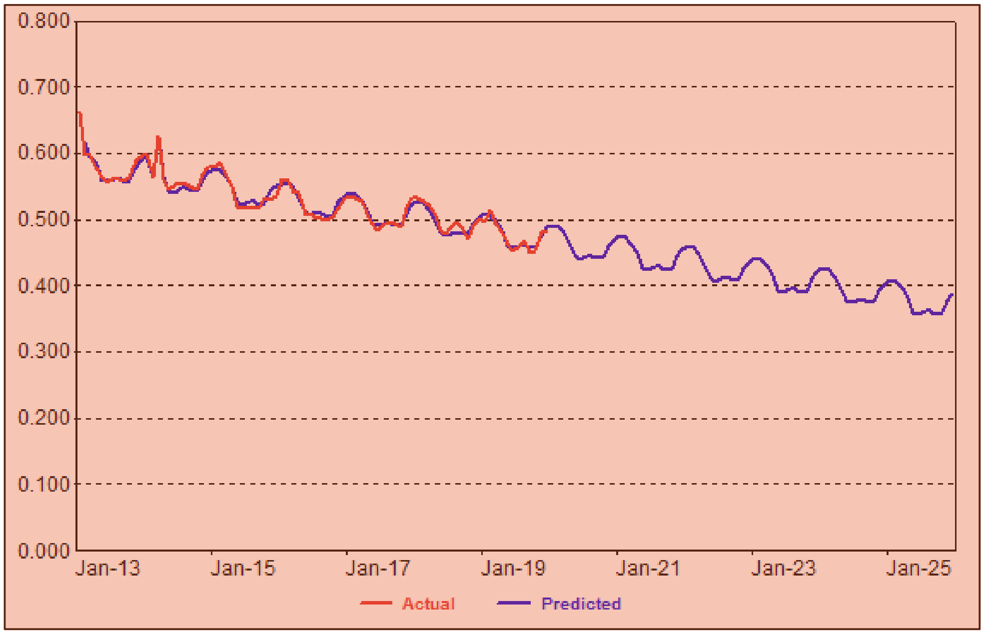
The weights are determined by evaluating out of sample model fit statistics for different sets of weight. The variables are geometrically weighted as population and GDP are measured on different scales.

Commercial sales models are estimated over the period January 2013 to December 2019. The model in-sample fits are relatively strong with Adjusted R-Squared ranging from 0.88 to 0.94 and MAPEs of 1.6% to 2.7%

Since 2013, GS1000 customers have been migrating to interval metering; interval metered customers (GS1000I) are priced with a different billing structure than non-interval customers (GS1000NI). A simple trend-based share model is used to disaggregate sales between the two services.

Figure 13 shows actual and predicted (declining) share of non-interval sales.

Figure 13: Actual and Predicted GS1000NI Share



Forecast for GS1000NI sales are derived as the product of the non-interval share and GS1000 sales forecast. Forecast for GS1000I is calculated as GS1000 sales forecast less GS1000NI sales forecast.

Figure 14 to

Figure 17 shows actual and predicted sales for the commercial rate classes. Estimated model coefficients and model statistics are included in Appendix A. Model predicted results include CDM except for the GS1500 and GS5000 rate classes. For GS1500, GS5000, Large Users, MU and Street Lighting CDM adjustments are made by subtracting future CDM savings from the model predicted results.

Figure 14: Actual and Predicted GS50 Sales (MWh)

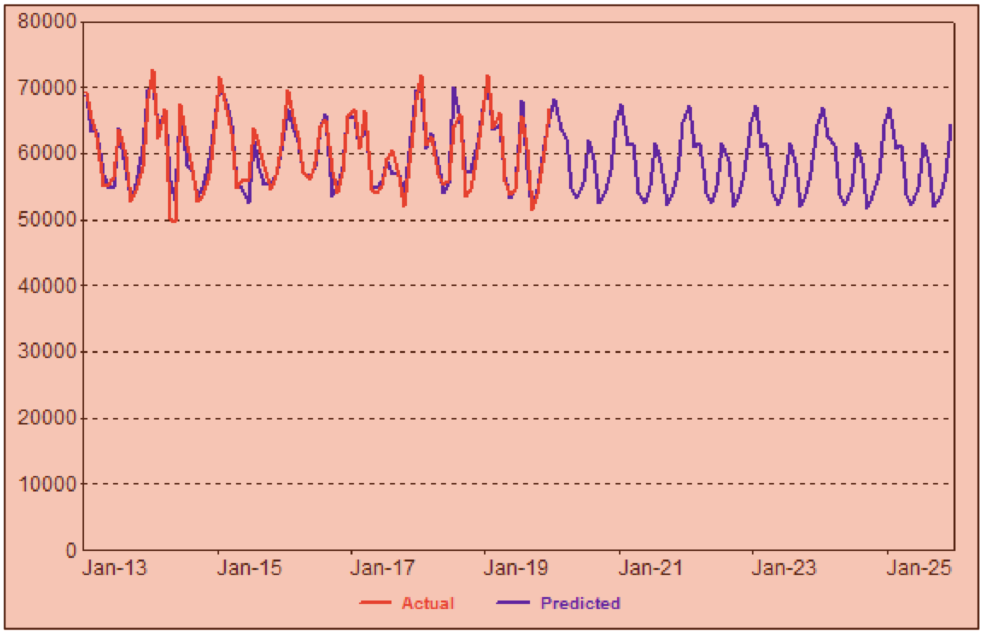


Figure 15: Actual and Predicted GS1000 Sales (MWh)

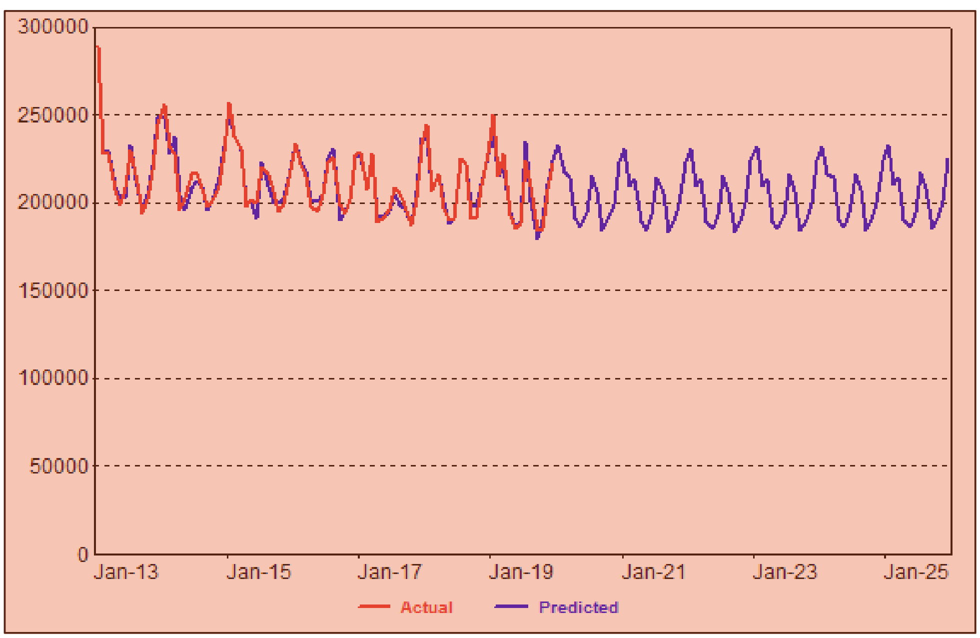
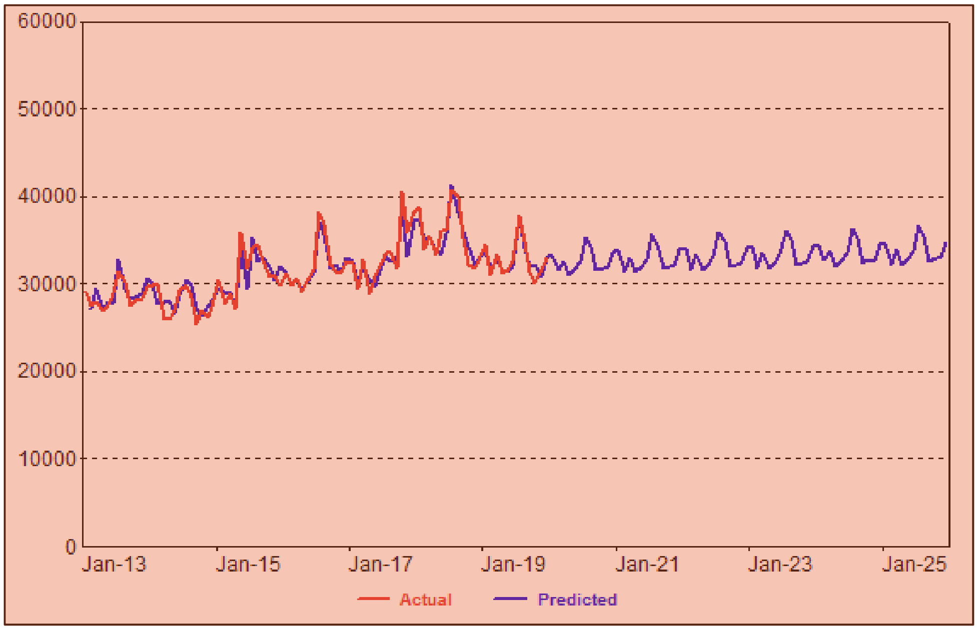
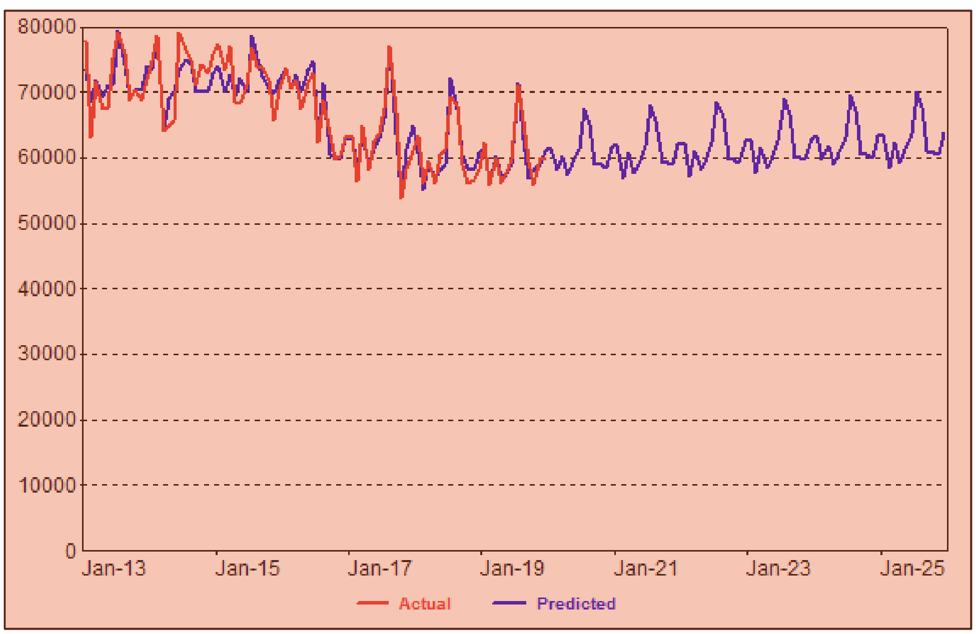


Figure 16: Actual and Predicted GS1500 Sales (MWh)



* Predicted value excludes the impact of CDM, adjustment made outside of model

Figure 17: Actual and Predicted GS5000 Sales (MWh)



* Predicted value excludes the impact of CDM, adjustment made outside of model

Table 6 shows annual commercial sales forecast, adjusted for future CDM.

Table 6: Commercial Sales Forecast

Class Sales Forecast (MWh)								
Year	GS 50	chg	GS 1000	chg	GS 1500	chg	GS 5000	chg
2013	720,479		2,662,723		343,409		857,551	
2014	714,941	-0.8%	2,592,557	-2.6%	333,082	-3.0%	872,269	1.7%
2015	723,755	1.2%	2,574,347	-0.7%	374,916	12.6%	867,663	-0.5%
2016	733,312	1.3%	2,536,560	-1.5%	385,291	2.8%	805,584	-7.2%
2017	712,369	-2.9%	2,473,756	-2.5%	399,393	3.7%	753,196	-6.5%
2018	727,991	2.2%	2,512,017	1.5%	426,660	6.8%	723,849	-3.9%
2019	724,441	-0.5%	2,488,687	-0.9%	392,965	-7.9%	723,018	-0.1%
2020	707,565	-2.3%	2,451,501	-1.5%	386,744	-1.6%	701,742	-2.9%
2021	699,870	-1.1%	2,431,951	-0.8%	385,754	-0.3%	682,921	-2.7%
2022	699,135	-0.1%	2,436,147	0.2%	386,993	0.3%	682,300	-0.1%
2023	697,637	-0.2%	2,440,940	0.2%	388,277	0.3%	682,504	0.0%
2024	697,775	0.0%	2,451,437	0.4%	390,553	0.6%	684,408	0.3%
2025	695,838	-0.3%	2,451,289	0.0%	391,593	0.3%	683,533	-0.1%
2013-19		0.1%		-1.1%		2.5%		-2.7%
2020-25		-0.3%		0.0%		0.2%		-0.5%

Separate models are estimated for commercial customers. GS50 customers are driven by the number of residential customers as the correlation between GS50 customers and residential customers is 0.97. A simple linear trend model is used to forecast customers for the GS1000 rate classes (non-interval and interval-meter classes) as customers have been migrating from non-interval rate class to the interval rate class. There has been no increase in the number of GS1500 and GS5000 customers; customer forecast is held constant at current levels. Table 7 shows the commercial customer forecast.

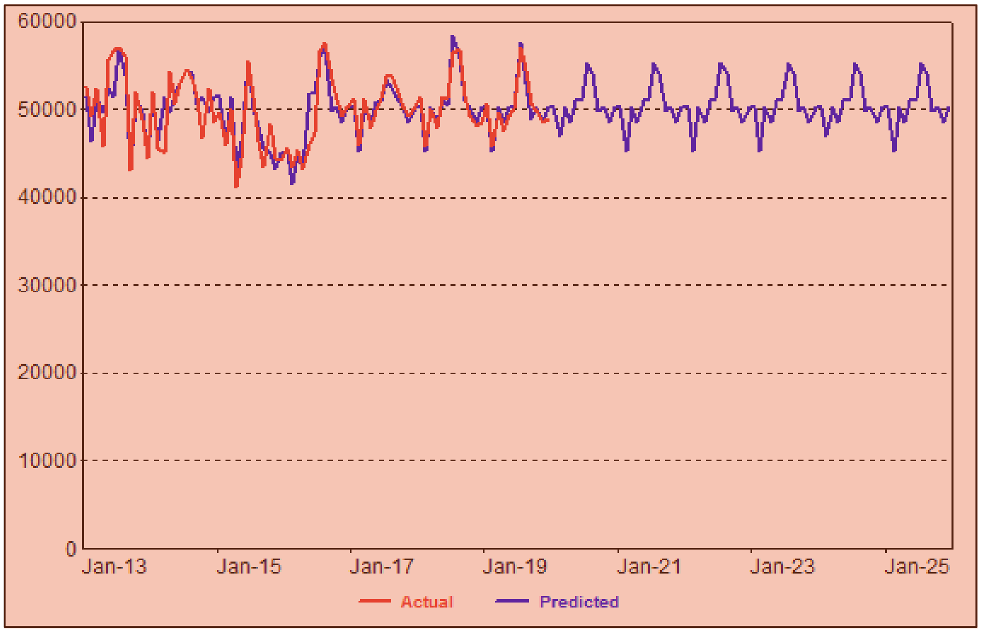
Table 7: Commercial Customer Forecast

Year	GS 50	chg	GS 1000	chg	GS 1500	chg	GS 5000	chg
2013	23,936		3,349		59		76	
2014	23,968	0.1%	3,453	3.1%	61	3.4%	87	14.5%
2015	24,392	1.8%	3,261	-5.6%	65	6.6%	79	-9.2%
2016	24,623	0.9%	3,144	-3.6%	64	-1.5%	72	-8.9%
2017	24,786	0.7%	3,147	0.1%	69	7.8%	74	2.8%
2018	24,926	0.6%	3,152	0.2%	71	2.9%	68	-8.1%
2019	25,030	0.4%	3,112	-1.3%	69	-2.8%	67	-1.5%
2020	25,200	0.7%	3,073	-1.3%	73	5.8%	68	1.5%
2021	25,391	0.8%	3,047	-0.8%	73	0.0%	68	0.0%
2022	25,554	0.6%	3,012	-1.1%	73	0.0%	68	0.0%
2023	25,704	0.6%	2,976	-1.2%	73	0.0%	68	0.0%
2024	25,846	0.6%	2,940	-1.2%	73	0.0%	68	0.0%
2025	25,987	0.5%	2,903	-1.3%	73	0.0%	68	0.0%
2013-19		0.7%		-1.2%		2.7%		-1.7%
2020-25		0.6%		-1.1%		0.0%		0.0%

3.1.3 Other Rate Classes: Large Users, Street Lighting, MU, DCL

Generalized econometric models are estimated for Large Users, as well as the Street Lighting, MU, and DCL. The Large User class includes Hydro Ottawa's eleven largest customers. Large User sales have been relatively constant since 2016. We assume that sales continue at this level over the next five years. Figure 18 shows actual and predicted large user sales.

Figure 18: Actual and Predicted Large Users (MWh)



* Predicted value excludes the impact of CDM, adjustment made outside of model

Street Lighting sales have been declining as part of lamp efficiency improvements. The forecast is derived by holding current street lighting sales constant and then adjusting for expected savings from further CDM street lighting activity. Figure 19 and Figure 20 show model results and forecast adjusted for additional CDM savings projections.

Figure 19: Actual and Predicted Street Light (MWh)

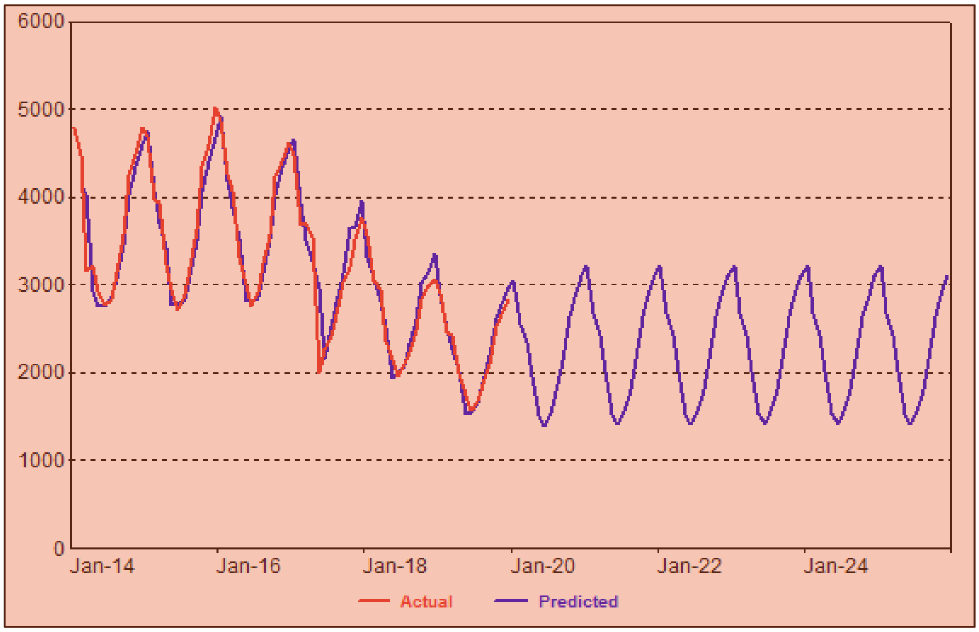
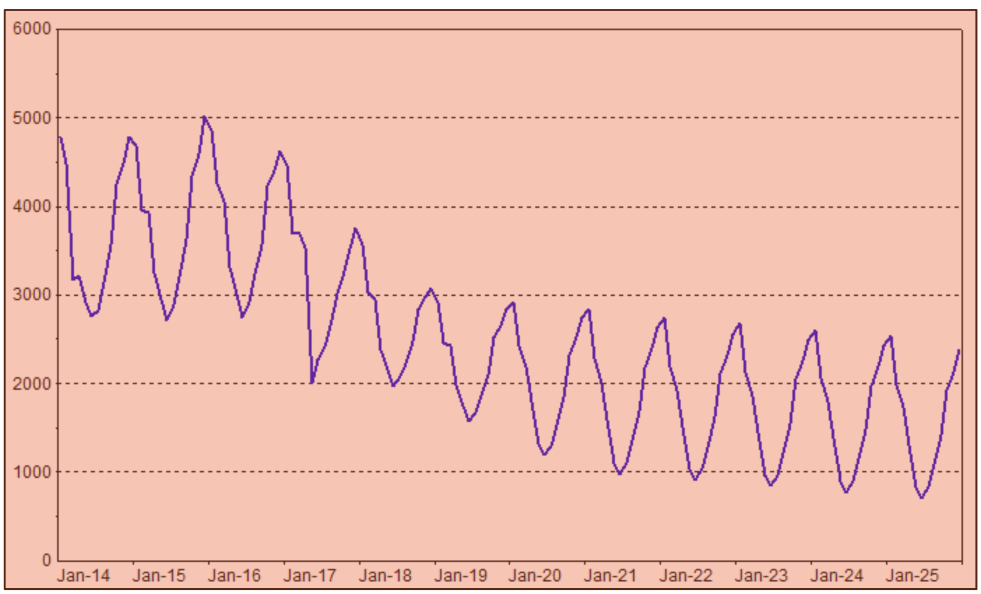


Figure 20: Street Light CDM Adjusted



The MU and DCL classes are both small rate classes with little sales. Given there is little information to explain sales trends, models are estimated with simple exponential smoothing models. The estimated model coefficients and model statistics are included in Appendix A. MU sales are adjusted for future CDM.

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3.1.4 *Billing Demand Forecast*

Several commercial rate classes include billing demand as well as sales and customer forecasts. Billing demand is a measure of a customer's highest hourly demand over the billing period. Monthly billing demand regression models are estimated for each rate class. Demands are modeled as a function of monthly sales and monthly binary variables. The models are estimated with actuals from January 2013 to December 2019. Table 8 shows rate class billing demand forecast.

Table 8: Class Demand Forecast

Class Billing Demand (MW)												
Year	GS 1000 NI	Chg	GS 1000 I	Chg	GS 1500	Chg	GS 5000	Chg	Large Users	Chg	St Light	Chg
2013	387,717		254,033		70,296		191,749		121,622		10,344	
2014	357,675	-7.7%	232,563	-8.5%	65,093	-7.4%	174,815	-8.8%	102,709	-15.6%	10,344	0.0%
2015	357,091	-0.2%	245,936	5.8%	79,880	22.7%	169,512	-3.0%	104,951	2.2%	10,810	4.5%
2016	355,176	-0.5%	264,544	7.6%	85,387	6.9%	165,417	-2.4%	104,754	-0.2%	10,665	-1.3%
2017	324,676	-8.6%	263,462	-0.4%	90,763	6.3%	179,137	8.3%	102,642	-2.0%	9,793	-8.2%
2018	342,355	5.4%	278,914	5.9%	88,992	-2.0%	173,017	-3.4%	104,001	1.3%	7,818	-20.2%
2019	288,388	-15.8%	289,047	3.6%	81,320	-8.6%	155,831	-9.9%	103,877	-0.1%	6,606	-15.5%
2020	274,479	-4.8%	285,282	-1.3%	77,147	-5.1%	142,531	-8.5%	100,489	-3.3%	5,873	-11.1%
2021	264,819	-3.5%	291,205	2.1%	77,120	0.0%	139,884	-1.9%	98,814	-1.7%	5,313	-9.5%
2022	257,330	-2.8%	299,008	2.7%	77,407	0.4%	140,051	0.1%	98,706	-0.1%	4,991	-6.1%
2023	249,962	-2.9%	306,779	2.6%	77,676	0.3%	140,198	0.1%	98,597	-0.1%	4,804	-3.7%
2024	242,511	-3.0%	314,611	2.6%	77,984	0.4%	140,364	0.1%	98,489	-0.1%	4,617	-3.9%
2025	235,832	-2.8%	322,574	2.5%	78,355	0.5%	140,597	0.2%	98,385	-0.1%	4,430	-4.1%
2013-19		-4.6%		2.3%		3.0%		-3.2%		-2.4%		-6.8%
2020-25		-3.0%		2.5%		0.3%		-0.3%		-0.4%		-5.5%

3.1.5 *Adjustments for CDM*

Estimated historical and forecasted CDM savings are directly incorporated into the estimated rate class sales forecast models; cumulative historical CDM are included as a separate model variable. In the residential average use model CDM is on a per customer basis and in the commercial models on a total MWh savings basis.

