

## UPDATED LOAD FORECAST

### 1. INTRODUCTION

Hydro Ottawa engaged Itron to complete a 2021-2025 sales and energy forecast for the utility. Itron completed forecasts for total energy and demand sales by rate class, total number of customers and connections, and billing demand. The sale and energy forecast utilized actual data on sales, customer numbers and connections, and actual purchases through December 2019. Forecasts were provided both with and without the impact of future Conservation and Demand Management (“CDM”) targets.

A sales forecast model was used. For details regarding the forecast methodology, including CDM persistence and future targets, economic assumptions, and data sources, please see the following Attachments:

- UPDATED Attachment 3-1-1(A): OEB Appendix 2-IB - Load Forecast Analysis
- Attachment 3-1-1(B): OEB Appendix 2-I - Load Forecast CDM Adjustment Workform
- UPDATED Attachment 3-1-1(C): Hydro Ottawa Long-Term Electric Energy and Demand Forecast (produced by Itron)
- Attachment 3-1-1(D): Part 1 - Load Forecast Data - Customers
- Attachment 3-1-1(D): Part 2 - Load Forecast Data - kWh
- Attachment 3-1-1(D): Part 3 - Load Forecast Data - kW

Hydro Ottawa has completed UPDATED Attachment 3-1-1(A): Appendix 2-IB OEB - Load Forecast Analysis<sup>1</sup> and Attachment 3-1-1(B): OEB Appendix 2-I - Load Forecast CDM Adjustment Workform.

Hydro Ottawa has adjusted Itron’s load forecast to include Sentinel Lights and Standby Power, as these were not forecasted separately by Itron.

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<sup>1</sup> Hydro Ottawa has made adjustments to Appendix 2-IB to include rows for the 2021-2025 forecast and has adjusted the demand per customer calculation.

## 2. LOAD FORECAST

The updated version of Table 1 provides Hydro Ottawa's sales forecast by MWh for 2021-2025.

**Table 1 – AS ORIGINALLY SUBMITTED – 2021-2025 Energy Sales Forecast by Customer Class (MWh)<sup>2</sup>**

	2021	2022	2023	2024	2025
Residential	2,253,081	2,273,964	2,299,513	2,333,345	2,353,299
General Service < 50 kW	700,163	699,456	697,989	698,161	696,245
General Service 50 to 1,000 kW Non Interval	1,080,341	1,041,565	1,002,911	966,522	925,376
General Service 50 to 1,000 kW Interval	1,353,381	1,396,553	1,440,200	1,487,344	1,528,486
General Service 1,000 to 1,499 kW	385,754	386,993	388,279	390,553	391,592
General Service 1,500 to 4,999 kW	682,977	682,362	682,571	684,488	683,614
Large Use	574,292	572,889	572,033	572,834	570,390
Unmetered Scattered Load	13,602	13,130	12,663	12,195	11,728
Sentinel Lighting	47	47	47	47	47
Street Lighting	22,107	21,225	20,413	19,603	18,854
<b>TOTAL MWh SALES</b>	<b>7,065,745</b>	<b>7,088,184</b>	<b>7,116,619</b>	<b>7,165,092</b>	<b>7,179,631</b>

**Table 1 – UPDATED FOR 2019 ACTUALS – 2021-2025 Energy Sales Forecast by Customer Class (MWh)<sup>3</sup>**

	2021	2022	2023	2024	2025
Residential	2,252,937	2,273,821	2,299,366	2,333,198	2,353,149
General Service < 50 kW	699,871	699,134	697,636	697,774	695,837
General Service 50 to 1,000 kW Non Interval	1,080,526	1,041,853	1,003,315	967,024	926,028
General Service 50 to 1,000 kW Interval	1,351,427	1,394,295	1,437,626	1,484,411	1,525,261
General Service 1,000 to 1,499 kW	385,754	386,993	388,279	390,553	391,592
General Service 1,500 to 4,999 kW	682,919	682,301	682,505	684,409	683,532
Large Use	574,292	572,889	572,033	572,834	570,390
Unmetered Scattered Load	13,602	13,130	12,663	12,195	11,728
Sentinel Lighting	47	47	47	47	47
Street Lighting	22,107	21,225	20,413	19,603	18,854
<b>TOTAL MWh SALES</b>	<b>7,063,482</b>	<b>7,085,688</b>	<b>7,113,883</b>	<b>7,162,048</b>	<b>7,176,418</b>

<sup>2</sup> This forecast does not include the Dry Core Transformer Charge.

<sup>3</sup> This forecast does not include the Dry Core Transformer Charge.

1 The updated version of Table 2 below provides Hydro Ottawa's demand forecast by kW for  
2 2021-2025.

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4 **Table 2 – AS ORIGINALLY SUBMITTED – 2021-2025 Demand Sales Forecast by Customer**

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**Class (kW)**

	2021	2022	2023	2024	2025
General Service 50 to 1,000 kW Non Interval	2,784,778	2,699,506	2,614,514	2,534,500	2,444,024
General Service 50 to 1,000 kW Interval	3,177,890	3,262,709	3,348,459	3,441,080	3,521,915
General Service 1,000 to 1,499 kW	853,436	855,950	858,555	863,172	865,279
General Service 1,500 to 4,999 kW	1,518,349	1,517,223	1,517,607	1,521,105	1,519,514
Large Use	1,052,899	1,050,767	1,049,467	1,050,683	1,046,964
Standby Power	7,440	7,440	7,440	7,440	7,440
Sentinel Lighting	132	132	132	132	132
Street Lighting	61,588	58,863	56,618	54,373	52,530
<b>TOTAL KW DEMAND SALES</b>	<b>9,456,512</b>	<b>9,452,590</b>	<b>9,452,792</b>	<b>9,472,485</b>	<b>9,457,798</b>

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7 **Table 2 – UPDATED FOR 2019 ACTUALS – 2021-2025 Demand Sales Forecast by**

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**Customer Class (kW)**

	2021	2022	2023	2024	2025
General Service 50 to 1,000 kW Non Interval	2,786,967	2,702,337	2,617,997	2,538,583	2,448,864
General Service 50 to 1,000 kW Interval	3,174,724	3,259,157	3,344,504	3,436,652	3,517,111
General Service 1,000 to 1,499 kW	853,438	855,951	858,556	863,172	865,281
General Service 1,500 to 4,999 kW	1,517,165	1,516,028	1,516,400	1,519,896	1,518,291
Large Use	1,052,901	1,050,767	1,049,467	1,050,683	1,046,964
Standby Power	7,440	7,440	7,440	7,440	7,440
Sentinel Lighting	132	132	132	132	132
Street Lighting	61,590	58,864	56,618	54,374	52,530
<b>TOTAL KW DEMAND SALES</b>	<b>9,454,357</b>	<b>9,450,676</b>	<b>9,451,114</b>	<b>9,470,932</b>	<b>9,456,613</b>

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### 3. CUSTOMER AND CONNECTION FORECAST

Tables 3 and 4 below provide Hydro Ottawa's average number of customers and connections that are forecasted for the 2021-2025 period.

**Table 3 – 2021-2025 Average Number of Customers by Class**

	2021	2022	2023	2024	2025
Residential	316,346	319,386	322,306	325,150	327,975
General Service < 50 kW	25,391	25,554	25,704	25,846	25,987
General Service 50 to 1,000 kW Non Interval	2,004	1,930	1,856	1,782	1,707
General Service 50 to 1,000 kW Interval	1,043	1,082	1,120	1,158	1,196
General Service 1,000 to 1,499 kW	73	73	73	73	73
General Service 1,500 to 4,999 kW	68	68	68	68	68
Large Use	11	11	11	11	11
Standby Power	3	3	3	3	3
<b>TOTAL CUSTOMERS</b>	<b>344,939</b>	<b>348,107</b>	<b>351,141</b>	<b>354,091</b>	<b>357,020</b>