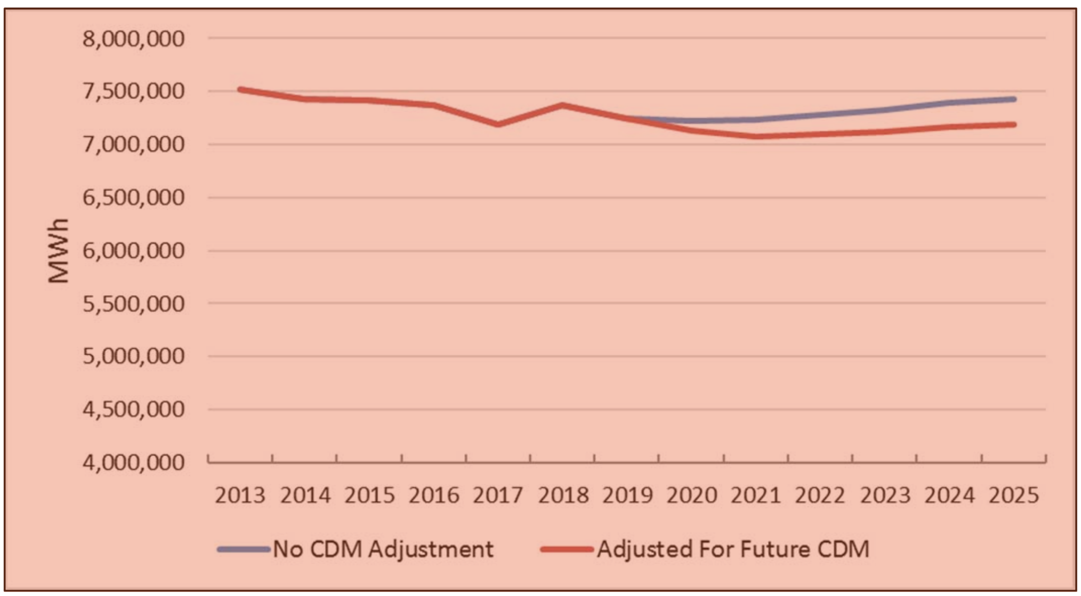
There are two reasons to include CDM as a model variable. First, adding CDM helps explain the declining customer usage and as a result improves on the model fit statistics. Second, it helps avoid double-counting savings. The SAE models already have strong efficiency built into the heating, cooling, and other use model variables; some the end-use improvements are due to CDM activity. The CDM coefficient reflect the CDM savings not already captured in the SAE model structure. If none of the CDM savings were captured by the SAE specification, we would expect the coefficient on CDM to be -1.0. If all the CDM impacts were already captured by the model the coefficient would be close to 0 or statistically insignificant.

In the residential model the CDM coefficient is -0.70. This implies that 30% of the CDM savings is already accounted for in the end-use intensity trends and estimated coefficients on the heating, cooling, and base-use variables. For the forecast period, 70 percent of future DSM savings will flow into the model-based forecast; 30% of remaining CDM savings is captured by the SAE specification. In the small commercial model, the coefficient on CDM is -1.06 and -1.15 in the GS1000 sales forecast model. The coefficients imply that the SAE structured variables are not accounting for CDM program savings. CDM coefficients are actually lower than -1.0 implying that estimates of rate class CDM sales are too low. This may be the result of the CDM allocation process to rate schedules – not enough CDM is allocated to the rate classes. The coefficient on the CDM variable in the GS1500 and GS5000 models are statistically insignificant; CDM was dropped as a model variable.

Sales impact from future CDM savings are derived by executing savings projections through the estimated model where CDM is included as a model variable and treated as in the past (subtracted from the forecast model estimate) for GS1500, GS5000, Street Lighting, and MU.

Figure 21 compares the forecast with and without CDM adjustments. Excluding additional CDM activity, sales are projected to average 0.6% annually between 2020 and 2025. CDM reduces annual sales growth by 0.5% over the next five years to 0.1%.

Figure 21: CDM Forecast Comparison



3.2 System Purchase and Peak Demand Forecast

System purchases are calculated by applying monthly adjustment factors to monthly sales forecast. The adjustment factors capture system losses and any differences in timing between estimated monthly sales and measured system purchases. The monthly adjustment factors are based on the historical relationship between purchases and sales between January 2015 and December 2019. While there is some small monthly variation, the average adjustment factor is 1.03; the sales forecast is adjusted up three percent.

The system peak forecast is derived through a monthly regression model that relates monthly peak demand to heating, cooling, and base load requirements:

$$Peak_m = B_0 + B_1 HeatVar_m + B_2 CoolVar_m + B_3 BaseVar_m + e_m$$

System peak is effectively driven by the purchase sales forecast. The model variables ($HeatVar_m$, $CoolVar_m$, and $BaseVar_m$) incorporate changes in heating, cooling, and base-use energy requirements derived from the rate class sales forecast models as well as peak-day weather conditions. Efficiency impacts on peak are captured through the constructed model variables.

Heating and Cooling Model Variables

The variable *HeatVar*, is derived by combining peak-day HDD (*PkHDD*) with an estimate of monthly heating requirements (*HeatLoad*):

$$HeatVar_m = HeatLoad_m \times PkHDD_m$$

Heatload is derived from the rate class sales forecast models as the product of the coefficient of the XHeat variable times XHeat for normal weather conditions:

$$HeatLoad_m = B_1 \times NrmXHeat_m$$

The peak-day cooling variable is constructed in a similar manner. *CoolVar* is calculated as:

$$CoolVar_m = CoolLoad_m \times PkTDD_m$$

Where

$CoolLoad_m = B_2 \times NrmXCool_m$ (Derived from the estimated rate class models)
PkTDDm = Peak-day THI degree-day

Figure 22 and Figure 23 show the peak model heating and cooling variables.

Figure 22: Peak XHeat Variable

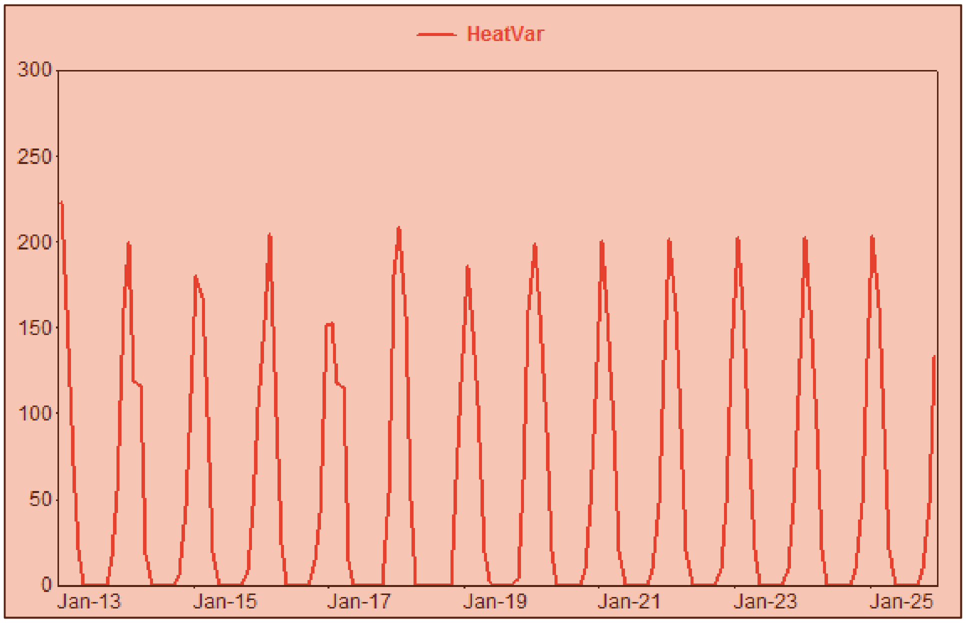
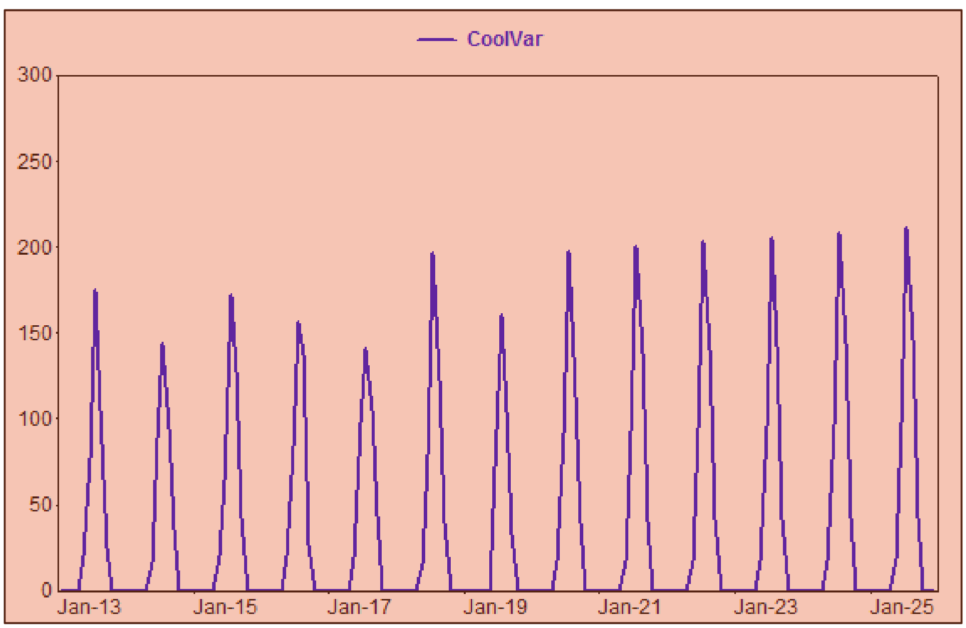


Figure 23: Peak XCool Variable



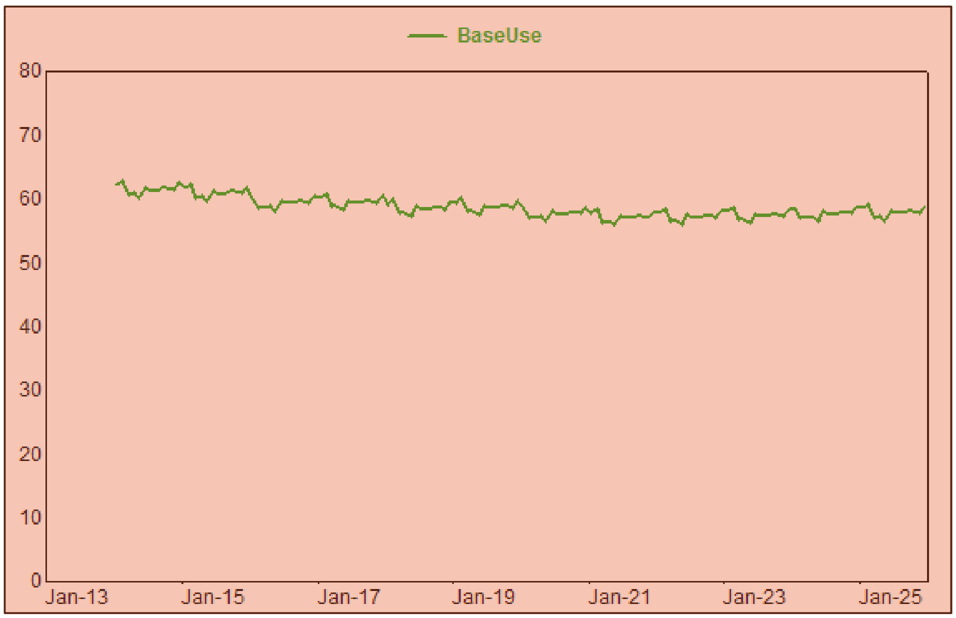
BaseVar Model Variable

BaseVar captures growth in non-weather sensitive usage at the time of the peak. It is again derived from the sales forecast models. BaseVar is calculated by subtracting weather-normal cooling and heating load requirements from weather normal total purchases and forecast.

$BaseVar_m = WNSales_m – HeatLoad_m - CoolLoad_m$

BaseVar is expressed on an average monthly MW basis by dividing *BaseVar* by the number of hours in the month. Figure 24 shows the derived model variable *BaseVar*.

Figure 24: Peak Base Variable



In addition to the end-use variables, the peak model includes monthly binaries for several months to account for non-weather seasonal changes in demand and a shift variable to account for increase in demand after 2016. The model explains past variation relatively well with an adjusted R-squared is 0.87 with a MAPE of 2.9%. Model statistics are included in Appendix A. Figure 25 shows actual and predicted monthly system peak.

Figure 25: Actual and Predicted Peak Model (MW)

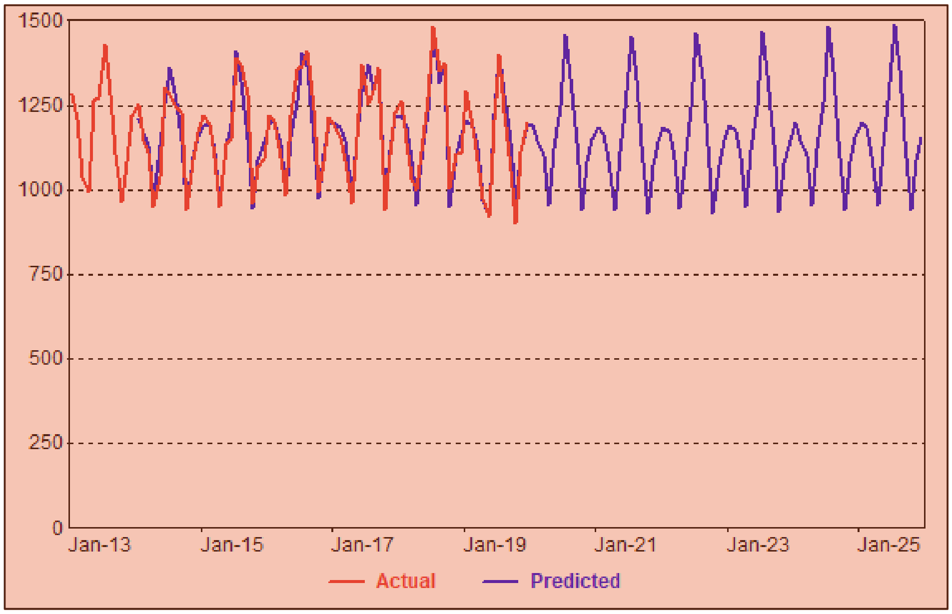


Table 9 shows system purchase and peak demand forecast.

Table 9: System Forecast

Year	System Purchases (MWh)	chg	Peak Demand (MW)	chg
2013	7,722,175		1,427	
2014	7,636,154	-1.1%	1,304	-8.6%
2015	7,622,794	-0.2%	1,392	6.7%
2016	7,600,820	-0.3%	1,407	1.1%
2017	7,410,784	-2.5%	1,369	-2.7%
2018	7,612,656	2.7%	1,481	8.2%
2019	7,458,493	-2.0%	1,398	-5.6%
2020	7,353,252	-1.4%	1,458	4.3%
2021	7,285,713	-0.9%	1,452	-0.4%
2022	7,308,596	0.3%	1,460	0.6%
2023	7,337,656	0.4%	1,468	0.5%
2024	7,387,271	0.7%	1,480	0.8%
2025	7,402,111	0.2%	1,487	0.5%
2013-19		-0.6%		-0.2%
2020-25		0.1%		0.4%

4 Appendix A: Model Statistics

System Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mEndUse.BaseUse	17.35	0.31	56.30	0.00%
mPkVars.HeatVar	0.65	0.14	4.65	0.00%
mPkVars.CoolVar	2.07	0.17	12.27	0.00%
mBin.Yr2016Plus	50.11	12.33	4.07	0.01%
mBin.Apr	-102.40	25.47	-4.02	0.02%
mBin.May	53.22	26.62	2.00	4.99%
mBin.Oct	-123.02	26.42	-4.66	0.00%
mBin.Sep17	181.96	51.28	3.55	0.07%
mBin.Sep18	223.46	51.31	4.36	0.01%
mBin.May19	-180.40	54.57	-3.31	0.16%

Model Statistics	
Adjusted Observations	72
Deg. of Freedom for Error	62
Adjusted R-Squared	0.873
Model Sum of Squares	1,217,662.51
Sum of Squared Errors	152,068.28
Mean Squared Error	2,452.71
Std. Error of Regression	49.52
Mean Abs. Dev. (MAD)	34.26
Mean Abs. % Err. (MAPE)	2.92%
Durbin-Watson Statistic	1.923

Residential Avg Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRev.XHeatRes_AvgUse	0.68	0.0	32.19	0.00%
mStructRev.XCoolRes_AvgUse	0.52	0.0	33.46	0.00%
mStructRev.XOtherRes_AvgUse	1.03	0.0	90.38	0.00%
mBin.Mar	-30.03	7.1	-4.20	0.01%
mBin.Apr	-24.42	7.2	-3.39	0.11%
mBin.May	-33.44	7.5	-4.47	0.00%
mBin.Nov	-21.04	7.1	-2.98	0.39%
mBin.Yr15	-18.58	5.7	-3.25	0.18%
mBin.Yr16	-17.23	5.5	-3.14	0.25%
CDM.ResCDM_PC	-0.70	0.1	-5.93	0.00%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	74
Adjusted R-Squared	0.964
Model Sum of Squares	652,097
Sum of Squared Errors	21,518
Mean Squared Error	291
Std. Error of Regression	17.05
Mean Abs. Dev. (MAD)	12.41
Mean Abs. % Err. (MAPE)	2.0%
Durbin-Watson Statistic	2.227

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Economics.Pop	6.45	2.35	2.75	0.77%
Res_Custs.LagDep(1)	0.96	0.02	64.20	0.00%
mBin.Jul14Plus	196.46	84.06	2.34	2.23%
mBin.Jan	4749.69	1322.28	3.59	0.06%
mBin.Feb	4498.44	1326.30	3.39	0.12%
mBin.Mar	4465.29	1326.57	3.37	0.13%
mBin.Apr	4480.07	1326.37	3.38	0.12%
mBin.May	4500.40	1326.39	3.39	0.12%
mBin.Jun	4608.76	1326.60	3.47	0.09%
mBin.Jul	4490.57	1317.53	3.41	0.11%
mBin.Aug	4570.91	1317.90	3.47	0.09%
mBin.Sep	4617.43	1319.24	3.50	0.08%
mBin.Oct	4727.68	1321.16	3.58	0.06%
mBin.Nov	4726.71	1324.49	3.57	0.07%
mBin.Dec	4634.61	1327.77	3.49	0.08%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	69
Adjusted R-Squared	1
Model Sum of Squares	5,556,180,667.56
Sum of Squared Errors	1,198,806.39
Mean Squared Error	17,374.01
Std. Error of Regression	131.81
Mean Abs. Dev. (MAD)	89.55
Mean Abs. % Err. (MAPE)	0.03%
Durbin-Watson Statistic	1.948

GS 50 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	20382.41	7266.7	2.81	0.63%
mStructRev.XOtherGS50	2597.19	609.3	4.26	0.01%
mStructRev.XHeatGS50	181414.90	7411.4	24.48	0.00%
mStructRev.XCoolGS50	23330.92	1510.4	15.45	0.00%
mBin.Jun14	10458.85	2004.9	5.22	0.00%
CDM.GS50	-1.06	0.4	-2.81	0.63%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	78
Adjusted R-Squared	0.882
Model Sum of Squares	2,382,118,228
Sum of Squared Errors	298,386,024
Mean Squared Error	3,825,462
Std. Error of Regression	1,955.88
Mean Abs. Dev. (MAD)	1,413.07
Mean Abs. % Err. (MAPE)	2.37%
Durbin-Watson Statistic	1.706

GS 50 Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	9766.86	1964.53	4.97	0.00%
Res_Custs.Predicted	0.05	0.01	7.60	0.00%
AR(1)	0.93	0.04	22.36	0.00%

Model Statistics	
Adjusted Observations	83
Deg. of Freedom for Error	80
Adjusted R-Squared	0.993
Model Sum of Squares	14,075,934.34
Sum of Squared Errors	102,395.61
Mean Squared Error	1,279.95
Std. Error of Regression	35.78
Mean Abs. Dev. (MAD)	23.4
Mean Abs. % Err. (MAPE)	0.10%
Durbin-Watson Statistic	1.568

GS 1000 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	80136.99	17663.86	4.54	0.00%
mStructRev.XOtherGS1000	9652.91	1482.07	6.51	0.00%
mStructRev.XHeatGS1000	561587.66	18363.77	30.58	0.00%
mStructRev.XCoolGS1000	75654.60	3994.26	18.94	0.00%
mBin.Jan13	41155.31	4954.61	8.31	0.00%
mBin.Jul18	-15259.29	5327.04	-2.86	0.54%
CDM.GS1000	-1.151	0.102	-11.33	0.00%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	77
Adjusted R-Squared	0.939
Model Sum of Squares	28,636,815,421
Sum of Squared Errors	1,710,831,503
Mean Squared Error	22,218,591
Std. Error of Regression	4,713.66
Mean Abs. Dev. (MAD)	3,492.57
Mean Abs. % Err. (MAPE)	1.65%
Durbin-Watson Statistic	1.896

GS 1000 NI Share Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.TrendVar	-0.02	0.00	-29.25	0.00%
mBin.Jan	0.58	0.00	171.29	0.00%
mBin.Feb	0.58	0.00	166.41	0.00%
mBin.Mar	0.57	0.00	168.32	0.00%
mBin.Apr	0.56	0.00	178.96	0.00%
mBin.May	0.53	0.00	171.83	0.00%
mBin.Jun	0.532	0.003	170.56	0.00%
mBin.Jul	0.538	0.003	171.69	0.00%
mBin.Aug	0.54	0.003	171.67	0.00%
mBin.Sep	0.537	0.003	169.72	0.00%
mBin.Oct	0.539	0.003	169.65	0.00%
mBin.Nov	0.559	0.003	175.2	0.00%
mBin.Dec	0.571	0.003	177.98	0.00%
mBin.Feb14	-0.027	0.008	-3.252	0.18%
mBin.Mar14	0.046	0.008	5.487	0.00%
AR(1)	0.23	0.094	2.453	1.68%

Model Statistics	
Adjusted Observations	83
Deg. of Freedom for Error	67
Adjusted R-Squared	0.961
Model Sum of Squares	0.1
Sum of Squared Errors	0.0
Mean Squared Error	0.0
Std. Error of Regression	0.01
Mean Abs. Dev. (MAD)	0.01
Mean Abs. % Err. (MAPE)	1.09%
Durbin-Watson Statistic	1.434

GS 1000NI Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	2491.26	34.71	71.78	0.00%
mBin.TrendVar	-74.39	10.18	-7.31	0.00%
AR(1)	0.82	0.09	9.51	0.00%

Model Statistics	
Adjusted Observations	54
Deg. of Freedom for Error	51
Adjusted R-Squared	0.97
Model Sum of Squares	414,816.10
Sum of Squared Errors	12,541.16
Mean Squared Error	245.91
Std. Error of Regression	15.68
Mean Abs. Dev. (MAD)	9.26
Mean Abs. % Err. (MAPE)	0.41%
Durbin-Watson Statistic	1.823