**Table 4 – 2021-2025 Average Number of Connections by Customer Class**

	2021	2022	2023	2024	2025
Unmetered Scattered Load	3,321	3,321	3,321	3,321	3,321
Sentinel Lighting	55	55	55	55	55
Street Lighting	62,806	63,725	64,645	65,564	66,484
<b>TOTAL CONNECTIONS</b>	<b>66,182</b>	<b>67,101</b>	<b>68,021</b>	<b>68,940</b>	<b>69,860</b>

### 4. TRANSFORMER OWNERSHIP CREDIT FORECAST

The updated version of Table 5 below provides Hydro Ottawa's forecast kW for 2021-2025 for the transformer ownership credit ("TOC"). As of November 1, 2025, the TOC will be discontinued for all customers. Please refer to UPDATED Exhibit 8-1-1: Fixed/Variable Proportion for more details.

**Table 5 – AS ORIGINALLY SUBMITTED – 2021-2025 Demand Sales Forecast (kW) for Transformer Ownership Credit**

	2021	2022	2023	2024	2025
General Service 50 to 1,000 kW Non Interval	309,783	309,743	309,824	310,548	310,124
General Service 50 to 1,000 kW Interval	100,914	100,901	100,927	101,163	101,025
General Service 1,000 to 1,499 kW	352,026	351,981	352,073	352,895	352,414
General Service 1,500 to 4,999 kW	882,411	882,299	882,529	884,591	883,383
Large Use	701,705	701,615	701,798	703,438	702,478
<b>TOTAL KW DEMAND SALES</b>	<b>2,346,838</b>	<b>2,346,539</b>	<b>2,347,151</b>	<b>2,352,635</b>	<b>2,349,424</b>

**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
<b>TOTAL KW DEMAND SALES</b>	<b>2,346,299</b>	<b>2,346,060</b>	<b>2,346,731</b>	<b>2,352,247</b>	<b>2,349,128</b>

For the 2021-2025 class level revenue forecast, please see the Revenue Requirement Workform ("RRWF") attachments listed below:

- **UPDATED** Attachment 6-1-1(A): OEB Workform - 2021 Revenue Requirement Workform
- **UPDATED** Attachment 6-1-1(B): OEB Workform - 2022 Revenue Requirement Workform
- **UPDATED** Attachment 6-1-1(C): OEB Workform - 2023 Revenue Requirement Workform

- 1 • **UPDATED** Attachment 6-1-1(D): OEB Workform - 2024 Revenue Requirement
- 2 Workform
- 3 • **UPDATED** Attachment 6-1-1(E): OEB Workform - 2025 Revenue Requirement Workform
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## 5. **CDM ADJUSTMENTS**

6 Tables 6 and 7 below summarize Hydro Ottawa's CDM adjustments to its load forecast. The  
7 CDM adjustments are comprised of assumptions related to the following:

- 9 • Projected CDM savings from projects that are subject to contractual agreements  
10 between the utility and customers, made on or before April 30, 2019;
- 11 • Estimated rate base savings, as outlined in Exhibit 4-1-6: Conservation and Demand  
12 Management; and
- 13 • Estimated impacts related to the continuation of CDM programs which are still being  
14 administered at the provincial level (i.e. by the Independent Electricity System Operator  
15 ["IESO"]).
- 16

17 Table 6 provides Hydro Ottawa's sales forecast CDM adjustments by MWh for 2021-2025.

1 **Table 6 – 2021-2025 Energy Sales CDM Adjustments by Customer Class (MWh)<sup>4</sup>**

	2021	2022	2023	2024	2025
Residential	8,478	9,135	9,219	9,300	9,379
General Service < 50 kW	16,151	19,798	24,180	28,566	31,935
General Service 50 to 1,000 kW Non Interval	20,319	23,573	26,304	28,816	30,851
General Service 50 to 1,000 kW Interval	25,653	31,796	37,983	44,596	51,222
General Service 1,000 to 1,499 kW	8,487	10,056	11,313	12,369	13,090
General Service 1,500 to 4,999 kW	48,038	53,795	58,785	63,772	68,370
Large Use	29,971	31,374	32,230	33,085	33,873
Unmetered Scattered Load	112	131	149	168	179
Sentinel Lighting	0	0	0	0	0
Street Lighting	5,308	6,194	7,006	7,816	8,565
<b>TOTAL MWh SALES</b>	<b>162,517</b>	<b>185,852</b>	<b>207,169</b>	<b>228,488</b>	<b>247,464</b>

2  
3 Table 7 below provides Hydro Ottawa's demand forecast CDM adjustments by kW for  
4 2021-2025.

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6 **Table 7 – 2021-2025 Demand Sales CDM Adjustments by Customer Class (kW)**

	2021	2022	2023	2024	2025
General Service > 50 to 1,499 kW	112,290	134,704	155,421	176,080	195,031
General Service 1,500 to 4,999 kW	87,899	98,431	107,562	116,692	125,101
Large Use	45,592	47,724	49,024	50,327	51,527
Standby Power	0	0	0	0	0
Sentinel Lighting	0	0	0	0	0
Street Lighting	14,272	17,025	19,270	21,515	23,358
<b>TOTAL KW DEMAND SALES</b>	<b>260,053</b>	<b>297,884</b>	<b>331,277</b>	<b>364,614</b>	<b>395,017</b>

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8 <sup>4</sup> This forecast does not include the Dry Core Transformer Charge.

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

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

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

**Distribution System (Total)**

	Calendar Year (for 2021 Cost of Service)		Consumption (kWh) (3)			
				Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2015		Actual	7,409,199,533	7,404,434,000	OEB-approved
Historical	2016		Actual	7,407,917,661	7,262,271,000	
Historical	2017		Actual	7,221,217,895	7,273,227,000	
Historical	2018		Actual	7,396,491,891	7,185,159,000	
Bridge Year	2019		Actual	7,268,791,267	7,216,529,000	
Bridge Year	2020		Forecast		7,129,018,000	
Test Year	2021		Forecast		7,063,482,000	
Test Year	2022		Forecast		7,085,688,000	
Test Year	2023		Forecast		7,113,883,000	
Test Year	2024		Forecast		7,162,048,000	
Test Year	2025		Forecast		7,176,418,000	

Variance Analysis	Year	Year-over-year		Versus OEB- approved
	2015			
	2016	0.0%	-1.9%	
	2017	-2.5%	0.2%	
	2018	2.4%	-1.2%	
	2019	-1.7%	0.4%	
	2020	-100.0%	-1.2%	
	2021		-0.9%	
	2022		0.3%	
	2023		0.4%	
	2024		0.7%	
	2025		0.2%	
	Geometric Mean	-0.6%	-0.9%	



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

1 Customer Class: Residential Is the customer class billed on consumption (kWh) or demand (kW or kVA)?

kW

	Calendar Year (for 2021 Cost of Service)	Customers			Consumption (kWh) (3)			Consumption (kWh) per Customer		
					Actual (Weather actual)	Weather- normalized	Weather- normalized	Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2015	Actual	293,884	OEB-approved	Actual	2,242,517,759	2,241,280,000	Actual	7,631	7,626
Historical	2016	Actual	298,001		Actual	2,260,335,626	2,203,863,000	Actual	7,585	7,395
Historical	2017	Actual	301,839		Actual	2,188,889,238	2,232,966,000	Actual	7,252	7,398
Historical	2018	Actual	305,390		Actual	2,318,157,312	2,227,858,000	Actual	7,591	7,295
Historical	2019	Actual	309,165		Actual	2,263,214,648	2,256,981,000	Actual	7,320	7,300
Bridge Year	2020	Forecast	313,134		Forecast		2,254,424,000	Forecast	0	7,200
Test Year	2021	Forecast	316,346		Forecast		2,252,937,000	Forecast	0	7,122
Test Year	2022	Forecast	319,386		Forecast		2,273,821,000	Forecast	0	7,119
Test Year	2023	Forecast	322,306		Forecast		2,299,366,000	Forecast	0	7,134
Test Year	2024	Forecast	325,150		Forecast		2,333,198,000	Forecast	0	7,176
Test Year	2025	Forecast	327,975		Forecast		2,353,149,000	Forecast	0	7,175