GS 1000I Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-3172.986	279.85	-11.34	0.00%
mFcstRev.ResCust	0.01	0.00	14.40	0.00%
AR(1)	0.92	0.04	24.61	0.00%
MA(1)	0.11	0.12	0.94	34.81%

Model Statistics	
Adjusted Observations	83
Deg. of Freedom for Error	79
Adjusted R-Squared	0.998
Model Sum of Squares	910,448.76
Sum of Squared Errors	1,676.22
Mean Squared Error	21.22
Std. Error of Regression	4.61
Mean Abs. Dev. (MAD)	3.22
Mean Abs. % Err. (MAPE)	0.42%
Durbin-Watson Statistic	1.894

GS 1500 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	8885.19	3266.36	2.72	0.81%
mStructRev.XOtherGS1500	1660.96	249.75	6.65	0.00%
mStructRev.XHeatGS1500	29249.46	6591.04	4.44	0.00%
mStructRev.XCoolGS1500	8492.33	893.14	9.51	0.00%
mBin.Mar14	-4111.28	943.79	-4.36	0.00%
mBin.May15	5271.47	925.22	5.70	0.00%
mBin.Oct17	7472.773	938.51	7.962	0.00%
mBin.Jul16	2994.113	916.03	3.269	0.16%
AR(1)	0.86	0.057	14.973	0.00%

Model Statistics	
Adjusted Observations	83
Deg. of Freedom for Error	74
Adjusted R-Squared	0.881
Model Sum of Squares	900,271,730
Sum of Squared Errors	108,433,567
Mean Squared Error	1,465,318
Std. Error of Regression	1210.5
Mean Abs. Dev. (MAD)	895.09
Mean Abs. % Err. (MAPE)	2.84%
Durbin-Watson Statistic	2.168

GS 1500 Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1.025	0.112	9.184	0.00%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	83
Adjusted R-Squared	0.931
Model Sum of Squares	1,651.00
Sum of Squared Errors	123.00
Mean Squared Error	1.48
Std. Error of Regression	1.22
Mean Abs. Dev. (MAD)	0.57
Mean Abs. % Err. (MAPE)	0.86%
Durbin-Watson Statistic	1.967

GS 5000 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	26059.541	9867.5	2.641	1.01%
mStructRev.XHeatGS5000	45535.968	9552.44	4.77	0.00%
mStructRev.XCoolGS5000	19727.169	1962.05	10.05	0.00%
mStructRev.XOtherGS5000	3461.75	801.32	4.32	0.01%
mBin.Feb14	10058.94	2655.34	3.79	0.03%
mBin.Mar14	-8603.04	2503.84	-3.44	0.10%
mBin.Jul16	-7481.19	2620.44	-2.86	0.56%
mBin.Aug17	12618.43	2550.65	4.95	0.00%
mBin.Oct17	-6873.21	2576.92	-2.67	0.94%
mBin.Jul16Plus	-10852.56	777.70	-13.96	0.00%
mBin.Yr18Plus	-3991.207	852.88	-4.68	0.00%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	73
Adjusted R-Squared	0.879
Model Sum of Squares	3,661,854,724
Sum of Squared Errors	436,230,761
Mean Squared Error	5,975,764
Std. Error of Regression	2,444.54
Mean Abs. Dev. (MAD)	1,785.11
Mean Abs. % Err. (MAPE)	2.66%
Durbin-Watson Statistic	1.834

GS 5000 Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.997	0.11	9.083	0

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	83
Adjusted R-Squared	0.847
Model Sum of Squares	3,959.00
Sum of Squared Errors	716.00
Mean Squared Error	8.63
Std. Error of Regression	2.94
Mean Abs. Dev. (MAD)	1.41
Mean Abs. % Err. (MAPE)	1.98%
Durbin-Watson Statistic	2

Large Users Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Days	1655.96	13.67	121.14	0.00%
mWthr.wgtCDD18GSLrg	50.07	5.87	8.53	0.00%
mBin.Sep13	-7191.25	2048.95	-3.51	0.08%
mBin.Dec13	-6907.52	2053.83	-3.36	0.12%
mBin.Jun15	11164.32	2091.72	5.34	0.00%
mBin.Apr15Plus	-6446.02	706.66	-9.12	0.00%
mBin.May16Plus	5261.803	656.01	8.021	0.00%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	77
Adjusted R-Squared	0.729
Model Sum of Squares	927,196,200
Sum of Squared Errors	310,976,768
Mean Squared Error	4,038,659
Std. Error of Regression	2009.64
Mean Abs. Dev. (MAD)	1332.49
Mean Abs. % Err. (MAPE)	2.70%
Durbin-Watson Statistic	1.984

Large Users Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1	0.11	9.11	0

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	83
Adjusted R-Squared	0.84
Model Sum of Squares	63.00
Sum of Squared Errors	12.00
Mean Squared Error	0.00
Std. Error of Regression	0
Mean Abs. Dev. (MAD)	0
Mean Abs. % Err. (MAPE)	0.80%
Durbin-Watson Statistic	2

Street Lighting Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	4468.41	174.03	25.68	0.00%
mBin.Feb	3924.47	166.49	23.57	0.00%
mBin.Mar	3666.68	161.70	22.68	0.00%
mBin.Apr	3257.07	158.49	20.55	0.00%
mBin.May	2781.26	156.28	17.80	0.00%
mBin.Jun	2662.88	154.74	17.21	0.00%
mBin.Jul	2789.984	153.677	18.155	0.00%
mBin.Aug	3046.127	152.936	19.918	0.00%
mBin.Sep	3389.354	152.422	22.237	0.00%
mBin.Oct	3889.112	152.064	25.576	0.00%
mBin.Nov	4103.446	151.814	27.029	0.00%
mBin.Dec	4347.237	151.64	28.668	0.00%
mBin.Yr18	-760.712	189.338	-4.018	0.02%
mBin.Yr19Plus	-1242.28	221.828	-5.6	0.00%
AR(1)	0.665	0.107	6.195	0.00%

Model Statistics	
Adjusted Observations	71
Deg. of Freedom for Error	56
Adjusted R-Squared	0.915
Model Sum of Squares	49,906,946
Sum of Squared Errors	3,637,633
Mean Squared Error	64,958
Std. Error of Regression	254.87
Mean Abs. Dev. (MAD)	162.09
Mean Abs. % Err. (MAPE)	5.30%
Durbin-Watson Statistic	2.306

Street Lighting Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1.111	0.121	9.166	0
Trend	0.021	0.033	0.635	0.527

Model Statistics	
Adjusted Observations	72
Deg. of Freedom for Error	70
Adjusted R-Squared	0.986
Model Sum of Squares	207,768,439.00
Sum of Squared Errors	2,838,162.00
Mean Squared Error	40,545.17
Std. Error of Regression	201.36
Mean Abs. Dev. (MAD)	116.28
Mean Abs. % Err. (MAPE)	0.20%
Durbin-Watson Statistic	1.954

MU Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.14	0.042	3.318	0.10%
Trend	-0.046	0.01	-7.79	0.00%
Seasonal	0.839	0.111	7.575	0.00%

Model Statistics	
Adjusted Observations	120
Deg. of Freedom for Error	117
Adjusted R-Squared	0.828
Model Sum of Squares	1,143,603
Sum of Squared Errors	233,124
Mean Squared Error	1,993
Std. Error of Regression	45
Mean Abs. Dev. (MAD)	33
Mean Abs. % Err. (MAPE)	2.37%
Durbin-Watson Statistic	2.375

MU Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1.037	0.11	9.452	0

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	83
Adjusted R-Squared	0.752
Model Sum of Squares	81,628.00
Sum of Squared Errors	26,963.00
Mean Squared Error	324.86
Std. Error of Regression	18.02
Mean Abs. Dev. (MAD)	5.95
Mean Abs. % Err. (MAPE)	0.18%
Durbin-Watson Statistic	2.007

DCL Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	1	0.119	8.426	0.00%

Model Statistics	
Adjusted Observations	72
Deg. of Freedom for Error	71
Adjusted R-Squared	0.945
Model Sum of Squares	16,210
Sum of Squared Errors	949
Mean Squared Error	13
Std. Error of Regression	4
Mean Abs. Dev. (MAD)	1
Mean Abs. % Err. (MAPE)	0.29%
Durbin-Watson Statistic	2

INTERROGATORY RESPONSE - VECC-50

3.0-VECC-50

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, page 1

SUBJECT AREA: Load Forecast

Preamble:

The Application states: "*Hydro Ottawa has adjusted Itron's load forecast to include Sentinel Lights and Standby Power, as these were not forecasted separately by Itron*".

a) Please explain how the Standby Power class' forecast customer count and demand sales for the years 2021-2025 were derived and provide all supporting models/input data.

b) Why are there no kWh sales attributed to Standby Power?

c) Please explain how the Sentinel Lights class' forecast connection count, energy sales and demand sales for the years 2021-2025 were derived and provide all supporting models/input data.

RESPONSE:

a) Historical values indicated there was a consistent number of customers and demand sales for the Standby Power class. Hydro Ottawa is also aware of a future Standby customer, therefore the forecast has been adjusted for this known variable.

b) Standby Power is only billed by demand, hence the absence of any attributed kWh sales.

c) Historical values indicated there was a consistent value in Sentinel Lights customer count, energy sales, and demand sales. Sentinel Lights were therefore given a flat value across all years.

INTERROGATORY RESPONSE - VECC-51

3.0-VECC-51

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, page 4 (Tables 3 & 4)

SUBJECT AREA: Load Forecast

Preamble:

Tables 3 and 4 provide the average number of customers/connection by customer class for each of the test years.

a) Please explain how the "averages" were derived (e.g., are they the average of the 12 monthly values).

RESPONSE:

a) The average is calculated as the average of the 12 monthly values for each year.

INTERROGATORY RESPONSE - VECC-52

3.0-VECC-52

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, page 4

Updated Exhibit 8, Tab 1, Schedule 1, page 9

SUBJECT AREA: Load Forecast

Preamble:

In Updated Exhibit 3, the Application states: "*As of November 1, 2025, the TOC will be discontinued for all customers*".

In Updated Exhibit 8, the Application states:

> *Effective April 1, 2015, customers with customer-owned transformers installed after November 1, 2000 were no longer eligible to receive the credit. The TOC will be discontinued for customers who own transformers that were installed prior to November 1, 2000 either when the customer-owned transformer has been replaced, or after November 1, 2025 – whichever occurs first.*

a) Please explain how the 2021-2025 demand sales forecast for the transformer ownership credit provided in Table 5 (Updated) were derived and provide all supporting models/input data.

b) Does the 2021-2024 demand sales forecast for the transformer ownership credit provided in Table 5 represent: i) the forecast demand attributable to all customers with customer-owned transformers or ii) the forecast demand attributable to customers with customer owned transformers installed prior to November 1, 2000? If neither, what do the values represent?

c) If not provided in Table 5 (Updated), for each of the years 2020-2024 please provide the demand sales forecast for all customers with customer-owned transformers.

d) If not provided in Table 5 (Updated), for each of the years 2020-2024 please provide the forecast demand attributable to customers with customer owned transformers installed prior to November 1, 2000.

e) Does the 2025 demand sales forecast for the transformer ownership credit provided in Table 5 (Updated) represent i) the forecast demand attributable to all customers with customer-owned transformers for the first 10 months of the year or ii) the forecast demand attributable to customers with customer owned transformers installed prior to November 1, 2000 for the first 10 months of 2025? If neither, what do the values represent?

f) If not provided in Table 5 (Updated), please provide for 2025 the demand sales forecast for all customers with customer-owned transformers.

RESPONSE:

a) The 2021-2025 demand sales forecast for the transformer ownership credit ("TOC") provided in Table 5 (UPDATED) were derived based on historical trending. Hydro Ottawa estimates the kW eligible for the TOC at 25% of the total monthly sales demand for the General Service 50 to 1,000 kW Non-Interval to the Large User class. The total TOC forecast demand was then allocated to the rate classes based on percentages derived from 2019 actual credits paid. Please see excel Attachment VECC-52(A): Transformer Ownership Credit Sales Demand - kW Forecast for full details of the calculation.

b) Hydro Ottawa has not removed the TOC for those customers that were receiving the credit prior to April 1, 2015, with the exception of situations in which Hydro Ottawa has since replaced the transformer and the customer no longer owns it. In addition, Hydro

Ottawa has generally not provided the TOC to new customers who own their transformer after April 1, 2015. The 2021-2024 demand sales forecast for the TOC provided in Table 5 represents the forecast demand attributable to customers described above.

c) Hydro Ottawa is unable to provide a demand sales forecast for all customer-owned transformers. With the current underlying data not easily available, Hydro Ottawa cannot identify all customers who own their transformers and who are not receiving the credit.

d) Hydro Ottawa confirms that the forecast in Table 5 includes demand attributable to customers with customer-owned transformers installed prior to November 1, 2000.

e) The 2025 demand sales forecast for the TOC provided in Table 5 (UPDATED) represents the forecast demand attributable to customers currently receiving the TOC. The table should have only represented the first 10 months of 2025. However, upon review Hydro Ottawa discovered that a full year of forecast demand for the TOC was included in this table. Accordingly, the version of Table 5 that was UPDATED as part of 2019 actuals (i.e. as part of the May 5, 2020 filing from Hydro Ottawa) has been revised below to only include the forecast demand for TOC customers from January through October 2025.

This error did not impact the calculated revenue amount or proposed revenue requirement.

Table 5 – UPDATED FOR 2019 ACTUALS – 2021-2025 Demand Sales Forecast (kW) for Transformer Ownership Credit

	2021	2022	2023	2024	2025
General Service 50 to 1,000 kW Non Interval	309,711	309,680	309,768	310,497	310,085
General Service 50 to 1,000 kW Interval	100,891	100,881	100,909	101,147	101,012
General Service 1,000 to 1,499 kW	351,945	351,909	352,010	352,837	352,369
General Service 1,500 to 4,999 kW	882,208	882,119	882,371	884,445	883,272
Large Use	701,543	701,472	701,673	703,322	702,389
TOTAL KW DEMAND SALES	**2,346,299**	**2,346,060**	**2,346,731**	**2,352,247**	**2,349,128**

Table 5 – UPDATED FOR 2019 ACTUALS – AS REVISED – 2021-2025 Demand Sales Forecast (kW) for Transformer Ownership Credit

	2021	2022	2023	2024	2025
General Service 50 to 1,000 kW Non Interval	309,711	309,680	309,768	310,497	260,011
General Service 50 to 1,000 kW Interval	100,891	100,881	100,909	101,147	84,700
General Service 1,000 to 1,499 kW	351,945	351,909	352,010	352,837	295,467
General Service 1,500 to 4,999 kW	882,208	882,119	882,371	884,445	740,636
Large Use	701,543	701,472	701,673	703,322	588,963
TOTAL KW DEMAND SALES	**2,346,299**	**2,346,060**	**2,346,731**	**2,352,247**	**1,969,778**

f) Please see the response to part (c) above.

INTERROGATORY RESPONSE - VECC-53

3.0-VECC-53

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, pages 2 and 4-5

SUBJECT AREA: Load Forecast

Preamble:

At page 2 the Application states: "*system purchases are derived by applying an average loss factor to rate-class sales forecast*".

a) Please provide the derivation of the system purchase forecast values for 2020-2025 as set out in Table 2 and include all supporting models and input data.

b) At page 4 the Application states that the rate class regression models were estimated using data for the period January 2013 to December 2019. However, on page 5, the Application states that average monthly loss factors were based on the relationship between purchases and retail sales over the four year period 2015-2018. Please explain why the 2015-2018 period was used.

c) If not provided in the response to part (a), please provide the loss factors used and their derivation.

d) How would the loss factors and the resulting forecast of system purchases for 2021-2025 change if the period 2013-2019 was used to estimate the loss factors?

RESPONSE:

a) Please see Attachment VECC-53(A): Loss Derivation.

b) The period 2015-2018 was selected, as the relationship between sales and purchases was relatively consistent. Prior to 2015, this was not always the case, as reported monthly sales included months in which sales were greater than system purchases. Itron excluded 2019, as at the time of the forecast Itron did not have purchase data for all months.

c) Please see Attachment VECC-53(A): Loss Derivation.

d) Please see Attachment VECC-53(A): Loss Derivation.

INTERROGATORY RESPONSE - VECC-54

3.0-VECC-54

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, pages 4-5

EB-2015-0004, Exhibit C, Attachment C1 (A), page 32

SUBJECT AREA: Load Forecast

a) In HOL's last Application (EB-2015-0004), a separate forecast for total system purchases and sales was developed and the results of the individual class sales forecasts were used to allocate the total sales forecast to customer classes. Why wasn't a similar approach used in the current Application?

RESPONSE:

a) The top-down forecast approach was used in the prior application because of issues with the class-level monthly billed sales data. The resulting class-level models were not as statistically strong as desired. Improvements in the billing data over the last three years allowed Itron to estimate much stronger class-level forecast models. With increased confidence in the class models, Itron can use a bottom-up approach (aggregation of class sales to total sales, and then adjustment for losses) to generate a reasonable purchase sales forecast.

INTERROGATORY RESPONSE - VECC-55

3.0-VECC-55

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 5

SUBJECT AREA: Load Forecast

Reference: Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 5

Preamble:

The Application states: "*Normal monthly degree-days are calculated as an average of monthly degree-days over the past twenty years – 1999 through 2018*".

The Application also states:

"Monthly peak-day HDD and TDD (temperature-humidity based degree-days) are used in forecasting peak demand. Peak-day degree-days are based on the average daily temperature and dew point that occurs on the day of the monthly peak. TDD is a two-day weighted temperature as we found prior-day temperature has a significant impact on demand. The weights are 55% for the day of the peak and 45% for the day prior to the peak."

The Board's Chapter 2 Filing Requirements (section 2.3.1.1) require that Applicants provide:

- *Explanation of the weather-normalization methodology proposed including:*
    - *If monthly Heating Degree Days (HDD) and/or Cooling Degree Days (CDD) are used to determine normal weather, the monthly HDD and CDD based on: a) 10-year average and b) a trend based on 20-years. If the applicant proposes an alternative approach, it must be supported.*
    - *Definitions of HDD and CDD, including:*

        - *Climatological measurement point(s) (i.e. identification of Environment Canada weather station(s)) and why these are appropriate for the distributor's service territory*
        - *Identification of base degrees from which HDDs and CDDs are measured (e.g. 18° C or other)*
    - *In addition to the proposed test year load forecast, the load forecasts based on 10-year average and 20-year trends in HDD and CDD*
    - *Rationale to support the weather-normalization methodology chosen*

a) Why was a 20 year time frame used to determine "normal monthly degree days"?

b) With respect to the third bullet, please provide load forecasts for the test year based on 10 year average and 20-year trends HDD and CDD as required or indicate where in the Application this information is already filed.

c) With respect to the peak day forecast methodology, for the 20 year period used in the analysis, in how many months did the actual peak demand for the month occur on the day with the highest HDD/weighted TDD value?

RESPONSE:

a) Please see the response to part (c) of interrogatory OEB-138.

b) Please see the response to interrogatory OEB-3, Attachment OEB-137(A): 10-Year Average 2009-2018, and Attachment OEB-137(B): 20-Year Trended Normal.

c) Peak dates were only available beginning in 2003. Based on the 17 years of data (2003-2019), the annual winter peak coincided with the highest daily HDD value on seven occasions. The summer peak coincided with the highest daily weighted TDD value on seven occasions. It is common for the peak to not occur on the extreme weather days, as those days may fall on a weekend or holiday. Additionally, there can be a build-up effect of heat or cold where peaks occur the day following extreme weather.

INTERROGATORY RESPONSE - VECC-56

3.0-VECC-56

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 7

SUBJECT AREA: Load Forecast

a) With respect to Table 3, for which years are the values provided actual versus forecast?

b) If not provided in Table 3, are the actual values for 2019 now available and, if so, please provide.

RESPONSE:

a) The economic forecast is from Fall 2019. Part of the year would be estimated actual, while the other part would be a forecast. Measures of economic activity (e.g. GDP, employment, personal income) are estimated from surveys on economic activity. It is not unusual for historical estimates to change as new economic and demographic data become available.

b) Table A below provides an updated version of Table 3 that includes actual values for 2019.

Table A – Ottawa Regional Economic Forecast

Year	Population (000's)	Change	GDP ($000,000)	Change	RPI ($000,000)	Change	Employment (000's)	Change
2013	1,315		$70,054		$50,267		695.1	
2014	1,327	0.9%	$70,945	1.3%	$49,770	(1.0)%	706.7	1.7%
2015	1,337	0.8%	$72,397	2.0%	$51,003	2.5%	710.7	0.6%
2016	1,358	1.5%	$74,069	2.3%	$51,985	1.9%	718.8	1.1%
2017	1,385	2.0%	$76,422	3.2%	$54,727	5.3%	726.7	1.1%
2018	1,411	1.9%	$78,793	3.1%	$55,969	2.3%	740.6	1.9%
2019	1,441	2.1%	$80,775	2.5%	$57,315	2.4%	772.5	4.3%
2020	1,463	1.5%	$78,983	-2.2%	$58,252	1.6%	757.4	-2.0%
2021	1,481	1.2%	$82,710	4.7%	$60,105	3.2%	799.3	5.5%
2022	1,498	1.2%	$84,565	2.2%	$61,505	2.3%	819.7	2.5%
2023	1,515	1.1%	$86,012	1.7%	$63,059	2.5%	835.2	1.9%
2024	1,532	1.1%	$87,594	1.8%	$64,650	2.5%	853.0	2.1%
2025	1,549	1.1%	$89,097	1.7%	$66,202	2.4%	870.3	2.0%
2013-19		**1.5%**		**2.4%**		**2.2%**		**1.8%**
2019-25		**1.2%**		**1.7%**		**2.4%**		**2.0%**

INTERROGATORY RESPONSE - VECC-57

3.0-VECC-57

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, pages 11 and 18

Updated Exhibit 8, Tab 1, Schedule 1, page 2 and Tab 10

SUBJECT AREA: Load Forecast

Preamble:

At Attachment C, page 18 the Application states:

"*Since 2013, GS1000 customers have been migrating to interval metering; interval metered customers (GS1000I) are priced with a different billing structure than non-interval customers (GS1000NI)".*

a) Please explain why in Exhibit 3 (page 11) separate sales forecasts are developed for the GS50-1000 customers and the GS1000-1500 customers when both sets of customers are charged the same tariffs (per Exhibit 8, Tab 10).

b) Please reconcile the statement of page 18 that a different billing structure is applied to GS1000I customers as opposed to GS1000NI customers when in both the 2020 and 2021 tariff schedules set out in Exhibit 8 there appears to be no distinction made as between interval and non-interval metered customers.

RESPONSE:

a) As per OEB direction,[1] Hydro Ottawa installed Metering Inside the Settlement Timeframe ("MIST") meters for all services above 50 kW when smart metering was implemented. GS1000I can be defined as having a traditional interval meter, while the GS1000NI represents non-interval metered customers, which have smart meters. The distinction between the two different classes provides a more accurate load forecast instead of having one larger class.

   Until November 1, 2019 the GS1000NI customers were generally billed on a non-calendar month basis. The electricity charge for customers in the GS1000NI class uses the net system load shape of the distributor rather than the customer's hourly consumption. As of August 21, 2020, all distributor customers with demand greater than 50 kW shall have a MIST meter for the purpose of measuring energy delivery. The GS1000NI customers will be billed on the spot price for the electricity charge prior to the required deadline of August 21, 2020.

b) Please refer to part (a) above.

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[1] Ontario Energy Board, *Distribution System Code Amendments: Interval metering for GS>50kW customers*, EB-2013-0311 (January 16, 2014).

INTERROGATORY RESPONSE - VECC-58

3.0-VECC-58

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, pages 11-15

EB-2015-0004, Exhibit C, Attachment C1 (A), pages 16-19

SUBJECT AREA: Load Forecast

a) It is noted the Residential model used in the current Application differs from that used in EB-2015-0004. Please explain why a different model formulation was used in the current Application.