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved
Historical	2015			2015			2015		
Historical	2016	1.4%		2016	0.8% -1.7%		2016	-0.6% -3.0%	
Historical	2017	1.3%		2017	-3.2% 1.3%		2017	-4.4% 0.0%	
Historical	2018	1.2%		2018	5.9% -0.2%		2018	4.7% -1.4%	
Historical	2019	1.2%		2019	-2.4% 1.3%		2019	-3.6% 0.1%	
Bridge Year	2020	1.3%		2020	-100.0% -0.1%		2020	-100.0% -1.4%	
Test Year	2021	1.0%		2021	-0.1%		2021	-1.1%	
Test Year	2022	1.0%		2022	0.9%		2022	0.0%	
Test Year	2023	0.9%		2023	1.1%		2023	0.2%	
Test Year	2024	0.9%		2024	1.5%		2024	0.6%	
Test Year	2025	4.7%		2025	0.9%		2025	0.0%	
	Geometric Mean	1.2%		Geometric Mean	0.3% 0.5%		Geometric Mean	-1.4% -0.7%	

	Calendar Year (for 2021 Cost of Service)	Revenues			Demand (kW)			Demand (kW) per Customer		
					Actual (Weather actual)	Weather- normalized	Weather- normalized	Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2015	Actual	\$ 86,662,173	OEB-approved	Actual			Actual	0	0
Historical	2016	Actual	\$ 90,945,757		Actual			Actual	0	0
Historical	2017	Actual	\$ 92,970,029		Actual			Actual	0	0
Historical	2018	Actual	\$ 99,559,087		Actual			Actual	0	0
Historical	2019	Actual	\$ 104,856,328		Actual			Actual	0	0
Bridge Year	2020	Forecast	\$ 104,307,875		Forecast			Forecast	0	0
Test Year	2021	Forecast	\$ 116,124,290		Forecast			Forecast	0	0
Test Year	2022	Forecast	\$ 124,445,561		Forecast			Forecast	0	0
Test Year	2023	Forecast	\$ 131,655,555		Forecast			Forecast	0	0
Test Year	2024	Forecast	\$ 136,680,054		Forecast			Forecast	0	0
Test Year	2025	Forecast	\$ 140,307,705		Forecast			Forecast	0	0

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved
Historical	2015			2015			2015		
Historical	2016	4.9%		2016			2016		
Historical	2017	2.2%		2017			2017		
Historical	2018	7.1%		2018			2018		
Historical	2019	5.3%		2019			2019		
Bridge Year	2020	14.7%		2020			2020		
Test Year	2021	11.3%		2021			2021		
Test Year	2022	7.2%		2022			2022		
Test Year	2024	9.8%		2024			2024		
Test Year	2025	2.7%		2025			2025		
	Geometric Mean	5.5%		Geometric Mean			Geometric Mean		