RESPONSE:

a) The current model formulation now includes a CDM per customer component. Hydro Ottawa has been promoting CDM for many years. Consequently, residential average use has been declining at a faster rate than what would have occurred from only the adoption of more efficient appliances and improvements in housing thermal integrity. The addition of the CDM variable helps explain the declining customer usage and, as a result, improves on the model fit statistics.

INTERROGATORY RESPONSE - VECC-59

3.0-VECC-59

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, pages 2; 7-9; and 11-16

SUBJECT AREA: Load Forecast

Preamble:

The Application states:

"*Residential average use is modeled as a function of heating requirements (XHeat), cooling requirements (XCool), and other use (XOther)*". (Page 11)

"*XHeatm= $HDDIdx_m$ x $IncIdx^{0.15}{}_m$ x $HeatIntensity_a$*

Where

- *$HDDIDX_m$ = an index of monthly actual and normal HDD*
- *$IncIdx_m$ = indexed per capita income (a 0.15 elasticity is applied to capture small impact on heating use)*
- *$HeatIntensity_a$= annual end-use heating intensity trend (kWh per household)*" (Pages 11-12)

"XCool is derived in a similar manner" (Page 12)

"EIA develops end-use forecasts for nine census division. The end-use intensity forecasts are based on the Mid-Atlantic Census Division which includes New York. Intensities are modified to reflect Ontario end-use saturation trends; historical and forecasted end-use saturations are

calibrated to reported saturation data from Natural Resources Canada for Ontario (NRCan)".(Page 8)

The Board's Chapter 2 Filing Requirements (section 2.3.1.1) require that Applicants provide: "*Sources of data used for both the endogenous and exogenous variables. Where a variable has been constructed, a complete explanation of the variable, data used and source of the data must be provided*".

a) With respect to the Residential Model and the XHeat variable, please provide the monthly historical and forecast values for HDDIdx and IncIdx along with the annual historical and forecast values for HeatIntensity and the resulting monthly values for XHeat.

b) Please provide the derivation of the historical monthly values (2013-2019) used for HeatIntensity, including (but not limited to) i) the energy intensity values per the EIA and ii) the modifications made to reflect Ontario end-use saturation trends. Please the supporting working models, input data and specific data sources.

c) Please provide the derivation of the forecast (2020-2025) monthly values used for HeatIntensity, including (but not limited to) i) the energy intensity values per the EIA and ii) the modification made to reflect Ontario end-use saturation trends. Please the supporting working models, input data and specific data sources.

d) With respect to the Residential Model and the XCool variable, please provide the monthly historical and forecast values for CDDIdx and IncIdx along with the annual historical and forecast values for CoolIntensity and the resulting monthly values for XCool.

e) Please provide the derivation of the historical monthly values (2013-2019) used for CoolIntensity, including (but not limited to) i) the energy intensity values per the EIA and ii) the modification made to reflect Ontario end-use saturation trends. Please the supporting working models, input data and specific data sources.

f) Please provide the derivation of the forecast (2020-2025) monthly values used for CoolIntensity, including (but not limited to) i) the energy intensity values per the EIA and ii) the modification made to reflect Ontario end-use saturation trends. Please the supporting working models, input data and specific data sources.

g) With respect to the Residential Model and the XOther variable, please provide the monthly historical and forecast values for DaysIdx, IncIdx and Monthly Multiplier along with the annual historical and forecast values for OtherIntensity and the resulting monthly values for XOther.

h) Please provide the derivation of the historical monthly values (2013-2019) used for OtherIntensity, including (but not limited to) i) the energy intensity values per the EIA and ii) the modification made to reflect Ontario end-use saturation trends. Please the supporting working models, input data and specific data sources.

i) Please provide the derivation of the forecast (2020-2025) monthly values used for OtherIntensity, including (but not limited to) i) the energy intensity values per the EIA and ii) the modification made to reflect Ontario end-use saturation trends. Please the supporting working models, input data and specific data sources.

RESPONSE:

a) Please see Attachment VECC-59(A): Residential Monthly and Forecast Values.

b) Please see Attachment VECC-59(B): Derivation of Monthly Historical & Forecasted.

c) Please see Attachment VECC-59(B): Derivation of Monthly Historical & Forecasted.

d) Please see Attachment VECC-59(A): Residential Monthly and Forecast Values.

e) Please see Attachment VECC-59(B): Derivation of Monthly Historical & Forecasted.

f) Please see Attachment VECC-59(B): Derivation of Monthly Historical & Forecasted.

g) Please see Attachment VECC-59(A): Residential Monthly and Forecast Values.

h) Please see Attachment VECC-59(B): Derivation of Monthly Historical & Forecasted.

i) Please see Attachment VECC-59(B): Derivation of Monthly Historical & Forecasted.

INTERROGATORY RESPONSE - VECC-60

3.0-VECC-60

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, pages 10 and 26-27

SUBJECT AREA: Load Forecast

Preamble:

At page 10 the Application states:

"End-use intensity projections also reflect regional conservation activity. EIA models efficiency program impacts by reducing the costs (through "rebates") of the more efficient technology options. For Ottawa, sales and average use decline even faster than that reflected in the end-use intensity projections. Differences is likely due to more CDM activity than that embedded in the estimated model and end-use intensity trends. To capture additional CDM savings, cumulative CDM savings are included as a model variable. Historical and forecasted CDM are estimated for each rate class."

At pages 26-27 the Application states:

"In the residential model the CDM coefficient is -0.696. This implies that 30% of the CDM savings is already accounted for in the end-use intensity trends and estimated coefficients on the heating, cooling, and base-use variables. For the forecast period, 70 percent of future DSM savings will flow into the model-based forecast".

a) Exhibit 4, Tab 5, Schedule 1 (page 2) describes the major change that took place in March 2019 with respect to CDM programs in Ontario. Given this change, why is it reasonable to assume that during the test period the end-use intensity trends and estimated coefficients on the heating, cooling, and base-use variables will continue to only account for 70% of the efficiency improvements that will occur?

RESPONSE:

a) While there may have been a change with respect to CDM, there is no discernible change in billed usage. The regression model's end-use variables and CDM variables capture the usage patterns before and after March 2019. There is no identifiable shift in activity after this point. Like the application of all forecast models, it is assumed that the relationship estimated with historical data is reasonable over the near-term forecast period. Near-term results are consistent with the recent historical period. The estimated model coefficients reflect the cumulative impact of adoption of efficient end-uses and CDM activity. A pullback (or escalation) of new activity would not significantly impact the near-term trend.

INTERROGATORY RESPONSE - VECC-61

3.0-VECC-61

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, pages 4, 15 and 34

SUBJECT AREA: Load Forecast

a) Please confirm that similar to the current Application, HOL's EB-2015-0004 Application forecast Residential customer count was based on a regression that related the number of customers to population projections.

b) Please provide a schedule that compares the actual monthly customer count for 2016-2019 with results of applying the EB-2015-0004 model along with actual historical population values.

c) Please provide a Residential customer count forecast for 2020-2025 using the population forecast in the current Application and the EB-2015-0004 model.

d) Page 4 explains why data prior to 2013 was not used to develop the monthly sales model. Please explain why data prior 2013 was not used to develop the customer count model.

RESPONSE:

a) Hydro Ottawa confirms the Residential customer model is driven by population projections.

b) Please see excel Attachment VECC-61(A): Residential Customer Forecast.

c) Please see excel Attachment VECC-61(A): Residential Customer Forecast.

d) To be consistent with the sales models, the same estimation period is used for estimating the customer models.

INTERROGATORY RESPONSE - VECC-62

3.0-VECC-62

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 17

(Original) Attachment 3-1-1(D): Parts 1, 2 and 3

SUBJECT AREA: Load Forecast

a) The updated excel models posted on the Board's web-site do not include an updated versions of the Load Forecast Models. Please provide revised versions of any updated models (e.g. Attachment 3-1-1(D): Part 2).

b) Please provide a working excel file that sets out the derivation of the forecast monthly Residential average use values for 2020-2025 based on the Residential model and the forecast values for the explanatory variables.

RESPONSE:

a) The updated models are provided in Attachment VECC-62(A): Updated Load Forecast Models.

b) All of the inputs, including forecast variables, estimated coefficient, and model structure necessary to replicate the forecast, are included in Attachment VECC-62(A): Updated Load Forecast Models.

INTERROGATORY RESPONSE - VECC-63

3.0-VECC-63

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 17

Attachment 3-1-1(D): Part 1 - Load Forecast Data - Customers

SUBJECT AREA: Load Forecast

a) Please provide a working excel file that sets out the derivation of the forecast monthly Residential customer count values for 2020-2025 based on the Residential model and the forecast values for the explanatory variables.

RESPONSE:

a) Please see the response to interrogatory VECC-62, including Attachment VECC-62(A): Updated Load Forecast Models.

INTERROGATORY RESPONSE - VECC-64

3.0-VECC-64

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, pages 17-18 and 22

Attachment 3-1-1(D): Part 2 - Load Forecast Data – kWh

SUBJECT AREA: Load Forecast

Preamble:

The Board's Chapter 2 Filing Requirements (section 2.3.1.1) require that Applicants provide: "*Sources of data used for both the endogenous and exogenous variables. Where a variable has been constructed, a complete explanation of the variable, data used and source of the data must be provided*".

a) For each of the four GS class models (i.e., the classes set out in Table 6) please provide the following:
   i) For the XHeat variable, the monthly historical (2013-2019) and forecast (2020-2025) values for $EconVar_m$ and HDD_m and the annual historic and forecast values for EI_{heat}.
   ii) The derivation of the historical monthly values (2013-2019) used for EI_{heat}, including (but not limited to) i) the energy intensity values per the EIA and ii) any modification made to reflect Ontario end-use trends. Please the supporting working models, input data and specific data sources.
   iii) The derivation of the forecast (2020-2025) monthly values used for EI_{heat}, including (but not limited to) i) the energy intensity values per the EIA and ii) any modifications made to reflect Ontario end-use trends. Please the supporting working models, input data and specific data sources.

iv) For the XCool variable, the monthly historical (2013-2019) and forecast (2020-2025) values for $EconVar_m$ and CDD_m and the annual historic and forecast values for $EI_{cool.}$

v) The derivation of the historical monthly values (2013-2019) used for EI_{cool}, including (but not limited to) i) the energy intensity values per the EIA and ii) any modification made to reflect Ontario end-use trends. Please the supporting working models, input data and specific data sources.

vi) The derivation of the forecast (2020-2025) monthly values used for EI_{cool}, including (but not limited to) i) the energy intensity values per the EIA and ii) any modifications made to reflect Ontario end-use trends. Please the supporting working models, input data and specific data sources.

vii) For the XOther variable, the monthly historical (2013-2019) and forecast (2020-2025) values for $EconVar_m$ and HDD_m and the annual historic and forecast values for $EI_{other.}$

viii) The derivation of the historical monthly values (2013-2019) used for EI_{other}, including (but not limited to) i) the energy intensity values per the EIA and ii) any modification made to reflect Ontario end-use trends. Please the supporting working models, input data and specific data sources.

ix) The derivation of the forecast (2020-2025) monthly values used for EI_{other}, including (but not limited to) i) the energy intensity values per the EIA and ii) any modifications made to reflect Ontario end-use trends. Please the supporting working models, input data and specific data sources.

x) Provide a working excel file that sets out the derivation of the monthly forecast sales for 2020-2025 based on the model coefficients and the forecast values for the explanatory variables. Note: In those cases where a separate adjustment is made for CDM (outside that predicted by the model), please show this adjustment separately.

RESPONSE:

a)

i) Please refer to excel Attachment VECC-64(A): Monthly Historical and Forecast Values.

ii) Please refer to excel Attachment VECC-64(B): Derivation of Monthly Historical and Forecasted.

iii) Please refer to excel Attachment VECC-64(B): Derivation of Monthly Historical and Forecasted.

iv) Please refer to excel Attachment VECC-64(A): Monthly Historical and Forecast Values.

v) Please refer to excel Attachment VECC-64(B): Derivation of Monthly Historical and Forecasted.

vi) Please refer to excel Attachment VECC-64(B): Derivation of Monthly Historical and Forecasted.

vii) Please refer to excel Attachment VECC-64(A): Monthly Historical and Forecast Values.

viii) Please refer to excel Attachment VECC-64(B): Derivation of Monthly Historical and Forecasted.

ix) Please refer to excel Attachment VECC-64(B): Derivation of Monthly Historical and Forecasted.

x) Please refer to the response provided in interrogatory VECC-62 and Attachment VECC-62(A): Updated Load Forecast Models.

INTERROGATORY RESPONSE - VECC-65

3.0-VECC-65

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, pages 2-3 and Attachment C, pages 3, 10, 19, 23 and 24

Attachment 3-1-1(D): Part 2 - Load Forecast Data – kWh

SUBJECT AREA: Load Forecast

Preamble:

At page 19 the Application states:

> *"For GS1500, GS5000, Large Users, MU and Street Lighting CDM adjustments are made by subtracting future CDM savings from the model predicted results".*

At page 23 the Application states:

> "*Large User sales have been relatively constant since 2016. We assume that sales continue at this level over the next five years*".

At page 24 the Application states:

> *"The forecast is derived by holding current street lighting sales constant and then adjusting for expected savings from further CDM street lighting activity."*

a) For the GS1500, GS5000, Large User, MU and Street Lighting classes please provide a schedule that sets out the 2020-2025 sales predictions produced by the model/analysis prior to any CDM adjustment, the CDM adjustment and the resulting proposed sales forecasts (both MWhs and kW) as set out in Updated Exhibit 3, revised Tables 1 and 2.

b) Please demonstrate that the Large User sales forecast (prior to CDM adjustments) is consistent with historic sales since 2016.

c) Please explain the basis for the expected future savings from CDM street lighting activity

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RESPONSE:

a) Please refer to excel Attachment VECC-65(A): Load Forecast - No CDM for the forecast results prior to CDM adjustments. The demand forecast (kW) does not have an implicit CDM adjustment. The demand forecast is the output of a regression model which relates class kW to class MWh. The demand forecasts in Attachment VECC-65(A) are the result of running the non-CDM adjusted MWh through the demand models.

b) Annual Large User sales have averaged 601,423 MWh from 2016-2019. The average over the last two years was 605,331 MWh. The average annual forecast value of 604,815 MWh is consistent with historical sales.

c) The Load Forecast uses a historical average percentage of kWh attributed to Street Light activity and assumes a similar percentage for future saving. The assumption is that some of the street lights are not currently part of the conversion program, and will be converted over the 2021-2025 term.

INTERROGATORY RESPONSE - VECC-66

3.0-VECC-66

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 22

Attachment 3-1-1(D): Part 1 - Load Forecast Data - Customers

SUBJECT AREA: Load Forecast

a) For the GS50 customer count model, the historical residential customer counts used (per the GS50-Data Tab of the excel model) do not appear to match the actual historic residential customer counts (per the Residential-Data Tab). Please explain why.

b) Please re-estimate the GS50 customer count model using the actual historic residential customer counts and provide the resulting GS50 customer count forecast for 2020-2025.

RESPONSE:

a) The residential customer counts in the GS50 customer model are the predicted value from the residential customer model, not the actual historical values. Itron will sometimes use the predicted value as it smooths through any billing data noise. Given the residential data series and model fit, using actual or predicted customers does not meaningfully change the results.

b) The requested information is provided in excel Attachment VECC-66(A): GS50 Re-Estimate.

INTERROGATORY RESPONSE - VECC-67

3.0-VECC-67

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 22

Attachment 3-1-1(D): Part 1 - Load Forecast Data – Customers

SUBJECT AREA:

Preamble:

At page 22 the Application states: "*A simple linear trend model is used to forecast customers for the GS1000 rate classes (non-interval and interval-meter classes) as customers have been migrating from non-interval rate class to the interval rate class*".

a) While the Application states that a simple trend model was used for the GS1000 rate class, the GS1000 model in the excel file uses the residential customer count to predict GS1000 customers. Please reconcile.

b) If a trend model is used for the GS1000 rate class, please indicate the historic years used to determine the trend, why these years were chosen and provide the supporting details.

c) If a model based on Residential customer counts is used, please confirm that the model is developed using actual historic residential customer counts.

RESPONSE:

a) Separate models are estimated to forecast customers for the GS1000 non-interval and GS1000 interval rate classes. The GS1000 non-interval customer model uses a simple trend as the number of customers are declining. The GS1000 interval customer model uses the residential customer forecast as a driver, as there is a strong correlation between customer growth and growth in residential customers.

b) The trend is determined by the period over which the model is estimated. The model is estimated from June 2015 to December 2019. This period was chosen because prior to June 2015 there was a large downward shift in customer count in the GS1000 rate class.

c) The GS1000 interval customer model is estimated based on the historical actual residential customer counts.

INTERROGATORY RESPONSE - VECC-68

3.0-VECC-68

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 26

Attachment 3-1-1(D): Part 3 - Load Forecast Data – kW

SUBJECT AREA: Load Forecast

Preamble:

At page 26 the Application states: "*Billing demand is a measure of a customer's highest hourly demand over the billing period. Monthly billing demand regression models are estimated for each rate class. Demands are modeled as a function of monthly sales and monthly binary variables*".

a) Appendix A of Attachment C does not contain any of the models used to forecast customer class billing demand. The excel file only contains the model for the GS1000I class. Please provide the model details for the other customer classes that are demand billed.

RESPONSE:

a) Please see the response to interrogatory OEB-131, including Attachment OEB-131(A): Part 3 - Load Forecast Data kW.

INTERROGATORY RESPONSE - VECC-69

3.0-VECC-69

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, pages 10 and 26-27

Updated Exhibit 3, Tab 1, Schedule 1, page 5

Attachment 3-1-1(D): Part 2 - Load Forecast Data – kWh

IESO Final 2015, 2016 and 2017 CDM Reports

IESO 2018 Participation and Cost Report

SUBJECT AREA: CDM

a) Please provide a revised version of Table 4 (page 10) with the forecast CDM broken out according to HOL's rate classes and that shows the total cumulative CDM for each year.

b) What is the base year from which the cumulative savings set out in Table 4 are calculated (i.e., in what year are the first savings assumed to occur)?

c) The 2020-2025 CDM forecast on page 10 (Table 4) is titled "Cumulative CDM savings". Please provide the historical values (up to the year 2019) for each customer class (per the response to part (a)) starting from the base year per the response to part (b).

d) Please provide a schedule/excel file for each customer class and for HOL in total that sets out the following:

Impact of Historical and Forecast CDM					
Calendar Year/ CDM Program Year	Base Year	Columns for Each Subsequent Year up to 2024			2025
Base Year CDM Impact					
Actual CDM impacts for each year to 2019 – one row per year					
Forecast 2020 CDM Impacts					
Forecast CDM impacts for each year to 2025 – one row per year					
Total (Matching Response to parts a) & c)					

If the totals do not reconcile with the responses to parts a) & c), please explain why.

e) Please explain and provide a working excel file that sets out the derivation of the monthly residential CDM values per customer used in Attachment 3-1-1(D) – Part 2 (Res-Data Tab) based on the response to parts (a) – (c).

f) Please provide (if not already on the record) the IESO reports used to determine the annual CDM savings by customer class set out in the response to part (d) for the years up to (and including) 2019.

g) Please explain how the values for each year (per part (d)) were derived from the IESO Reports for the program years up to and including 2019.

h) Please reconcile the annual cumulative savings provided in the response to part (d) with the CDM savings for GS50 as set out in Attachment 3-1-1(D) – Part 2 (GS50 - Data Tab).

i) Please reconcile the annual cumulative savings provided in the response to part (d) with the CDM savings for GS1000 as set out in Attachment 3-1-1(D) – Part 2 (GS1000 - Data Tab).

RESPONSE:

A response to this interrogatory will be provided in full during the week of June 8th, 2020.

INTERROGATORY RESPONSE - VECC-70

3.0-VECC-70

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, pages 5-6

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 10

Exhibit 4, Tab 1, Schedule 6, pages 7-9

Attachment 3-1-1(D): Part 2 - Load Forecast Data – kWh

Updated Exhibit 1, Tab 1, Schedule 1, pages 3-4

SUBJECT AREA: CDM

Preamble:

In Updated Exhibit 3 (page 5) the Application states:

> *Tables 6 and 7 below summarize Hydro Ottawa's CDM adjustments to its load forecast. The CDM adjustments are comprised of assumptions related to the following:*
>
> - *Projected CDM savings from projects that are subject to contractual agreements between the utility and customers, made on or before April 30, 2019;*
> - *Estimated rate base savings, as outlined in Exhibit 4-1-6: Conservation and Demand Management; and*
> - *Estimated impacts related to the continuation of CDM programs which are still being administered at the provincial level (i.e. by the Independent Electricity System Operator ["IESO"]).*

a) Please confirm that Exhibit 4, Tab 1, Schedule 6 is still part of HOL's overall Application.

b) For each customer class please provide a breakdown of the annual 2021-2025 CDM adjustments set out in Table 6 into the three categories referenced above from page 5.

c) Are the "rate base savings" (per the second bullet in the Preamble) attributable to OPA contracted/administered programs? If yes, please explain how these savings differ from those noted in the first and third bullets.

d) If the "rate base savings" are not attributable to OPA contracted/administered programs, is HOL seeking Board approval of the related utility programs per Board Report EB-2012-0003, Guidelines for Electricity Distributor Conservation and Demand Management?
   i) If not, why not?
   ii) If yes, please indicate where in the Application HOL has addressed the approval requirements set out in the Board's Report.

e) Please reconcile – for each customer class - the Energy Sales CDM Adjustments by Customer Class set out in Updated Exhibit 3, Tab 1, Schedule 1 – Table 6 with those set out in Attachment C, page 10 – Table 4.

f) Please reconcile the Residential CDM values for 2021-2025 as set out in Table 6 (Updated Exhibit 3, Tab 1, Schedule 1) with the 2021-2025 Residential CDM values used in the Res-Data Tab of Attachment 3-1-1(D): Part 2 - Load Forecast Data – kWh.

g) Please reconcile the GS50 CDM values for 2021-2025 as set out in Table 6 (Updated Exhibit 3, Tab 1, Schedule 1) with the 2021-2025 GS50 CDM values used in the GS50-Data Tab of Attachment 3-1-1(D): Part 2 - Load Forecast Data – kWh.

h) Please reconcile the GS1000 (Interval and Non-Interval) CDM values for 2021-2025 as set out in Table 6 (Updated Exhibit 3, Tab 1, Schedule 1) with the 2021-2025 GS1000 CDM values used in the GS1000-Data Tab of Attachment 3-1-1(D): Part 2 - Load Forecast Data – kWh.

RESPONSE:

a) Hydro Ottawa confirms that Exhibit 4-1-6: Conservation and Demand Management remains part of the utility's Application. Please see the response to interrogatory OEB-134 for more detailed information regarding Exhibit 4-1-6.

b) Please see part (a) of the response to interrogatory OEB-134.

c) No, the savings associated with "rate base" CDM activities are in addition to the savings attributed to IESO contracted/administrative program savings (i.e. in addition to the first and third bullets on page 6 of UPDATED Exhibit 3-1-1: Load Forecast). Please see the response to part (c) of interrogatory OEB-134 for more detailed information.

d) Please refer to the response to interrogatory CCC-32.

e) The CDM adjustments shown in Table 6 of UPDATED Exhibit 3-1-1: Load Forecast are the results of comparing a With-CDM forecast and a forecast with future cumulative CDM savings added back (i.e. No CDM forecast). The table on page 10 of UPDATED Attachment 3-1-1(C): Hydro Ottawa Long-Term Electric Energy and Demand Forecast shows the annualized CDM savings targets. Itron's estimate of historical and forecasted CDM savings are derived from reported annualized savings. Annualized savings represent what savings would be if all measures for that year were installed in the beginning of the year. It is not the actual sum of the monthly CDM savings. The annualized savings are used in constructing a monthly CDM model variable designed to capture CDM sales impact. The estimated model coefficient on CDM (generally less than 1.0) represents the additional impact of CDM on energy not captured by the other model variables. As a result of this specification, Itron avoided "double counting" CDM savings. The No CDM forecast is generated by adding future cumulative projected CDM savings to the With-CDM forecast.

f) The cumulative incremental new CDM values in the Res-Data Tab of Attachment 3-1-1(D): Load Forecast Data, Part 2, multiplied by the number of residential customers, match the numbers seen in Table 6 to within 1-2 MWh.

g) The cumulative incremental new CDM values in the GS50-Data Tab of Attachment 3-1-1(D): Load Forecast Data, Part 2, matches the numbers seen in Table 6 to within 1-2 MWh.

h) The cumulative incremental new CDM values in the GS1000-Data Tab of Attachment 3-1-1(D): Load Forecast Data, Part 2, matches the numbers seen in Table 6 to within 1-2 MWh.

INTERROGATORY RESPONSE - VECC-71

3.0-VECC-71

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 1, Schedule 1, Attachment C, page 27

SUBJECT AREA: CDM

The Application states:

"Sales impact from future CDM savings are derived by executing savings projections through the estimated model where CDM is included as a model variable and treated as in the past (subtracted from the forecast model estimate) for GS1500, GS5000, Street Lighting, and MU".

a) Please provide a schedule that sets out the 2019-2025 values for the two curves portrayed in Figure 21.

b) Please provide a schedule that provides the 2019-2025 values for each customer class:
   i) Based on No CDM Adjustment and ii) With CDM Adjustment consistent with part (a).

RESPONSE:

a) Table A below provides a schedule that sets out the 2019-2025 values from the two curves portrayed in Figure 21 of Attachment 3-1-1(C): Hydro Ottawa Long-Term Electric Energy and Demand Forecast.

Table A – CDM Forecast Comparison (MWh)

Curve	2019	2020	2021	2022	2023	2024	2025
No CDM Adjustment	7,240,873	7,215,786	7,230,945	7,276,481	7,326,000	7,395,485	7,428,831
With CDM Adjustment	7,240,876	7,133,965	7,068,427	7,090,631	7,118,827	7,166,993	7,181,368

b) Table B provides the 2019-2025 customer class levels schedule based on No CDM Adjustment. Sentinel Lights are not included in Tables A, B, and C, as Hydro Ottawa provided the forecast for that customer class.

Table B – No CDM Adjustment by Rate Class (MWh)

Curve	2019	2020	2021	2022	2023	2024	2025
Residential	2,263,476	2,257,979	2,261,415	2,282,954	2,308,584	2,342,498	2,362,532
Small Commercial	724,442	714,659	716,020	718,931	721,818	726,341	727,769
Commercial	3,604,672	3,591,179	3,603,126	3,624,661	3,646,112	3,675,953	3,689,949
Large User	602,082	605,919	604,263	604,263	604,263	605,919	604,263
Street Light	26,728	26,894	27,415	27,419	27,419	27,419	27,419
Unmetered Scattered Load	14,550	14,164	13,714	13,261	12,812	12,363	11,907
Dry Core	4,923	4,993	4,993	4,993	4,993	4,993	4,993
Total	7,240,873	7,215,787	7,230,946	7,276,482	7,326,001	7,395,486	7,428,832

Table C below provides the 2019-2025 customer class levels schedule based on With CDM Adjustment, consistent with part (a) above.

1 **Table C – Adjusted for Future CDM by Rate Class (MWh)**

Curve	2019	2020	2021	2022	2023	2024	2025
Residential	2,263,478	2,254,425	2,252,938	2,273,819	2,299,366	2,333,197	2,353,150
Small Commercial	724,441	707,565	699,870	699,135	697,637	697,775	695,838
Commercial	3,604,670	3,539,987	3,500,626	3,505,440	3,511,721	3,526,398	3,526,415
Large User	602,083	588,827	574,291	572,889	572,034	572,834	570,390
Street Light	26,731	24,063	22,108	21,224	20,413	19,602	18,855
Unmetered Scattered Load	14,550	14,105	13,601	13,131	12,663	12,194	11,727
Dry Core	4,923	4,993	4,993	4,993	4,993	4,993	4,993
Total	7,240,876	7,133,965	7,068,427	7,090,631	7,118,827	7,166,993	7,181,368

2

INTERROGATORY RESPONSE - VECC-72

3.0-VECC-72

EXHIBIT REFERENCE:

Exhibit 3, Tab 1, Schedule 1, Attachment B

Updated Exhibit 1, Tab 1, Schedule 1, page 3

SUBJECT AREA: Deferral and Variance Accounts

a) Please confirm that Exhibit 3, Tab 1, Schedule 1, Attachment B is unchanged from the original Application.

b) Is HOL proposing LRAMVA thresholds for the test years 2021-2025?
   i) If yes, what are they for each customer class and how were they calculated?
   ii) How do the proposed threshold values relate to the LRAMVA threshold set out at page 3 of Attachment B?

c) Is the Manual Adjustment for 2020 (Attachment B, per page 3) used at all in the development of the 2021-2025 proposed load forecast?
   i) If yes, please explain how.

RESPONSE:

a) Hydro Ottawa confirms that Attachment 3-1-1(B): OEB Appendix 2-I - Load Forecast CDM Adjustment Workform is unchanged. Hydro Ottawa notes that the amount entered into Appendix 2-I is the utility's 2015-2020 CDM Target and does not represent the threshold related to part (b) of this response.

b) i) Hydro Ottawa confirms that it is proposing LRAM thresholds for the Test Years 2021-2025. The thresholds are set out in Tables 6 and 7 of UPDATED Exhibit 3-1-1: Load Forecast.

ii) As indicated in part (a) above, the thresholds are not equal to the values on page 3 of Attachment 3-1-1(B): OEB Appendix 2-I - Load Forecast CDM Adjustment Workform. In reading the instruction for OEB Appendix 2-I, Hydro Ottawa's interpretation is that the utility should only include CDM savings related to the former Conservation First Framework ("CFF") program in this Appendix.

c) Persistent savings related to the former CFF program are part of the assumptions in the Load Forecast. Please see the response to interrogatory OEB-138 for details on future CDM savings within the Load Forecast.

INTERROGATORY RESPONSE - VECC-73

3.0-VECC-73

EXHIBIT REFERENCE:

Updated Exhibit 3, Tab 2, Schedule 1, pages 1 & 6 and Attachment A

SUBJECT AREA: Other Revenue

a) With respect to Attachment A, please explain why the 2021 forecast value for Loss from Retirement of Utility and Other Property (USOA#4362) is negative whereas as the values for the preceding years are all positive.

b) With respect to Table 1 (page 1), please break down the 2022 to 2025 forecast by USOA.

c) With respect to Table 1 (page 1), please explain why the value for Other Income & Deductions decreases materially between 2021 and 2022.

RESPONSE:

a) The years 2016-2018 had actual net losses from the retirement of assets (positive values) while the 2019 year had actual net gain from the retirement of assets (negative values). Table A below shows the actual net losses/gain balance prior to any adjustment to or from USoA 4362 to USoA 1508.

Table A – USoA 4362 Loss from Retirement of Utility and Other Property (2016-2021)

	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Bridge	2021 Test
Actual net (loss)/gain	$(407,962)[1]	$(152,312)	$(263,770)	$167,471[2]	$(301,440)	$(388,726)
Adjustment to 1508	$548,079	$350,661	$462,119	$30,878	$499,789	$0
NET BALANCE[3]	**$140,117**	**$198,349**	**$198,349**	**$198,349**	**$198,349**	**$(388,726)**

Hydro Ottawa received approval for a Sub-Account 1508 - Other Regulatory Assets - Gains and Losses on disposal of Fixed Assets Variance Account, as part of the Approved Settlement Agreement governing the utility's 2016-2020 rate term.[4] Please refer to UPDATED Exhibit 9-1-3: Group 2 Accounts for further details. The amount reported in USoA 4362[5] has been adjusted by the difference between the forecast gain and the actual loss on the disposal of fixed assets. USoA 4362 thus shows a net gain from the retirement of assets (negative values). Please see Table 6 in UPDATED Exhibit 9-1-3: Group 2 Accounts for more details.

The 2021 forecast value is a net loss comparable with actual net losses for years 2016-2019 (excluding the net gain on the sale of old facilities).

b) Table B below provides a breakdown of Other Revenue by USofA, which corresponds to the updated version of Table 1 in UPDATED Exhibit 3-2-1: Other Revenue.

[1] This includes additional losses that were not recorded to USoA1508 Gain and Loss on disposal of fixed assets Variance Account. Only the difference between net loss of $349,731 and USofA 4362 OEB-Approved amount of $198,349 was recorded to USoA1508 Gain and Loss on disposal of fixed assets Variance Account.
[2] 2019 includes net gain of $2,151,860 on the disposal of Existing Facilities (2019 without Existing Facilities is net loss of $1,984,390).
[3] This has been adjusted by the difference between the forecast and actual loss on the disposal of fixed assets.
[4] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Approved Settlement Proposal*, EB-2015-0004 (December 7, 2015).
[5] This has been adjusted by the difference between the forecast and actual loss on the disposal of fixed assets.

Table B – Other Operating Revenue - 2022-2025

Other Operating Revenue		Test Year 2022	Test Year 2023	Test Year 2024	Test Year 2025
USofA #	**USofA Description**				
4325	Specific Service Charges	$5,394,162	$5,678,587	$5,910,078	$6,212,623
4225	Late Payment Charges	$1,000,000	$1,000,000	$1,000,000	$1,000,000
4082	Retail Services Revenues	$143,811	$128,608	$115,133	$103,188
4084	Service Transaction Requests	$4,068	$3,987	$3,907	$3,829
4086	SSS Admin Charge	$2,444,127	$2,542,545	$2,641,682	$2,741,945
4090	Electric Services Incidental to Energy Sales	$293,196	$296,340	$299,484	$314,028
4315	Revenue from Leased Plant	$1,975,128	$1,975,128	$1,975,128	$1,975,128
4325	Revenue from Merch, Jobbing	$9,690,667	$9,656,279	$9,756,732	$9,932,250
4330	Expenses from Merch, Jobbing	$(9,223,193)	$(9,291,587)	$(9,214,962)	$(9,381,438)
4355	Gain on Disposal of Property	$0	$0	$0	$0
4360	Loss on Disposal of Property	$0	$0	$0	$0
4362	Loss from Retirement of Utility and Other Property	$(751,182)	$(322,643)	$(335,790)	$(444,844)
4405	Interest and Dividend Income	$0	$0	$0	$0
Specific Service Charges[6]		**$5,394,162**	**$5,678,587**	**$5,910,078**	**$6,212,623**
Late Payment Charges[7]		**$1,000,000**	**$1,000,000**	**$1,000,000**	**$1,000,000**
Other Operating Revenue[8]		**$2,885,203**	**$2,971,480**	**$3,060,205**	**$3,162,990**
Other Income or Deductions[9]		**$1,691,420**	**$2,017,176**	**$2,181,108**	**$2,081,096**
TOTAL OTHER OPERATING REVENUE		**$10,970,785**	**$11,667,243**	**$12,151,392**	**$12,456,709**

c) In the updated version of Table 1 in UPDATED Exhibit 3-2-1: Other Revenue, the Other Income and Deductions line decreases by $0.4M, which is largely attributable to an increase in asset disposal as a result of the AMI Analytics and Integration Enablement. Please refer to section 3.6.2 of Attachment 2-4-3(E): Material Investments for further details.

[6] 4325
[7] 4225
[8] 4082, 4084, 4086, 4090
[9] 4315, 4325, 4330, 4355, 4360, 4362, 4405

INTERROGATORY RESPONSE - VECC-74

4.0 -VECC -74

EXHIBIT REFERENCE:

Exhibit 4

SUBJECT AREA: Productivity

a) What metrics or performance measures does HOL have to help it understand the productivity of its operation and maintenance programs?

b) Please provide the summary results of any management tools used by HOL to help it do more maintenance with less money.

RESPONSE:

a) Hydro Ottawa employs several sets of metrics and performance measures to assist the utility in measuring and understanding the productivity of its operation and maintenance programs. These include the following:

- Key performance indicators ("KPIs") for monitoring and continually improving the utility's Asset Management and Asset Management System;[1]
- KPIs related to safety, system reliability, and cost control, which are reported annually to the OEB and parties to the Approved Settlement Agreement governing Hydro Ottawa's 2016-2020 rate plan;[2]
- Labour utilization, OM&A, asset efficiency, and profitability metrics in the utility's Corporate Productivity Scorecard (see Attachment 1-1-13(A));
- Numerous metrics utilized to measure the utility's performance in its four strategic areas of focus (Customer Value, Financial Strength, Organizational

[1] For additional information on these KPIs and the formal procedure adopted by Hydro Ottawa to govern their use, please see the response to interrogatory SEC-32.
[2] These reports are available on Hydro Ottawa's website: https://hydroottawa.com/about-us/regulatory-affairs/custom-incentive-reports.

Effectiveness, and Corporate Citizenship), as part of its Corporate Performance Scorecard (see Attachment SEC-4(A): 2016-2020 Corporate Performance Scorecards);

- OEB Service Quality Requirements (see Exhibit 2-4-6: Service Quality and Reliability Performance);
- Metrics in the annual Electricity Utility Scorecard published by the OEB (see Attachment 1-1-12:(C)); and
- Metrics in the OEB's annual Yearbook of Electricity Distributors (see Attachment 1-1-12(D): Ontario Energy Board Electricity Distributor Yearbook and Performance Dashboard).

b) Hydro Ottawa uses a number of management systems and tools to help enable the utility to execute its maintenance activities and programs more cost-effectively and efficiently. These include, but are not limited to, the following:

- Strategic Asset Management Plan ("SAMP"): Hydro Ottawa is aligning asset management processes and practices with the ISO 55001 standard. This ensures that strategic asset decision-making processes achieve a balanced weighting of cost, risk, and asset performance that meet or exceed service level expectations of customers; comply with the terms of applicable acts, licences, and codes; improve asset value and resource efficiency; and minimize health, safety, and environmental impacts. A copy of the SAMP is included in this Application as Attachment 2-4-3(G). The Asset Management Plans for the utility's 13 classes of assets include specific sections addressing operations and maintenance plans. In addition, a report on Hydro Ottawa's progress towards achieving certification with the ISO 55001 standard can be viewed at Attachment 2-4-3(J): ISO 55000 Gap Analysis.
- Mobile Workforce Management ("MWM"): MWM is an automated scheduling and dispatch tool designed to optimize the scheduling and routing of work and crews to increase productivity across all types of work and enhance customer service.

- Mobile Inspector: This is a software tool that stores all maintenance and inspection data in one database for easy access. It is linked with the utility's geographic information system ("GIS") so that maps with locations of the assets are readily available for staff and contractors completing programs.
- Bluebeam: This is a document and project management solution which allows users to transform scanned images into easily searchable documents. It provides a set of markup tools to add text, notes, stamps, and highlights to documents. Photos and videos can also be embedded within markups. This permits easy collaboration between plant inspection resources without having to share physical project folders.
- Electronic Drills: These drills have replaced manual carbon paper pole drills. They are faster and permit storage of test results, as opposed to having to record results manually.

This Application includes several pieces of evidence illustrating examples of the maintenance savings achieved from using these management systems and tools:

- Attachments 1-1-10(A) through (C) – annual summaries for 2016, 2017, and 2018 of Hydro Ottawa initiatives aligned with Renewed Regulatory Framework outcomes; and
- Exhibit 1-1-13: Productivity and Continuous Improvement Initiatives.

Finally, Hydro Ottawa has an Internal Audit function that provides independent assurance that the utility's risk management, governance, and internal control processes are operating effectively. Please see the response to interrogatory SEC-31 for evidence that Hydro Ottawa has implemented recommendations from a 2016 Follow Up Internal Audit of Distribution Systems & Asset Maintenance. Implementation was completed in Q1 2017.

INTERROGATORY RESPONSE - VECC-75

4.0 -VECC -75

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 3/ Appendix 2-M Updated – Regulatory Costs

SUBJECT AREA: OM&A

a) Please provide a breakdown by consultant of the $1,736,900 in consulting costs incurred for this application

b) Please breakdown the $2,211,990 in one-time application costs into: Legal, consulting, intervenor, other (please specify).

RESPONSE:

a) For a breakdown of the $1.7M consulting costs incurred for this Application, please refer to Table A below. Note that these consulting costs are one-time costs and are estimates for this Application.

Table A – Consultant Costs Incurred in Preparation of Application

Consultant Costs	2021 Test Year
Black & Veatch	$164,000
Clearspring Energy Advisors	$232,600
EA Technology	$64,000
Elenchus Research Associates	$140,000
Gartner Consulting	$127,500
Innovative Research Group	$177,000
Itron	$164,000
Mercer	$175,000
METSCO	$43,000
Navigant	$170,000
Stantec	$106,000
UMS Group	$173,890
TOTAL	**$1,736,990**

b) Hydro Ottawa is interpreting the reference to $2,211,990 to be $2,311,990, as per cell L77 in UPDATED Attachment 4-2-4(A): OEB Appendix 2-M - Regulatory Cost Schedule. The one-time application costs are broken down into legal, consulting, and intervenor costs in cells L47, L48, and L51 respectively in Appendix 2-M. The OEB Section 30 costs that are application-related, in the amount of $275K, are in cell L52.

INTERROGATORY RESPONSE - VECC-76

4.0 -VECC -76

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 3, Attachment D, Updated

SUBJECT AREA: OM&A

a) Please amend Appendix 2-D to show 2016 results.

RESPONSE:

a) Please see excel Attachment VECC-76(A): Appendix 2-D Overhead Expense Including 2016 for an amended version of Attachment 4-1-3(D): OEB Appendix 2D - Overhead Expense.

INTERROGATORY RESPONSE - VECC-77

4.0 -VECC -77

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 4, page 51 /Tab 2, Schedule 4 Updated

SUBJECT AREA: OM&A

a) What was HOL's 2019 OEB assessment cost (net of any section 30 assessments).

RESPONSE:

a) Hydro Ottawa's 2019 OEB assessment costs were $1,399,785. This includes the amount recorded into 1508 OEB Cost Assessment Variance. Please refer to the response to interrogatory OEB-181 and cell I15 of Attachment OEB-181(A): Revised UPDATED Appendix 2-M.

Hydro Ottawa confirms that the aforementioned amount is net of any section 30 assessments of $46,713, which are in cell I16 of Attachment OEB-181(A).

INTERROGATORY RESPONSE - VECC-78

4.0 -VECC -78

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 4, Table 10 & pages 28-

SUBJECT AREA: OM&A

a) What accounts for the significant decrease in collections and account costs from 2018 to 2019 (over 35% as compared to 2017) and then a significant increase from that trend in 2021 (over 50% increase as compared to 2019).

RESPONSE:

a) For details on the decrease in 2018-2019 and subsequent increase in 2021 in collections and account costs, please see section 3.1 of UPDATED Exhibit 4-1-4: Operations, Maintenance and Administration Cost Drivers and Program Variance Analysis. In addition, please refer to the response to interrogatory OEB-143.

INTERROGATORY RESPONSE - VECC-79

4.0 -VECC -79

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 4, Table 10

SUBJECT AREA: OM&A

a) What accounts for roughly 7% decrease in Customer and Community Relations spending in 2019 as compared to the prior 3 years?

RESPONSE:

a) The reduction can be largely explained by the following two reasons:

- Contact centre service costs were reduced substantially from the prior three years as a result of a transition to a new service provider with improved pricing and a decrease in average call durations. The reduction in call minutes is attributable to increased automation. Please refer to section 3.3 of UPDATED Exhibit 4-1-4: Operations, Maintenance and Administration Cost Drivers and Program Variance Analysis, as well as section 2.1.3 of Exhibit 1-1-13: Productivity and Continuous Improvement Initiatives, for additional details on the automations implemented.

- Changes in the cost recovery from Shared Services provided to affiliates through Service Level Agreements ("SLAs"). Please see section 2.8 of UPDATED Exhibit 4-1-4: Operations, Maintenance and Administration Cost Drivers and Program Variance Analysis for details. Consistent with section 2.4.3.2 of the OEB's Filing Requirements as well as OEB guidance issued in 2018, SLA costs were no longer included in OM&A as of 2019. The SLA costs, along with the associated SLA revenue, are now reported in USofA 4330 Costs from Merchandising and

Jobbing, and are deducted from Hydro Ottawa's OM&A. The shared services in the Customer and Community Relations category is related to Communication Services.

INTERROGATORY RESPONSE - VECC-80

4.0 -VECC -80

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 4,Table 10 & pages 48-

SUBJECT AREA: OM&A

a) "Engineering & Design" costs are forecast to escalate in 2020 as compared to 2019 amounts by over 25%. HOL explains this increase as the increased cost of technical support for SCADA, higher IT licence and maintenance contracts and general compensation increases. Please provide the amount of the increase from 2019 by each of those categories (or any additional categories as might be required).

b) Please clarify if the IT costs are accounted for in this line item or under the category of Information Management & Technology.

RESPONSE:

a) In 2019, Engineering & Design costs dropped to the lowest in the last five years, which can be largely explained by the fluctuation of labour recovery. The cumulative annual growth rate for Engineering & Design between 2016 and 2021 was 4.5%. The 25% increase from 2019 to 2020 represents the lowest spending year versus the highest spending year. Costs in 2021 are expected to decrease from 2020.

Please refer to Table A below for the key categories included in Engineering & Design. Labour Recovery is the recovery of the compensation costs allocated to Capital, Maintenance, and Work For Others (Distribution Recoverable Work) activities. The recovery in 2019 was larger than the 2020 budget assumption due to increased recovery, mainly in the Work For Others activity. The Work For Others activities are driven by third-party customer demand. In 2019, total Work For Others recovery was higher than 2017 and 2018. However, the assumption for 2020 is that this work would be in line with previous years and not follow the spike in 2019.

Table A – Engineering & Design OM&A Program Costs ($'000s)

Programs	2019 Historical Year	2020 Bridge Year	2020-2019 Variance	
Engineering & Design				
Labour Compensation and Benefits including the technical staff to support SCADA and GIS	$10,562	$11,045	$484	*5%*
IT Licenses and Maintenance Contracts	$974	$1,159	$185	*19%*
Other Costs include pole attachment costs, training, consulting and industry/sector membership fees	$1,627	$1,961	$334	*21%*
Labour Recovery	$(6,303)	$(5,420)	$883	*(14%)*
TOTAL	**$6,860**	**$8,746**	**$1,886**	***27%***

b) The IT costs for Engineering & Design, which include costs related to operations technology such as Geographic Information System ("GIS"), Supervisory Control and Data Acquisition ("SCADA"), and the asset management software Copperleaf C55, are captured in the Information Technology line disclosed in the table above. These costs are excluded from the Information Management & Technology category disclosed in Table 10 of UPDATED Exhibit 4-1-4: Operations, Maintenance and Administration Cost Drivers and Program Variance Analysis.

INTERROGATORY RESPONSE - VECC-81

4.0 -VECC -81

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 4, Table 10 & pages 48

SUBJECT AREA: Facilities Renewal Program

a) Please provide the assessed property taxes and the property taxes paid by HOL in 2019 for each of the properties:
   - Bank Street
   - Albion Road (A&C)
   - Merivale Road
   - Hunt Club Road
   - Dibblee Road

b) Please clarify if there is an Albion "B" property and if so whether that property has been retained by HOL.

RESPONSE:

a) Table A identifies the assessed property taxes and property taxes paid by Hydro Ottawa for each of the specified properties in 2019.

Table A – Hydro Ottawa Property Taxes 2019

Location	2019 Assessment	2019 Paid
Bank Street	$ 5,042,750	$134,177
Albion Road (A&C)	$8,418,200	$258,612
Merivale Road	$3,842,000	$117,463
Hunt Club Road	$20,702,339	$478,917
Dibblee Road	$ 6,296,080	$131,352

b) Yes, there is an Albion "B" property. This property is being retained, as there is a transformer station on that site.