2 Customer Class: GS < 50 kW Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2021 Cost of Service)	Customers				Consumption (kWh) (3)				Consumption (kWh) per Customer			
						Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized	
Historical	2015	Actual	24,392	OEB-approved		Actual	723,754,871	722,461,000	OEB-approved		Actual	29,672	29,619
Historical	2016	Actual	24,623			Actual	733,311,565	724,983,000			Actual	29,782	29,443
Historical	2017	Actual	24,786			Actual	712,368,650	719,547,000			Actual	28,741	29,030
Historical	2018	Actual	24,926			Actual	727,990,863	712,045,000			Actual	29,206	28,566
Historical	2019	Actual	25,030			Actual	724,761,278	720,536,000			Actual	28,956	28,787
Bridge Year	2020	Forecast	25,200			Forecast		707,564,000			Forecast	0	28,078
Test Year	2021	Forecast	25,391			Forecast		699,871,000			Forecast	0	27,564
Test Year	2022	Forecast	25,554			Forecast		699,134,000			Forecast	0	27,359
Test Year	2023	Forecast	25,704			Forecast		697,636,000			Forecast	0	27,141
Test Year	2024	Forecast	25,846			Forecast		697,774,000			Forecast	0	26,997
Test Year	2025	Forecast	25,987			Forecast		695,837,000			Forecast	0	26,776

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved
Historical	2015			2015			2015		
Historical	2016	0.9%		2016	1.3% 0.3%		2016	0.4% -0.6%	
Historical	2017	0.7%		2017	-2.9% -0.7%		2017	-3.5% -1.4%	
Historical	2018	0.6%		2018	2.2% -1.0%		2018	1.6% -1.6%	
Historical	2019	0.4%		2019	-0.4% 1.2%		2019	-0.9% 0.8%	
Bridge Year	2020	0.7%		2020	-100.0% -1.8%		2020	-100.0% -2.5%	
Test Year	2021	0.8%		2021	-1.1%		2021	-1.8%	
Test Year	2022	0.6%		2022	-0.1%		2022	-0.7%	
Test Year	2023	0.6%		2023	-0.2%		2023	-0.8%	
Test Year	2024	3.3%		2024	-3.2%		2024	-0.5%	
Test Year	2025	0.5%		2025	-0.3%		2025	-0.8%	
	Geometric Mean	0.7%			Geometric Mean		-0.4%		

	Calendar Year (for 2021 Cost of Service)	Revenues				Demand (kWh)				Demand (kWh) per Customer			
						Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized	
Historical	2015	Actual	\$ 20,147,319	OEB-approved		Actual		OEB-approved		Actual	0	0	
Historical	2016	Actual	\$ 21,249,335			Actual				Actual	0	0	
Historical	2017	Actual	\$ 21,132,353			Actual				Actual	0	0	
Historical	2018	Actual	\$ 22,199,693			Actual				Actual	0	0	
Historical	2019	Actual	\$ 25,095,042			Actual				Actual	0	0	
Bridge Year	2020	Forecast	\$ 23,280,095			Forecast				Forecast	0	0	
Test Year	2021	Forecast	\$ 24,966,258			Forecast				Forecast	0	0	
Test Year	2022	Forecast	\$ 26,680,774			Forecast				Forecast	0	0	
Test Year	2023	Forecast	\$ 28,258,530			Forecast				Forecast	0	0	
Test Year	2024	Forecast	\$ 29,333,599			Forecast				Forecast	0	0	
Test Year	2025	Forecast	\$ 30,076,336			Forecast				Forecast	0	0	

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved
Historical	2015			2015			2015		
Historical	2016	5.5%		2016			2016		
Historical	2017	-0.6%		2017			2017		
Historical	2018	5.1%		2018			2018		
Historical	2019	13.0%		2019			2019		
Bridge Year	2020	-7.2%		2020			2020		
Test Year	2021	7.2%		2021			2021		
Test Year	2022	6.9%		2022			2022		
Test Year	2023	5.9%		2023			2023		
Test Year	2024	3.8%		2024			2024		
Test Year	2025	2.5%		2025			2025		
	Geometric Mean	4.6%			Geometric Mean				