INTERROGATORY RESPONSE - VECC-82

4.0 -VECC - 82

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 4, page 52

SUBJECT AREA: OM&A

a) Please confirm or clarify that the $1.0 million in flame resistant clothing is :
   i) not an incremental costs in 2021;
   ii) an annual cost.

b) Please identify in what program categories (using Table 10) these costs were formerly captured.

RESPONSE:

a) The $1.0M for flame resistant clothing represents the four-year total expense from 2018-2021, and is not an incremental cost in 2021.

b) Prior to 2018, this cost was captured in Supply Chain.

INTERROGATORY RESPONSE - VECC-83

4.0 -VECC -83

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 5, page 3

SUBJECT AREA: Compensation

a) Please provide a chart which shows the correlation and relationship between the proposed Utility Regulatory Scorecard and the corporate and divisional priorities used for senior management incentive pay.

RESPONSE:

a) In Table A below, the presentation of the Custom Performance Scorecard in Exhibit 1-1-11: Proposed Annual Reporting – 2021-2025 has been modified so as to enable a concise response to this interrogatory. The modifications consist of the addition of a column that identifies which of the utility's corporate performance goals correspond to specific subsets of the performance measures proposed for inclusion in Hydro Ottawa's Custom Performance Scorecard.[1]

For additional information on Hydro Ottawa's corporate performance goals, please refer to copies of the utility's annual corporate performance scorecards for the 2016-2020 period which have been included as attachments in the response to interrogatory SEC-4. Note that the priorities which support the corporate performance goals represent a consolidation of the divisional-level priorities used for senior management incentive pay. Additional information on these priorities is likewise available in the aforementioned attachments.

[1] To confirm, these modifications should not be interpreted as replacing Table 1 in Exhibit 1-1-11 of Hydro Ottawa's original Application.

Table A – Relationship between Custom Performance Scorecard Measures (2021-2025) and Corporate Performance Goals

RRF Outcome	OEB Reporting Category	Hydro Ottawa Custom Measures	New/ Existing	Target	Hydro Ottawa Corporate Performance Goals
Customer Focus	Customer Satisfaction	Contact Centre Satisfaction – Transactional Feedback	New	Maintain	• Assist customers in managing their energy consumption and electricity costs • Deliver on customer expectations for service quality and responsiveness
		Number of MyAccount Customers	New	Increase	
		Number of Online Billing Accounts	New	Increase	
Operational Effectiveness	Safety	All Injury/Illness Frequency Rate	New	Reduce	• Continue to enhance operational performance and productivity • Maintain leading health and safety record • Enhance organizational and employee capability
		Lost Workday Severity Rate	New	Reduce	
	System Reliability	Customer Average Interruption Duration Index	Existing	Monitor	• Maintain overall distribution system reliability • Continue to enhance operational performance and productivity
		Feeders Experiencing Multiple Sustained Interruptions	Existing	Maintain	
		Worst Feeder Analysis – Number of Feeders with Very Poor Performance	Existing	Reduce	
		Stations Exceeding Planning Capacity	Existing	≤5%	
		Feeders Exceeding Planning Capacity	Existing	≤10%	
		Stations Approaching Rated Capacity	Existing	0%	
		Feeders Approaching Rated Capacity	Existing	0%	
	Cost Control	Productive Time	Existing	Maintain	• Continue to enhance operational performance and productivity • Enhance organizational and employee capability
		Labour Allocation	Modified	Maintain	
		3-Year Average Cost per Pole – Wood Pole Replacement	New	Monitor	• Maintain overall distribution system reliability • Continue to enhance operational performance and productivity • Enhance organizational and employee capability
		3-Year Average Cost per Meter – Underground Cable	New	Monitor	
		Average Cost per Kilometer – Vegetation Management	New	Monitor	
		Average Cost per Pole – Pole Test and Inspection	New	Monitor	
	Asset Efficiency	Technology Infrastructure Cost per Employee	New	Monitor	
Public Policy Responsiveness	Environment	Annual Oil Spills & Costs of Remediation	Existing	Reduce	• Continue to enhance operational performance and productivity • Continue to improve our environmental performance and reduce our impact on the environment
		Non-Hazardous Waste Diversion Rate	New	Maintain	
		Percentage of Green Suppliers	New	Maintain	
Financial Performance	Financial Metrics	OM&A per Customer	New	Monitor	• Continue to enhance operational performance and productivity • Enhance / protect revenues from existing business lines
		Bad Debt as a Percentage of Total Electricity Revenue	New	Monitor	
		Cumulative Capital Additions per Investment Category	New	Monitor	
		Annual Capital Spending per Investment Category	New	Monitor	

INTERROGATORY RESPONSE - VECC-84

4.0 -VECC -84

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 5, pages 8-

SUBJECT AREA: Compensation

a) Using Table 3 please show separately the total annual premium cost for the post-retirement life insurance.

RESPONSE:

Hydro Ottawa is interpreting this question as referring to Attachment 4-1-5(A): Employee Compensation Strategy.

a) Table A shows separately the total annual premium cost for post-retirement life insurance.

Table A – UPDATED FOR 2019 ACTUALS – Pension and OPEB Amounts ($'000s)

Pension and OPEB	Historical				Bridge	Test
	2016	2017	2018	2019	2020	2021
Pension cost	$5,389	$5,530	$5,741	$5,720	$6,168	$6,355
Future employee benefits cost	$2,240	$832	$736	$1,232	$800	$816
Cash paid	$593	$634	$649	$717	n/a	n/a
Annual premium cost (post-retirement life insurance)	$380	$362	$415	$470	n/a	n/a

INTERROGATORY RESPONSE - VECC-85

4.0 -VECC -85

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 5, pages 8-

SUBJECT AREA: Compensation

Statistics Canada publishes "Employee wages by industry – annual" which includes a number of categories including "**Total employees, all industries" and "Utilities"** in current dollars. (www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1410006401)

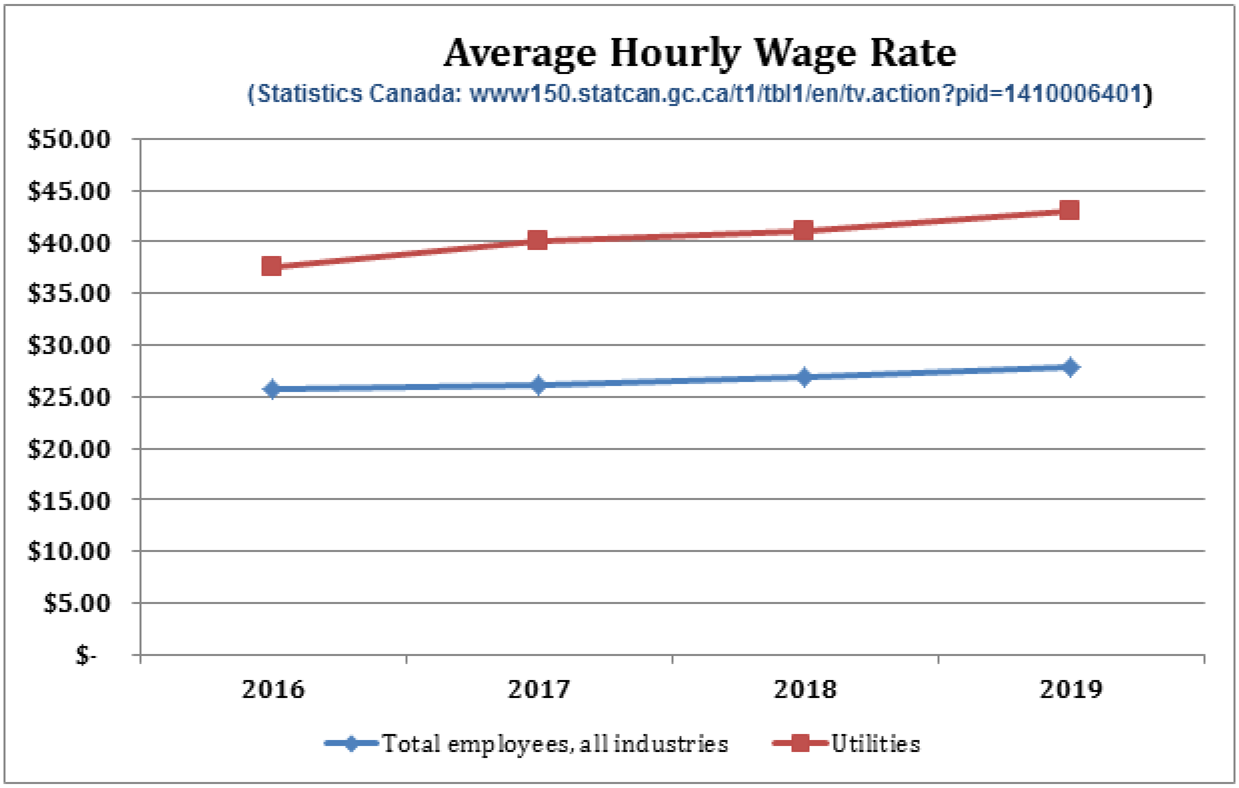
a) For the period 2012 to 2019 please provide a graph which shows the wage trend growth for those two categories (as per Statistics Canada).

b) Using Appendix 2-K please provide separately a graph which shows the average total compensation for each of management and non-management (i.e. Total $/FTE) for the period 2012 to 2019. Please provide a table to accompany this chart which includes the calculated data.

RESPONSE:

a) Figure A below represents the actual average hourly wage for both "**Total employees, all industries" and "Utilities",** as sourced from Statistics Canada. Please note that the period covered is from 2016-2019, the timeframe for which data is supplied for this Application.

Figure A – 2016-2019 Average Hourly Wage Rate - "Total Employees, All Industries" and "Utilities"

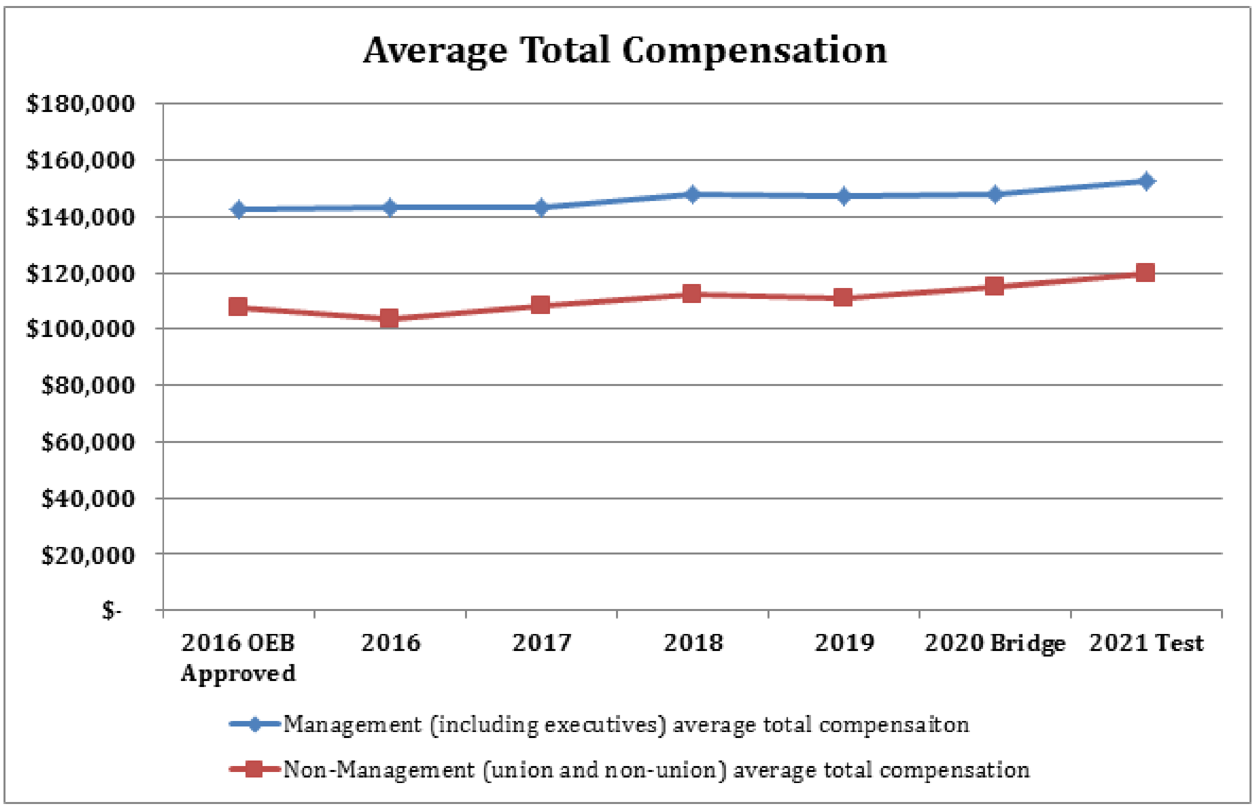


b) Table A and Figure B below present the average total compensation for both the management and non-management groups, encompassing 2016 OEB-approved levels, 2016-2019 actuals, and forecasts for 2020 and 2021. Consistent with part (a) above, this is the timeframe for which data is supplied for this Application.

Table A – Average Total Compensation - Management and Non-Management

	2016 OEB-Approved	Historical				Bridge	Test
		2016	2017	2018	2019	2020	2021
Management (including executives)	$142,563	$143,036	$143,486	$147,629	$147,329	$147,956	$152,773
Non-Management (union and non-union)	$107,877	$103,800	$107,995	$112,369	$111,017	$114,778	$119,405

Figure B – Average Total Compensation - Management and Non-Management



INTERROGATORY RESPONSE - VECC-86

4.0 -VECC -86

EXHIBIT REFERENCE:

Exhibit 4, Tab 1, Schedule 5, page 3

SUBJECT AREA: Compensation

a) Please amend Appendix 2-K to show the amount of compensation capitalized and expensed in each year 2016-2021.

RESPONSE:

a) Please see Attachment VECC-86(A): Updated Appendix 2-K - Employee Costs - Capitalized and Expensed provided in excel format, which includes capitalized and expensed labour identified for the period 2016-2021.

INTERROGATORY RESPONSE - VECC-87

4.0 -VECC -87

EXHIBIT REFERENCE:

Exhibit 4, Tab 3, Schedule 1, Table 3 Updated

SUBJECT AREA: Depreciation

a) What accounts for the unusually large amount of disposals in 2019 - specifically the disposals in General Plant, Equipment and IT Assets.

RESPONSE:

a) The larger amount of disposals in 2019 in General Plant is due to disposal of Hydro Ottawa's old facilities at Albion Road and Merivale Road. The amount in Equipment and IT Assets is due to disposal of assets that have been fully depreciated and no longer in use.

INTERROGATORY RESPONSE - VECC-88

4.0 -VECC -88

EXHIBIT REFERENCE:

Exhibit 4, Tab 2, Schedule 1

SUBJECT AREA: Shared Services & Corporate Cost Allocation

a) What HR services are provided by HOHI to HOL?

b) How many employees are in HOL HR? How many are in HOHI HR?

c) Please explain what communication services are provided to HOL by HOHI. How many employees are at HOL's communication division? How many are in HOHI communication division?

d) What IT services are provided to HOL by HOHI? How many IT specialist are employed by HOHI?

RESPONSE:

a) The Human Resources ("HR") services provided by Hydro Ottawa Holding Inc. (the "Holding Company") to Hydro Ottawa include the following:

- Provision of strategic leadership and direction to employees in human resources services, change and organization development, health, safety, environment and business continuity management, and labour relations;
- Preparation and presentation of materials to Board Committees and Board of Directors;
- Provision of strategic leadership and direction in the development and implementation of human resources services, change and organization

development, health, safety, environment and business continuity management, and labour relations strategies, programs, and initiatives and associated metrics;

- Provision of advice regarding the aforementioned strategies, programs, and initiatives and related legislative and regulatory compliance requirements;
- Oversight for the development and implementation of labour relations and collective bargaining strategies, as well as any negotiations with the bargaining agent; and
- Provision of training for staff with trades certification, corporate programs, general corporate software, and legislative requirements.

b) The total number of Hydro Ottawa HR full time equivalents (“FTEs”) in 2021 is 41. The total number of Holding Company HR FTEs in 2021 is two (2).

c) Communication services provided to Hydro Ottawa by the Holding Company are largely the provision of strategic leadership, direction, and guidance as it relates to corporate communications, public affairs, marketing, media, and public relations.

The total number of Hydro Ottawa Communications FTEs in 2021 is 11.7. The total number of Holding Company Communications FTEs in 2021 is three (3).

d) Information Technology (“IT”) services from the Holding Company to Hydro Ottawa include the following:

- The provision of strategic leadership, guidance, and support with regard to the delivery of Information Technology and Information Management (“IT & IM”) objectives and initiatives, including systems security, asset planning, contingency planning, contract management, IT & IM best practices and protocols, associated user training/education, records management, and general technical support;

- The provision of functional programming and analytical operational support with regard to the Enterprise Resource Planning (“ERP”) objectives and initiatives, including monitoring, user security, configuration and change activities, analysis, testing, and deploying and implementing solutions, as well as collaborating with stakeholders and vendors; and
- The provision of technical programming and analytical support with regard to the ERP objectives and initiatives, including monitoring, user security, configuration and change activities, analysis, testing, and deploying and implementing solutions, as well as collaborating with stakeholders and vendors.

There are two (2) IT Specialist FTEs in the Holding Company in 2021.

INTERROGATORY RESPONSE - VECC-89

4.0 -VECC -89

EXHIBIT REFERENCE:

Exhibit 4, Tab 2, Schedule 2

SUBJECT AREA: OM&A

a) Please provide the amounts paid for EDA membership for the years 2016 through 2021 (forecast).

b) Please provide the amounts paid for other corporate memberships.

c) Please provide the amount paid on behalf employees for professional or club memberships. Please indicate whether these amounts are included in the compensation benefits shown in Appendix 2-K.

RESPONSE:

a) Please see Table A for Electricity Distributors Association ("EDA") Membership costs from 2016-2019 (actual) and 2020-2021 (forecast).

Table A – Annual EDA Membership Costs ($'000s)

	Historical				Bridge	Test
	2016	2017	2018	2019	2020	2021
EDA Membership	$115.0	$115.0	$117.3	$119.6	$122.0	$124.4

b) The total amounts paid for other corporate memberships in 2019 was $0.5M.

c) The amount paid on behalf of employees for professional or club memberships was $66K in 2019. These amounts are excluded from the compensation benefits shown in Appendix 2-K.

INTERROGATORY RESPONSE - VECC-90

4.0-VECC-90

EXHIBIT REFERENCE:

Exhibit 4, Tab 2, Schedule 5

SUBJECT AREA: OM&A

a) Does HOL communicate the availability of LEAP funding in its disconnection notices (including telephone calls)?

b) Did HOL as part of its customer engagement attempt to understand whether the availability of LEAP is widely known among its customers and if not how to address any communication problems identified?

RESPONSE:

a) Hydro Ottawa communicates the availability of LEAP funding (including in telephone calls) to customers who may be behind on their electricity bill and facing potential service disconnection.

Disconnection notices, which include LEAP eligibility and application information, are sent to affected customers 14 days prior to disconnection taking place. In addition to the customer disconnection notice, Hydro Ottawa provides affected customers with a 48-hour notice via a telephone auto dialer message that communicates the availability of LEAP as well.

b) The OEB-prescribed LEAP program was not within the scope of Hydro Ottawa's 2021-2025 rate application customer engagement activities. Hydro Ottawa adheres to all mandatory OEB LEAP notification provisions and includes LEAP messaging on its website on a dedicated page focused on Financial Assistance programs.

Hydro Ottawa also developed a brochure, available online or in print, that highlights all financial assistance programs and services available to customers.[1] The availability of financial assistance is also referenced in on-hold and on-bill messaging. In addition, Hydro Ottawa's customer service staff refer to LEAP, along with other customer assistance programs, when speaking with customers who are experiencing difficulty paying their bill.

[1] For a copy of the brochure, please see Attachment VECC-20(A): Hydro Ottawa Brochure - Financial Assistance Programs for Electricity Customers.

INTERROGATORY RESPONSE - VECC-91

5.0-VECC-91

EXHIBIT REFERENCE:

Exhibit 5,

SUBJECT AREA: Cost of Capital

a) Please provide a table showing HOL's rate of return on equity for each year 2015 through 2019.

b) Please provide the corporate (HOHI) equity return for the same period.

RESPONSE:

a) Hydro Ottawa's approved and actual Return on Equity ("ROE") for each year in the 2015-2019 period is shown in Table A.

Table A – 2015-2019 Approved and Actual ROE (Hydro Ottawa)

Year	Approved ROE	Actual ROE[1]	ESM[2] Achieved ROE
2015	9.42%	7.92%	N/A[3]
2016	9.19%	9.80%	9.75%
2017	9.19%	10.10%	10.16%
2018	9.19%	9.14%	9.13%
2019	8.98%	8.82%	Not available[4]
2020	8.98%	Not available	Not available

b) The ROE for Hydro Ottawa Holding Inc. (the "Holding Company") for each year in the 2015-2019 period is shown in Table B below.

[1] The figures presented for Actual ROE are consistent with Hydro Ottawa's Reporting and Record Keeping Requirements ("RRR") filings.
[2] "ESM" stands for Earnings Sharing Mechanism.
[3] In 2015, Hydro Ottawa did not have a custom ESM in place.
[4] The adjustment related to Lost Revenue Adjustment Mechanism is not available at this time.

Table B – 2015-2019 ROE (Holding Company)

Year	ROE
2015	7.83%
2016	8.16%
2017	8.21%
2018	9.08%
2019	6.92%

INTERROGATORY RESPONSE - VECC-92

5.0-VECC-92

EXHIBIT REFERENCE:

Exhibit 1, Tab 3, Schedule 4 / Exhibit 5, Tab 1, Schedule 1

SUBJECT AREA: Cost of Capital

The DBRS Rating Report (September 25, 2019) states:

> *Hydro Ottawa's business risk profile continues to benefit from its stable regulated electricity distribution business in the City of Ottawa (the City; 100% owner of Hydro Ottawa). However, this is partly offset by the Company's growing portfolio of non-regulated electricity generation assets.*

It goes on to say:

> *However, should the Company's key credit metrics deteriorate to a level no longer commensurate with the current rating category, considering the mix of the regulated and non-regulated businesses, further negative rating actions may occur*.

And further..

> *As EBIT contributed by the non-regulated business has breached the previously noted 20% threshold (25.7% in 2018, from 7.5% in 2017), DBRS has introduced the Rating Companies in the Independent Power Producer Industry methodology in addition to the Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry methodology in its assessment of Hydro Ottawa.*

a) Please explain the financial relationship between the non-regulated entities and the regulated utility and what steps HOL is taking to ensure ratepayers are not funding higher than necessary costs of debt due to this relationship.

b) What is the premium between DBRS A as compared to A/Negative rating and a

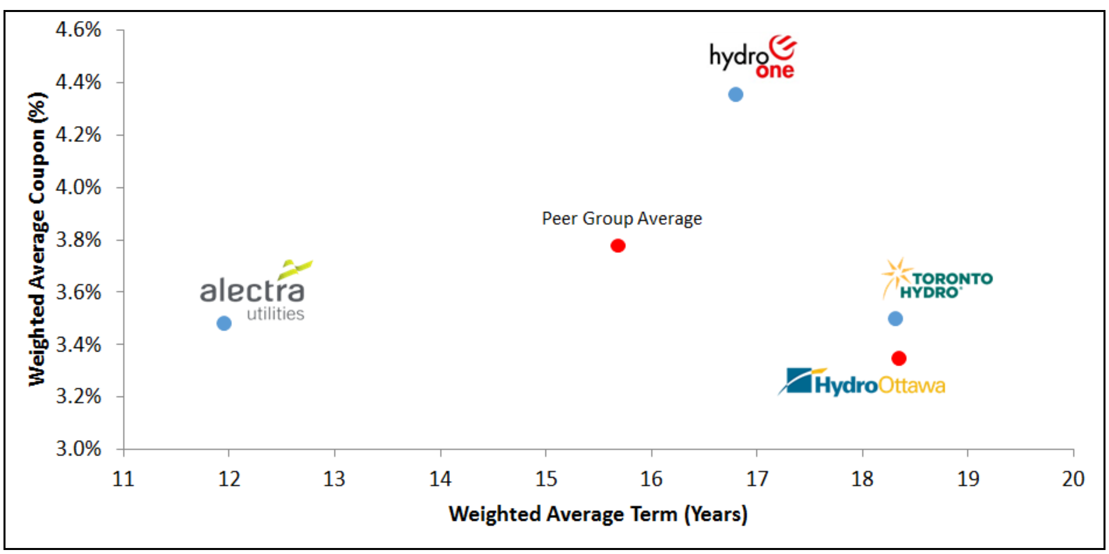
Standard & Poor A as compared to B+++ ratings?

RESPONSE:

a) The regulated company Hydro Ottawa Limited is a wholly-owned subsidiary of Hydro Ottawa Holding Inc. (the "Holding Company"). The non-regulated entities are also owned wholly, or in part, by the Holding Company. There is no financial relationship between the regulated and wholly owned non-regulated entities, other than having the same ultimate ownership. It is important to note that the growth in the non-regulated business has been largely financed at the project level and not through the Holding Company. This project debt is non-recourse to the Holding Company.

As noted in UPDATED Exhibit 5-1-1: Cost of Capital and Capital Structure, Hydro Ottawa continues to use a financing approach whereby funding is received through the Holding Company. This approach is beneficial to ratepayers and can be seen in the long average tenor and low weighted average cost of debt overall for Hydro Ottawa when compared to other peer utilities as shown in Figure A.

Figure A – Debt Cost of Capital - Weighted Average Coupon vs. Weighted Average Term



Source: Bloomberg LP

b) Future bond issuance interest rates will be dependent on the underlying Bank of Canada rates as well as the spreads or risk premium required by the capital markets. These spreads will depend on many factors, including the financial risks of the company itself, new issuance concessions, current geopolitical events, investment climate, etc. While these parameters ultimately determine the “risk premium” of a given issuance, within the A to A- rating category, there is usually very little difference in the spreads. Hydro Ottawa does not anticipate any material change in its risk profile perceived by the markets if the rating changes from A to A-. Through consultation with the Holding Company’s investment bankers, the impact on credit spreads as a result of a potential credit rating downgrade by DBRS from “A” to “A (low)” has been estimated to be less than 5 basis points.

Please note that on January 13, 2020, S&P Global Ratings (“S&P”) withdrew its “BBB+” long-term issued credit rating on the Holding Company. The rating was withdrawn by S&P at the Holding Company’s request. At the time of the withdrawal, the outlook was stable.

INTERROGATORY RESPONSE - VECC-93

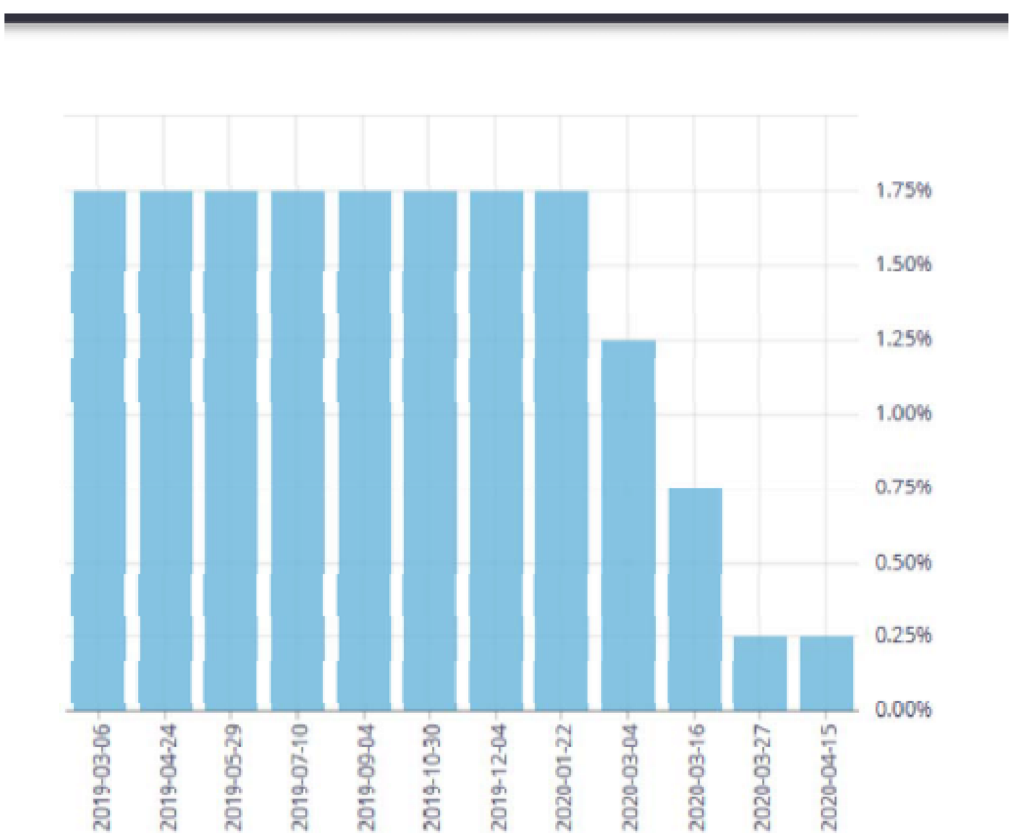
5.0-VECC-93

EXHIBIT REFERENCE:

Exhibit 1, Tab 3, Schedule 4 / Exhibit 5, Tab 1, Schedule 1

SUBJECT AREA: COVID-19

In response to the pandemic and large drop in oil prices affecting the Canadian economy the Bank of Canada has significantly moved to ease monetary policy (as shown in the graph taken from the Bank's website - www.bankofcanada.ca/core-functions/monetary-policy/key-interest-rate/)



a) Given events does HOL agree that economic forecasts completed prior to the pandemic (i.e. February 2020) are largely outdated. If not please explain why these forecasts should be considered reliable.

b) What efforts has HOL made to recast the forecast yields for long-term debt (e.g. Tables 2, 3 & 4) in light of the current economic downturn?

c) What is the most recent Canada Bond forecast that has been reviewed by HOL or HOHI? Please provide that forecast.

RESPONSE:

a) Please see parts (c) and (d) of the response to interrogatory SEC-1 for Hydro Ottawa's position on the validity of forecasts completed prior to the COVID-19 pandemic and an explanation of why these forecasts should be considered reliable.

b) Please see the response to interrogatory OEB-151 for a refreshed long-term debt yield forecast (UPDATED Exhibit 5-1-1: Cost of Capital and Capital Structure Tables 2 - 4) using the April 2020 Long-Term Consensus Forecast.

c) Please see the response to part (b) above.

INTERROGATORY RESPONSE - VECC-94

5.0-VECC-94

EXHIBIT REFERENCE:

Exhibit 5, Tab 1, Schedule 1

SUBJECT AREA: COVID-19

a) Given the present economic uncertainties why would it not be in the best interest of ratepayers to have an annual adjustment made to the cost capital components of the CPEF?

RESPONSE:

a) Hydro Ottawa is not able to provide an update for the impact of the COVID-19 pandemic. At this time, there is not enough information, analysis, or understanding of the potential impacts of the pandemic to accurately forecast what the impact on the 2021-2025 timeframe may be. It is expected that any impact will be mainly with respect to 2020 results. Hydro Ottawa's expectations are that the forecasts for 2021-2025 need not materially change. As necessary, the Earnings Sharing Mechanism, Capital Variance Account, and Lost Revenue Adjustment Mechanism will mitigate the impact on customers over the 2021-2025 period. In addition, the OEB has established three deferral accounts to deal with the incremental costs/lost revenues in 2020 of the impacts associated with the COVID-19 pandemic.[1]

[1] https://www.oeb.ca/sites/default/files/OEBLtr-Accounting-Order-COVID-19-Emergency-20200325.pdf.

INTERROGATORY RESPONSE - VECC-95

5.0-VECC-95

EXHIBIT REFERENCE:

Exhibit 5, Tab 1, Schedule 1

SUBJECT AREA: Cost of Capital

a) Please explain why the return to common equity shown in Appendix 2-OA for 2020 and 2021 are 8.88% rather than the 8.52% value provided in the Board's letter of October 31, 2019? Please calculate the revenue requirement adjustment using 8.52%.

RESPONSE:

a) The return on common equity rate of 8.98% as shown in UPDATED Attachment 5-1-1(A): OEB Appendix 2-OA - Capital Structure and Cost of Capital for 2020 is per the Approved Settlement Agreement from Hydro Ottawa's 2016 rate application.[1] As per the Approved Settlement Agreement, the short-term debt and Return on Equity ("ROE") were to be updated in Fall 2018 using the prescribed rates for 2019. These rates were then to stay in effect for the final two years of the application's term (2019 and 2020).

The return on common equity rate of 8.88% as shown in Appendix 2-OA for 2021 has been forecast using the OEB's formulaic calculation, as described in UPDATED Exhibit 5-1-1: Cost of Capital and Capital Structure.

While the 8.52% ROE value outlined in the OEB's letter dated October 31, 2019 is not the premise of Hydro Ottawa's ROE calculations for 2021, the requested calculation has been shown in Table A below.

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Approved Settlement Proposal*, EB-2015-0004 (December 7, 2015).

Table A – 2021 Revenue Deficiency/Sufficiency - Revenue Requirement Adjustment Using 8.52% ROE ($'000s)

	2021 8.88% ROE	2021 8.52% ROE
Interest Expense	$24,442	$24,442
Return on Equity	$43,716	$41,943
Distribution Expenses (not including amortization)	$93,923	$93,923
Amortization	$52,333	$52,333
Payment in Lieu of Taxes	$2,224	$2,224
Service Revenue Requirement	**$216,638**	**$214,865**

INTERROGATORY RESPONSE - VECC-96

5.0-VECC-96

EXHIBIT REFERENCE:

Exhibit 5, Tab 1, Schedule 1

SUBJECT AREA: Cost of Capital

a) At Appendix 2-OB HOL calculated the long-term debt for the 2021 test year at 3.35% however this amount is calculated on the over leveraged amount of long-term debt (i.e. 737.5M rather than $689.2 M allowable). Please recalculate this debt rate removing the unallowable amount (i.e. from $50.0M @ 4.97%).

b) Please provide the 2021 revenue requirement adjustment of this change.

RESPONSE:

a) Hydro Ottawa's capital structure, cost of capital, and debt instruments shown in Attachments 5-1-1(A): OEB Appendix 2-OA - Capital Structure and Cost of Capital and 5-1-1(B): OEB Appendix 2-OB - Debt Instruments have been calculated as per OEB Filing Requirements. Hydro Ottawa is not aware of any further OEB guidance to calculate the cost of long-term debt in a different fashion or as suggested by this interrogatory.

However, in an effort to present an illustrative scenario in response to the interrogatory, Hydro Ottawa has prepared Attachment VECC-96(A): Appendix 2-OA - Capital Structure and Cost of Capital (Illustrative Example) based on the following comments and assumptions.

Hydro Ottawa notes the $50M promissory, bearing interest at 4.968% and maturing on December 19, 2036, is the first long-term debt issuance outstanding and was issued in

2006 when the applicable OEB deemed rate for long-term debt was 5.9% and Hydro Ottawa's debt was consistent with the deemed capital structure. Accordingly, to illustrate the weighted cost of long-term debt at 56%, it would be inappropriate to adjust the weighted average cost of long-term debt in Appendix 2-OB by removing the $50M promissory to achieve the desired calculation.

For the purpose of providing this response, Hydro Ottawa has removed or prorated the principal of the last debt issuances in Appendix 2-OB such that the total long-term debt in 2021 reflects the 56% or $689.2M shown in Appendix 2-OA, as referenced in this interrogatory. This approach removes a portion of the long-term debt issued in 2019 that technically pushed it past 56% as well as the debt contemplated to be issued in 2021. The effect is minimal on the long-term debt weighted average,, as it decreases to 3.34%.

Hydro Ottawa's approach to long-term debt is beneficial to ratepayers and can be seen in the long average tenor and low weighted average cost of debt overall for the utility when compared to other peer utilities, as shown in Figure A of the response to interrogatory VECC-92.

b) The revenue requirement calculated as a result of the illustrative example described in part (a) above is shown in Table A.

Table A – Revenue Deficiency/Sufficiency for 2021 - Illustrative Example ($'000s)

	2021 per Updated 2-OA	2021 as Illustrated
Long-term Interest Expense	$23,089	$23,020
Short-term Interest Expense	$1,354	$1,354
Return on Equity	**$43,716**	**$43,716**
Distribution Expenses (not including amortization)	**$93,923**	**$93,923**
Amortization	**$52,333**	**$52,333**
Payment in Lieu of Taxes	**$2,224**	**$2,224**
Service Revenue Requirement	**$216,638**	**$216,569**

Year 2021 Test Year

Adjusted in response to IR VECC-96

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Promissory Note	Hydo Ottawa Holding Inc.	Affiliated	Fixed Rate	20-Dec-06	30 years	$ 50,000,000	4.97%	$ 2,484,000.00	$50.0M Promissory Note
2	Promissory Note	Hydo Ottawa Holding Inc.	Affiliated	Fixed Rate	14-May-13	30 years	$ 107,185,000	3.99%	$ 4,277,753.35	$107.185M Promissory Note
3	Promissory Note	Hydo Ottawa Holding Inc.	Affiliated	Fixed Rate	9-Feb-15	10 years	$ 138,667,000	2.61%	$ 3,624,755.38	$260.0M, in aggregate, Promissory Notes
4	Promissory Note	Hydo Ottawa Holding Inc.	Affiliated	Fixed Rate	9-Feb-15	30 years	$ 121,333,000	3.64%	$ 4,415,307.87	
5	Promissory Note	Hydo Ottawa Holding Inc.	Affiliated	Fixed Rate	25-Jun-15	10 years	$ 15,999,000	2.61%	$ 418,213.86	$30.0M, in aggregate, Promissory Notes
6	Promissory Note	Hydo Ottawa Holding Inc.	Affiliated	Fixed Rate	25-Jun-15	30 years	$ 14,001,000	3.64%	$ 509,496.39	
7	Promissory Note	Hydo Ottawa Holding Inc.	Affiliated	Fixed Rate	16-Oct-19	10 years	$ 84,709,547	2.66%	$ 2,253,273.96	$242.0M, in aggregate, Promissory Notes
8	Promissory Note	Hydo Ottawa Holding Inc.	Affiliated	Fixed Rate	16-Oct-19	30 years	$ 157,317,731	3.21%	$ 5,049,899.16	
Total							$ 689,212,278	3.34%	$ 23,019,690.09	

INTERROGATORY RESPONSE - VECC-97

5.0-VECC-97

EXHIBIT REFERENCE:

Exhibit 5, Tab 1, Schedule 1

SUBJECT AREA: Cost of Capital

a) A number of the notes contain repayment terms which allow Hydro Ottawa Limited to "*at any time, repay in whole or in part the Principal Amount or the amount remaining unpaid*.", i.e. are a callable bond. Using Appendix 2-OB please indicate which loans contain callable provisions.

b) The Board has determined that affiliate debt should attract the lower of the actual rate or the deemed long-term debt rate of 3.21%. All HOL's debt is from its affiliate Hydro Ottawa Holding Inc. Please explain why therefore the long-term rate used for the purpose of establishing 2021 rates is not 3.25% rather than the 3.35% proposed.

c) Given the historical low interest rates available why is HOL not choosing to refinance its portfolio of callable bonds at lower interest rates?

RESPONSE:

a) Please refer to Attachment VECC-97(A): Appendix 2-OB (Annotated) for a listing of which promissory notes issued by Hydro Ottawa contain callable/redemption provisions.

b) The 3.21% long-term rate referenced is the deemed rate issued by the OEB in its letter of October 31, 2019 for rate applications with rates effective in 2020. Hydro Ottawa issues debt through Hydro Ottawa Holding Inc. ("Holding Company") on a "pass through" basis, which reflects third-party embedded/actual debt with fixed rates, terms, and maturity achieved by the Holding Company in the capital markets. These are the rates

Hydro Ottawa has used since its first issuance in 2005 and which have all been at, or lower than, the deemed rate established by the OEB at the time of the debt issuance.

For example, the most recent Hydro Ottawa issuance was on October 16, 2019. As outlined in UPDATED 5-1-1: Cost of Capital and Capital Structure, the rates used were based on the prevailing BMO Capital Markets weekly indicative rates for the Holding Company with no allowance for issuance costs. The two notes issued were 10-year and 30-year tenors bearing fixed interest rates of 2.66% and 3.21%, respectively. With this issuance, Hydro Ottawa secured long-term financing at a time when the Government of Canada 10-year and 30-year bond yields were close to historical lows. The 3.21% rate for the 30-year note aligns with the OEB's deemed long-term debt rate issued two weeks later.

In Attachment 5-1-1(B): OEB Appendix 2-OB - Debt Instruments, the long-term debt rate of 3.35% shown for 2021 reflects the weighted average of all existing embedded long-term debt plus the forecast debt as of December 31, 2021. As noted, all of the existing embedded debt has been issued at a rate equal to, or lower than, the deemed debt rate at the time of its issuance.

c) As shown in Attachment VECC-97(A): Appendix 2-OB (Annotated), all of Hydro Ottawa's fixed-term promissory notes contain early call/redemption provisions. These call provisions mirror the call provisions in the debentures issued by the Holding Company via the capital markets and passed on to Hydro Ottawa. The call/redemption provisions are structured and priced to keep bond holders whole and are generally punitive in nature to deter the issuer from early redemption. If Hydro Ottawa were to redeem a particular promissory note by exercising its right to early repayment, and subsequently issue a new promissory note at the prevailing rate available in the market, it will incur a financial loss on redemption. Accordingly, Hydro Ottawa has not elected to refinance its portfolio of existing bonds.

INTERROGATORY RESPONSE - VECC-98

7.0 – VECC –98

EXHIBIT REFERENCE:

Updated Exhibit 7, Tab 1, Schedule 1, page 2

SUBJECT AREA: Cost Allocation

Preamble:

The Application states:

"Hydro Ottawa was unable to obtain the hourly load profile data required to derive updated load profiles for this Application. As a result, demand data figures for the 2021 Cost Allocation Model have been calculated based on hourly demand figures used in previous rate applications, adjusted to the 2021 monthly load profile and customer count forecasts."

"Hydro Ottawa confirms that it has a plan in place to develop updated hourly load profiles to comply with the current Filing Requirements."

a) What hourly load profile data was HOL unable to obtain and why?

b) What is HOL's plan with respect to developing updated load profiles?

RESPONSE:

a) Hydro Ottawa has started the process to gather and review hourly meter data, as well as smart meter and interval meter data for all metered classes for the purpose of updating load profiles. As per the OEB's Chapter 2 Filing Requirements, if updated load data is not available, the distributor should put a plan in place to update load profiles for its next cost of service application.

b) Hydro Ottawa plans to use three years of customer hourly metered data summarized by rate class to develop updated load profiles for its next rebasing proceeding.

INTERROGATORY RESPONSE - VECC-99

7.0-VECC-99

EXHIBIT REFERENCE:

Updated Exhibit 7, Tab 1, Schedule 1, page 1

SUBJECT AREA: Cost Allocation

a) Please provide the derivation of the Billing & Collecting weighting factors used in Tab I5.2 of the Cost Allocation model.

b) Please provide the derivation of the Services weighting factors used in Tab I5.2 of the Cost Allocation model.

c) Please confirm that each of the GS and Large User customers only has one HOL-owned meter. If not confirmed please revise the customer counts used in Tabs I7.1 and I7.2 accordingly.

d) Do any of the GS or Large User customers have customer-owned meters that are read by HOL for billing purposes? If yes, which customer classes and how many for each?

RESPONSE:

a) Please see the response to interrogatory OEB-155.

b) Please see the response to interrogatory OEB-155.

c) Hydro Ottawa confirms that customer counts on Tabs I7.1 and I7.2 of the Cost Allocation Model are appropriate. While Large User customers typically have more than one meter, the cost per meter for this group has been established based on a typical meter configuration.

d) Hydro Ottawa does not read any customer-owned meters for billing purposes.

INTERROGATORY RESPONSE - VECC-100

7.0-VECC-100

EXHIBIT REFERENCE:

Updated Exhibit 7, Tab 1, Schedule 1, pages 1-2

Updated 2021 Cost Allocation Model, Tabs I6.2 and I8

SUBJECT AREA: Cost Allocation

a) It is noted that in Tab I6.2 the Residential Secondary Customer Base is less than the Primary Customer Base. Please explain why this is the case.

b) Please explain why, in Tab I6.2, the Residential LT Customer Base is not equal to the Secondary Customer Base.

c) It is noted that in Tab I8 the Residential Secondary NCP4 value equals the Primary NCP4 even though in Tab I6.2 the Secondary Customer Base is less than the Primary Customer Base. Please reconcile.

d) Are any of HOL's residential customers located in multi-residential building (e.g. apartments or condominiums) where the transformer and/or the service connection to the building is not owned by HOL but rather by the building owner (e.g. the apartment building owner or the condominium corporation)?
    i) If yes, how many such Residential customers were there in 2019?
    ii) It yes, do the Residential Secondary and LT Customer counts in Tab I6.2 and the Residential Secondary and LT NCP4 values in Tab I8 reflect these circumstances?

e) Are any of HOL's GS customers located in commercial/industrial malls (e.g. shopping centres) where the transformer and/or the service connection to the "mall" is not owned by HOL but rather by the building complex (e.g. the mall owner?

i) If yes, for each GS class, how many such GS customers were there in 2019?

ii) It yes, do the respective GS class Secondary and LT Customer counts in Tab I6.2 and the GS class Secondary and LT NCP4 values in Tab I8 reflect these circumstances?

f) It is noted that in Tab I6.2 the GS<50 Secondary Customer Base is less than the Primary Customer Base. Please explain why this is the case.

g) Please explain why, in Tab I6.2, the GS<50 LT Customer Base is not equal to the Secondary Customer Base.

h) It is noted that in Tab I8 the GS<50 Secondary and LT NCP4 values both equal the Primary NCP4 value even though in Tab I6.2 the LT and Secondary Customer Bases are both less than the Primary Customer Base. Please reconcile.

i) Please explain why, in Tab I6.2, the GS1500-4999 LT Customer Base is less than the Secondary Customer Base.

j) Please explain why, in Tab I8, there is no Secondary NCP4 value for the GS1500-4999 class when in Tab I6.2 there are 65 customers in the GS1500-4999 Secondary Customer Base.

k) Please explain why, in Tab I6.2, the Large User LT Customer Base is less than the Secondary Customer Base.

l) Please explain why, in Tab I8, there is no Secondary NCP4 value for the Large User class when in Tab I6.2 there are 9 customers in the Large User Secondary Customer Base.

m) Please explain why, when there are 3 GS1500-4999 Standby customers per Tab

I6.2, Tabs I7.1 and I7.2 only show 2 meters for these customers.

n) Please explain why, for the GS1500-4999 Standby class, Tab I6.2 shows zero for LT Customer Base whereas Tab I8 shows a positive value LT NCP4 value for the class.

o) For each of the 3 GS1500-4999 Standby customers, please explain what HOL facilities/assets are used to serve the customers.

RESPONSE:

a) Please see the response to interrogatory OEB-157 part (a).

b) Please see the response to interrogatory OEB-157 part (a).

c) Please see the response to interrogatory OEB-157 part (a).

d) Please see the response to interrogatory OEB-157 part (b).

e) Please see the response to interrogatory OEB-157 part (c).

f) Please see the response to interrogatory OEB-157 part (a).

g) Please see the response to interrogatory OEB-157 part (a).

h) Please see the response to interrogatory OEB-157 part (a).

i) The GS 1,500-4,999 kW class does not have secondary customers. The customer count originally provided includes all customers that do not own secondary equipment. However, the remaining customers should not be included because they do not use any secondary equipment. The secondary customer count has been revised in an updated cost allocation model, which is included as excel Attachment OEB-38(A): Updated OEB Workform - Cost Allocation Model.

j) Please see the response to part (i) above.

k) Large User customers do not use Hydro Ottawa secondary equipment. As a result, the secondary customer count has been revised in the updated cost allocation model, as found in excel Attachment OEB-38(A).

l) Please see the response to part (k) above. Refer to excel Attachment OEB-38(A) for an updated cost allocation model.

m) This has been corrected. Please see the updated cost allocation model, filed as excel Attachment OEB-38(A).

n) The inconsistency is due to a timing mismatch between the information used for customer counts and the hourly demand data used to derive demand allocators. In 2004, a Standby customer used line transformer assets (according to hourly data from the 2006 CAIF). More recent customer information shows that no Standby customers currently use those assets. As such, Line Transformer demand has been removed from the Standby class in the updated cost allocation model in excel Attachment OEB-38(A).

o) Hydro Ottawa maintains sufficient power in its distribution grid to service Standby customers in the event their supply cannot be used. As such, GS 1500-4999 Standby customers use similar facilities/assets as the GS 1500-4999 customers without Standby. The fixed monthly service charge compensates Hydro Ottawa for the administration related to standby services while the volumetric rate compensates the utility for the reserved capacity requirement.

INTERROGATORY RESPONSE - VECC-101

7.0-VECC-101

EXHIBIT REFERENCE:

Updated Exhibit 7, Tab 1, Schedule 1, page 4

SUBJECT AREA: Cost Allocation

a) Please outline the methodology used to determine the proposed increases in the revenue to cost ratios for the GS50-1499, GS1500-4999, Large User and Sentinel Lighting classes.

RESPONSE:

a) Please see pages 9-12 of Attachment 7-1-1(B): Hydro Ottawa Cost Allocation Report for a discussion of the methodology utilized to bring all customer rate classes within their approved revenue-to-cost ranges.

INTERROGATORY RESPONSE - VECC-102

8.0-VECC-102

EXHIBIT REFERENCE:

Updated Exhibit 8, Tab 1, Schedule1, page 9

Updated Exhibit 8, Tab 10, Schedule 1, Attachment A

SUBJECT AREA: Rate Design

Preamble:

The Application states:

"*Effective April 1, 2015, customers with customer-owned transformers installed after November 1, 2000 were no longer eligible to receive the credit. The TOC will be discontinued for customers who own transformers that were installed prior to November 1, 2000 either when the customer-owned transformer has been replaced, or after November 1, 2025 – whichever occurs first.*"

a) Are customers with customer-owned transformers installed after November 1, 2000 currently (i.e., in 2020) not receiving any transformer ownership credit?

b) If yes, why is there no reference to this limitation on the 2020 approved tariff schedule?

c) Please explain why it is appropriate to discontinue offering the TOC to customers with customer-owned transformers.

RESPONSE:

a) Upon further investigation, Hydro Ottawa did not stop providing the ownership credit to all affected customers with customer-owned transformers installed after November 1, 2000, per the Conditions of Service - Version 5 (effective April 1, 2015).

b) The approved tariff schedule follows a standard format and wording established by the OEB. Conditions for qualification for the Transformer Ownership Credit are described in Hydro Ottawa's Conditions of Service - Version 7 as quoted above and presented in UPDATED Exhibit 8-1-1: Fixed/Variable Proportion.

c) Please see the response to interrogatory OEB-162, parts (a) and (c).

INTERROGATORY RESPONSE - VECC-103

8.0-VECC-103

EXHIBIT REFERENCE:

Exhibit 8, Tab 4, Schedule 1, pages 1-2

SUBJECT AREA: Rate Design

a) Please clarify whether: i) HOL is seeking approval of retail services charges for 2021-2025 as set out in Table 1 or ii) HOL intends to adjust its current (2020) retail service charges in accordance with the Board's November 29, 2018 Decision (EB-2015-0304) using the Board's annual inflation rate.

b) If HOL is not proposing to adjust its retail service charges in accordance with EB-2015-0304, please explain why.

RESPONSE:

a) Please see the response to interrogatory OEB-164.

b) Please see part (a) above.

INTERROGATORY RESPONSE - VECC-104

8.0-VECC-104

EXHIBIT REFERENCE:

Updated Exhibit 8, Tab 7, Schedule 1, pages 3-7 & 9 and Attachment A

SUBJECT AREA: Specific Service Charges

a) Please outline the circumstances which would lead to a customer requesting an Easement Certificate for Unregistered Easements and why this is considered a service over and above HOL's standard level of service offerings.

b) The proposed 2021 charges for Arrears Certificate and Easement Certificate for Unregistered Easements are both materially less than the cost to provide the respective services (per Attachment A, pages 1 & 2). Please explain why.

c) It is noted that the costing for the Account Set Up Charge is based on a 50/50 weighting of the service being provided by Internal Staff versus the Contact Centre (per Attachment A, page 6). What is the basis for the 50/50 weighting and is it expected change over time (i.e., 2021-2025)?

d) Please explain the circumstances that would give rise to applying the Reconnect at Meter (New Account) – Regular Hours charge? In doing so please explain why, if it is a new account and the "new customer" was not responsible for the original disconnection, the new customer should be required to pay the charge.

e) What is the incremental cost of equipping HOL's AMI such that disconnects and reconnects can be done remotely and what proportion of HOL's meters are so equipped?

f) With respect to the proposed Reconnection at the Pole charge, please explain why the Regular Hours Charge is less than cost while the After Regular Hours Charge is more than cost (per Attachment A, pages 9-10).

g) With respect to the Specific Access to Power Poles – Wireline Attachments Charge please clarify whether: i) HOL is seeking approval of charges for 2021-2025 as set out in Table 1 or ii) HOL intends to adjust the approved 2020 charge in accordance with the Board's March 22, 2018 Decision (EB-2015-0304) using the Board's annual inflation rate.

RESPONSE:

a) The circumstances which would lead to a customer requesting an Easement Certificate for Unregistered Easements would include, but not be limited to, the purchase of a property, renovations to an existing dwelling or building, any new structure, tree trimming, and general property access. This request is most often received through a customer's lawyer.

   For those services for which the utility charges a fee, Hydro Ottawa does so to recover the costs associated with the services being offered to the party requesting the service. In this way, Hydro Ottawa is not socializing those costs across all customers.

b) For both of these services, the main driver is the cost associated with internal labour. Through the optimization of process flow and efficiencies achieved through digitalization, it is anticipated that the time involved to perform these services will, in turn, reduce Hydro Ottawa's internal costs.

c) The 50/50 weighting was based on information available at the time of completing the internal costing. It represents a balance between Hydro Ottawa's internal costs and those of its Customer Contact Centre service provider. While the weighting may change during the next five years due to increased use of the Customer Contact Centre service provider and increased automation, the service charge will remain constant during the 2021-2025 rate period.

d) A Reconnect at Meter (New Account) – Regular Hours charge would be applied if the service was previously disconnected. Reconnect charges are applied to all services that have been disconnected for non-payment or for periods in which there is no confirmed account holder to accept responsibility for the service. Reconnect charges are not applied to eligible low-income customers, in accordance with section 4.2.5.3 of the *Distribution System Code*.

e) The incremental cost of a remote disconnect meter is $44.48. The proportion of meters equipped with disconnect/reconnect functionality is 11.03% of the total meter population.

f) The Regular Hours Charge is less than cost, as Hydro Ottawa is currently optimizing the process to introduce efficiencies that will reduce internal costs. For the After Regular Hours Charge, Hydro Ottawa will continue to adopt the standard provincial rate for 2020 and increase by the annual escalation factor between 2021 and 2025.

g) As noted in the response to interrogatory OEB-164, Hydro Ottawa intends to adjust the approved 2020 Specific Access to Power Poles – Wireline Attachments Charge using the OEB's annual inflation rate, in accordance with applicable policy directives issued by the OEB in 2018.[1]

[1] Ontario Energy Board, *Report of the Ontario Energy Board - Wireline Pole Attachment Charges*, EB-2015-0304 (March 22, 2018).

INTERROGATORY RESPONSE - VECC-105

8.0-VECC-105

EXHIBIT REFERENCE:

Updated Exhibit 8, Tab 7, Schedule 1, pages 8-9

SUBJECT AREA: Specific Service Charges

a) Is HOL aware of any other Ontario electricity distributor that has received approval for a Standard Supply Service Administrative Charge other than $0.25? If yes, please provide the relevant case number.

b) Is HOL aware of any direction/decision by the Board to revise the current generic $0.25 SSS Administrative Charge?

c) The Board's Chapter 2 Filing Guidelines (Section 2.8.5) state that "*These rates are set by the OEB on a generic (i.e. province-wide) basis. Applicants should refer to the most recent rate order for the current approved rate. Distributors wishing to apply for a rate other than the generic rate set by the OEB must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate*". Please indicate what HOL's specific circumstances are that warrant a rate different from the generic province-wide rate.

RESPONSE:

a) Hydro Ottawa is not aware of any other Ontario electricity distributor that has applied for or received approval for a Standard Supply Service Administration ("SSS") charge other than $0.25.

b) The OEB is currently completing a comprehensive policy review of all its miscellaneous service charges.[1] Hydro Ottawa anticipates that this will result in a decision to revise the current generic $0.25 SSS Charge.

c) Please see the response to interrogatory OEB-167.

[1] Ontario Energy Board, Letter re: Review of Miscellaneous Rates and Charges, EB-2015-0304 (November 5, 2015).

INTERROGATORY RESPONSE - VECC-106

8.0-VECC-106

EXHIBIT REFERENCE:

Exhibit 8, Tab 8, Schedule 1

Exhibit 2, Tab 3, Schedule 1, page 8 (Table 10)

SUBJECT AREA: Rate Design

a) Please confirm that Exhibit 8, Tab 8, Schedule 1 is unchanged from the original Application.

b) With respect to Table 2 (Exhibit 8, Tab 8, Schedule 1), how much of the 2019 increase in LV expense was due to an increase in HONI's ST rates?

c) Please provide the derivation of the 2021-2025 LV Expenses set out in Table 3.

d) Please confirm that based on HOL's proposal the RTSRs in column A of Tables 5-8 would be updated annually but the charge determinants and annual LV expenses would not change.

RESPONSE:

a) Hydro Ottawa confirms that Exhibit 8-8-1: Low Voltage Service Rates is unchanged from the original Application.

b) Upon review of Exhibit 8-8-1: Low Voltage Service Rates, Hydro Ottawa has noticed that Table 2 as originally submitted was not presented correctly. Table 2 has been revised below.

Table 2 – AS ORIGINALLY SUBMITTED – LV Expenses 2016-2020 ($'000s)

	Historical Years			Bridge Years	
	2016	2017	2018	2019	2020
LV Expenses	$358,024	$345,895	$350,336	$428,000	$434,000

Table 2 – AS REVISED – LV Expenses 2016-2020 ~~($'000s)~~

	Historical Years			Bridge Years	
	2016	2017	2018	2019	2020
LV Expenses	$358,024	$345,895	$350,336	$428,000	$434,000

Table A is an updated version of Table 2 above, with 2019 actuals included.

Table A – LV Expenses 2016-2020

	Historical Years				Bridge Year
	2016	2017	2018	2019	2020
LV Expenses	$358,024	$345,895	$350,336	$333,304	$434,000

In 2019, the Hydro One Networks Inc. ("HONI") volumetric rate for Connection to Common ST Lines ("Common ST Lines") increased by 19.8% and the volumetric rate for Connection to High Voltage Distribution Station ("HVDS") low-voltage delivery charge increased by 12.3%. These charges are billed based on monthly kW demand at HONI delivery points feeding into Hydro Ottawa's distribution system. Other HONI monthly charges included in the Uniform System of Accounts ("UsofA") Account 4750 Charges - LV decreased, as described below. Please note that the 2019 actuals amount only includes the increased rates implemented as of July 1, 2019.[1]

On a monthly basis, HONI charges its Sub-Transmission ("ST") customers a Service Charge (per delivery point), Meter Charge (per meter), and charge for connection to Specific ST Lines (per km). As set out in the OEB's *Accounting Procedures Handbook*,

[1] Ontario Energy Board, *Interim Rate Order*, EB-2017-0046 (June 6, 2019), page 2.

these charges are to be included in Account 4750 - LV Charges.[2] In 2019, the HONI Service Charge also increased by 10.9%. In contrast, the Meter Charge decreased by 25.2% and Specific ST Lines charge decreased by 40.9%. The decrease in Meter Charge and Specific ST Lines charge largely offset the increase in per kW volumetric rates noted above.

When forecasting the 2019 Bridge amount, Hydro Ottawa derived the amount based on applying the estimated increased rates for HVDS low-voltage delivery charge and Common ST Lines charge to the forecast annual kW. Similar to 2019, the methodology used for the estimate in the Application, as originally submitted and as described in part (c) below, has likely resulted in the Test Years 2021-2025 LV Expense being overestimated annually by approximately $80K. This amount reflects Hydro Ottawa using the same method as the HVDS low-voltage delivery charge and Common ST Lines charge to inflate the Service Charge, Meter Charge, and Specific ST Line Charge in 2022-2025. Further details can be found in UPDATED Exhibit 2-3-1: Working Capital Requirement.

c) Hydro Ottawa set out the forecast of LV Expenses in UPDATED Exhibit 2-3-1: Working Capital Requirement and Exhibit 8-8-1: Low Voltage Service Rates based on the 2018 expense. The 2018 historical amount from Table 2 in Exhibit: 8-8-1: Low Voltage Service Rates was separated into amounts based on charges for HVDS Connection to low-voltage delivery and Connection to Common ST Lines. The allocated dollars were then divided by the 2018 approved rates to derive an estimated annual kW for each charge. Please see the estimated kW outlined below in Table B.

[2] Ontario Energy Board, *Accounting Procedures Handbook Frequently Asked Questions* (October 2009), pages 15-16.

Table B – Estimated Annual Low Voltage kW

	2018 Expense	2018 Rate[3]	Estimated kW
Connection to HVDS-Low Voltage Delivery	$128,929	$3.3552	38,426
Connection to Common ST Lines	$221,407	$1.2052	183,710
TOTAL	**$350,336**		

Hydro Ottawa has kept the estimated annual kW constant for 2021-2025. To calculate the forecast expense, the annual kW were multiplied by the estimated rates for each charge, as set out in UPDATED Exhibit 2-3-1: Working Capital Requirement, Table 10. The forecast expense by charge has been provided in Table C below.

Table C – 2021-2025 Forecast LV Expense

	2021	2022	2023	2024	2025
Connection to HVDS-Low Voltage Delivery	$146,201	$148,467	$150,769	$153,106	$155,479
Connection to Common ST Lines	$272,883	$277,113	$281,408	$285,770	$290,199
TOTAL[4]	**$419,084**	**$425,580**	**$432,177**	**$438,875**	**$445,678**

d) Hydro Ottawa confirms that the RTSRs in column A of Tables 5-8 would be updated annually and the charge determinants and annual LV expenses would not change. The variance between the actual and estimated costs will be recorded into their respective Group 1 Accounts.

[3] Ontario Energy Board, *Decision and Order,* EB-2016-0081 (December 21, 2016), Schedule A, page 10.
[4] Totals may not sum due to rounding.

INTERROGATORY RESPONSE - VECC-107

8.0-VECC-107

EXHIBIT REFERENCE:

Updated Exhibit 8, Tab 9, Schedule 1

SUBJECT AREA: Rate Design

a) With respect to Appendix 2-R please indicate the kWh pertaining to distributed generation directly connected to HOL's distribution system and confirm that they are included in A(2) for each year.

RESPONSE:

a) Yes, the kWh pertaining to distributed generation directly connected to Hydro Ottawa's distribution system are included in the updated version of Appendix 2(R) - row A(2) for each year, as submitted in UPDATED Attachment 8-9-1(A): OEB Appendix 2-R - Loss Factors.

Please see Table A for 2014-2019 kWh. These amounts do not include the kWh for wholesale-metered generation or net-metered generation that is directly connected to Hydro Ottawa's distribution system.

Table A – 2014-2019 "Wholesale" kWh Delivered to Distributor - Distributed Generation

Appendix 2(R) - A(2)	2014	2015	2016	2017	2018	2019
Distributed Generation	139,058,540	167,616,984	172,567,674	183,521,415	330,368,674	330,902,155

INTERROGATORY RESPONSE - VECC-108

8.0-VECC-108

EXHIBIT REFERENCE:

Updated Exhibit 8, Tab 10, Schedule 1, Attachment A, pages 11 and 31

SUBJECT AREA: Rate Design

a) Please explain how the monthly billing demand for Standby Power Service is determined.

RESPONSE:

a) Hydro Ottawa's approach to determining billing demand for Standby Power Service customers was set as part of the OEB's Decision and Order on the utility's 2006 Rate Application.[1] A copy of the original evidence can be found in Attachment VECC-108(A): Standby Billing.

[1] Hydro Ottawa Limited, *Application for Electricity Distribution Rates 2006*, EB-2005-0381/RP-2005-0020 (August 2, 2005).

10.6 Standby Charges

Hydro Ottawa is proposing to introduce a Standby Charge as part of its Application. The Standby Charge will apply to all customers with load displacement generators with a total combined nameplate rating greater than or equal to 500 kVA. The purpose of the Standby Charge is to recover the cost of providing reserved capacity to these customers and to eliminate cross-subsidization by other customers. Hydro Ottawa's distribution rates are designed based on the principle of continuous use. When customers displace load with generation, the expected revenue to recover capital, operating, maintenance and administration costs are not realized and the burden falls on other customers to subsidize those revenue shortfalls.

Due to the nature of Hydro Ottawa's distribution system and its embedded generators, site-specific Standby Charges are not practical. Generators are installed in very dense urban environments and determining what specific assets are related to each site is simply too difficult to assess. Hydro Ottawa is proposing to use class-specific charges instead.

Rate Structure

The Standby Charge is composed of a standby monthly service charge for administration and a standby distribution volumetric rate based on the Contract Backup Demand as determined by the methodology outlined in section 10.6.4.

Standby Monthly Service Charge – A monthly fixed charge applied to cover the incremental cost of monitoring, billing and administration related to providing standby facilities.

Standby Distribution Volumetric Rate – A rate per kW (or kVA; see section 10.8) of Billed Backup Demand. The Billed Backup Demand quantity will be equal to or less than the Contract Backup Demand depending on whether the reserved capacity was required during the billing period. The standby distribution volumetric rate would be equal to the class-specific distribution volumetric rate.

Customer Classification

The rate classification of customers with load displacement generators will be net of the connected generation. The 12-month average demand used to determine customer classifications will be the demand based on meter readings.

Contract Backup Demand

The Contract Backup Demand can be determined by using the full nameplate value of the generating plant or a lesser amount as agreed to by the customer and Hydro Ottawa. The customer can elect to contract for a lesser amount if it intends to shed load when the generation is not available. This will reduce the customer's monthly cost but may expose them to the Backup Overrun Adjustment if the contracted amount is exceeded. If a customer determines that no backup capacity is required, it must still sign a Standby Facilities Contract indicating that it has elected not to contract for backup capacity. Backup Overrun Adjustments will be applied if the customer is forced to use standby capacity for which it has not contracted. Hydro Ottawa reserves the right to impose a Contract Backup Demand if a customer fails to meet its obligations.

Determination of Billed Backup Demand

The Contract Backup Demand establishes a ceiling for Billed Backup Demand (excluding Backup Overrun Adjustments). The following three examples illustrate how the volumetric component of the Standby Charge is determined. The examples that follow assume that the regular distribution volumetric charges apply to the metered peak demand. The Standby Charge is intended to supplement demand shortfalls introduced by the generation.

Example 1 – Generation ON for entire period

In this case the Billed Backup Demand would be equal to the Contract Backup Demand. The Contract Backup Demand replaces demand that would have been captured by Hydro Ottawa's interval metering had the generation been off.

Example 2 – Generation OFF for entire period

In this case the Billed Backup Demand would be zero. The customer is billed based on the peak demand registered on Hydro Ottawa's interval meters.

Example 3 – Generation ON and OFF during period (No Backup Overruns)

In this example the Billed Backup Demand is:

Contract Demand – (Metered Peak generator OFF – Metered Peak generator ON)

This assumes that the difference between the generator OFF peak and the generator ON peak is less then the contracted amount; if not, the customer is subject to a Backup Overrun Adjustment.

Backup Overrun Adjustment

The Backup Overrun Adjustment is to ensure customers contract for the appropriate amount of standby capacity. Customers must meet contract requirements by shedding load if they have contracted for an amount less then the nameplate rating. The Backup Overrun Adjustment is calculated as follows:

(Generator OFF Peak – Generator ON Peak) – Contract Backup Demand

If the Contract Backup Demand is less than the difference between the two peaks, a charge will apply.

Backup Overrun Adjustments are determined by reviewing interval data prior to and immediately after a generator change-of-status. The instantaneous demand difference with the generator on and off is determinative of the standby capacity used and any overrun used. The Backup Overrun Adjustments never exceed the nameplate rating of the generating plant; consequently, the Backup

Overrun Adjustment only applies to customers that have contracted for Backup Demand less then the generator nameplate rating.

Contract Backup Demand is reviewed on a quarterly basis. If a customer has exceeded the Contract Backup Demand (Backup Overrun Adjustment) in any of the three preceding billing periods, the Contract Backup Demand will be increased to the highest monthly level of utilization that occurred in those three months.

The Backup Overrun Adjustment is assessed at the same rate as the Billed Backup Demand.

Standby Monthly Service Charge

The Standby Monthly Service Charge is intended to cover the cost to determine, bill and monitor Billed Backup Demands and Backup Overrun Adjustments. The charge is based on time and material as shown on the following schedule.

Specific Service Charges: Embedded Generation –Standby Monthly Service Charge

Specific Service Charge Description:		$95 Standby Monthly Service Charge			
Used For: Standby Monthly Service Charge					
		Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time	95.00	1.0		$95.00
A	Direct Labour (inside staff) Overtime				
B	Direct Labour (field staff) Straight Time				
O	Direct Labour (field staff) Overtime				
U	Other Labour (Specify)				
R	Payroll Burden %	Included			
	Total Labour Cost				$95.00
O	Small Vehicle Time				
T	Large Vehicle Time				
H	Other: Material				
E	Contract				
R	Other				
	Total Other				
Total Cost					$95.00
	Specific Service Charge Value Requested - Round to nearest $5				**$95.00**

- Reading Generator Meter Data and analyzing peaks
- Producing Shadow report
- Producing Annual Statistical report

Table 10.4 – Standby Monthly Service Charge

Parallel Generation Data Requirements

Customers will be required to provide generator operating and load information pertaining to parallel generation with nameplate ratings greater than or equal to 500 kVA. All new generators will be metered to allow comparison to Hydro Ottawa's supply point load profile for determining billing demands. For existing generators, the Billed Backup Demand will be determined from the customer's generator load data and operating logs.

INTERROGATORY RESPONSE - VECC-109

9.0 –VECC -109

EXHIBIT REFERENCE:

Exhibit 9, Tab 1, Schedule 3

SUBJECT AREA: Facilities Renewal Program

Table 5 – UPDATED FOR 2019 ACTUALS – Gain on Sale of Existing Properties

	2019
Merivale Facility and Land	$375,007
Albion Facility and Land	$18,259
Albion Parcel C Land	$1,758,595
Total to Dispose to Customers[42]	**$2,151,861**

a) Are the costs shown in the Table 5 net of transaction costs?

b) If yes please provide a description of the transaction costs.

RESPONSE:

a) Yes, the costs shown in Table 5 are net of (e.g. after) transaction costs.

b) Transaction costs include environmental clean up, legal fees, real estate fees, disposition consultations, and facility clean up costs. Table A below provides a summary of the transaction costs.

Table A – Summary of Transaction Costs for Sale of Facilities

Facility/Property	Transaction Costs
Merivale Facility and Land	$114,597
Albion Facility and Land	$943,281
Albion Parcel C Land	$66,347
Total Transaction Costs	**$1,124,225**