3 Customer Class: GS > 50 to 1,499 kW Is the customer class billed on consumption (kWh) or demand (kW or kVA)?

kW

	Calendar Year (for 2021 Cost of Service)	Customers				Consumption (kWh) (3)				Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2015	Actual	3,326	OEB-approved		Actual	2,949,262,003	2,945,598,000	OEB-approved	Actual	886,729	885,628	OEB-approved
Historical	2016	Actual	3,207			Actual	2,958,900,805	2,890,976,000		Actual	922,638	901,458	
Historical	2017	Actual	3,215			Actual	2,907,121,740	2,899,051,000		Actual	904,237	901,727	
Historical	2018	Actual	3,224			Actual	2,971,283,949	2,882,252,000		Actual	921,614	893,999	
Historical	2019	Actual	3,181			Actual	2,913,690,983	2,870,031,000		Actual	915,967	902,242	
Bridge Year	2020	Forecast	3,146			Forecast		2,838,242,000		Forecast	0	902,175	
Test Year	2021	Forecast	3,120			Forecast		2,817,707,000		Forecast	0	903,111	
Test Year	2022	Forecast	3,085			Forecast		2,823,141,000		Forecast	0	915,119	
Test Year	2023	Forecast	3,049			Forecast		2,829,220,000		Forecast	0	927,917	
Test Year	2024	Forecast	3,013			Forecast		2,841,988,000		Forecast	0	943,242	
Test Year	2025	Forecast	2,976			Forecast		2,842,881,000		Forecast	0	955,269	

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved
Historical	2015	Actual		2015			2015		
Historical	2016	Actual	-3.6%	2016	0.3%	-1.9%	2016	4.0%	1.8%
Historical	2017	Actual	0.2%	2017	-1.7%	0.3%	2017	-2.0%	0.0%
Historical	2018	Actual	0.3%	2018	2.2%	-0.6%	2018	1.9%	-0.9%
Historical	2019	Actual	-1.3%	2019	-1.9%	-0.4%	2019	-0.6%	0.9%
Bridge Year	2020	Forecast	-1.1%	2020	-100.0%	-1.1%	2020	-100.0%	0.0%
Test Year	2021	Forecast	-0.8%	2021		-0.7%	2021		0.1%
Test Year	2022	Forecast	-1.1%	2022		0.2%	2022		1.3%
Test Year	2023	Forecast	-1.2%	2023		0.2%	2023		1.4%
Test Year	2024	Forecast	-1.2%	2024		0.5%	2024		1.7%
Test Year	2025	Forecast	-1.2%	2025		0.0%	2025		1.3%
	Geometric Mean		-1.2%	Geometric Mean	-100.0%	-0.4%	Geometric Mean	-100.0%	0.8%

	Calendar Year (for 2021 Cost of Service)	Revenues				Demand (kW)				Demand (kW) per Customer			
							Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2015	Actual	\$ 35,899,655	OEB-approved		Actual	7,203,146	7,172,939	OEB-approved	Actual	2,166	2,157	OEB-approved
Historical	2016	Actual	\$ 36,179,929			Actual	7,075,314	7,020,354		Actual	2,206	2,189	
Historical	2017	Actual	\$ 37,626,286			Actual	6,985,551	7,028,949		Actual	2,173	2,186	
Historical	2018	Actual	\$ 39,429,376			Actual	7,171,762	6,973,449		Actual	2,224	2,163	
Historical	2019	Actual	\$ 38,803,030			Actual	6,890,080	6,937,927		Actual	2,166	2,181	
Bridge Year	2020	Forecast	\$ 40,904,860			Forecast		6,866,524		Forecast	0	2,183	
Test Year	2021	Forecast	\$ 44,681,903			Forecast		6,815,129		Forecast	0	2,184	
Test Year	2022	Forecast	\$ 47,766,023			Forecast		6,817,445		Forecast	0	2,210	
Test Year	2023	Forecast	\$ 50,544,505			Forecast		6,821,057		Forecast	0	2,237	
Test Year	2024	Forecast	\$ 52,481,058			Forecast		6,838,407		Forecast	0	2,270	
Test Year	2025	Forecast	\$ 53,870,770			Forecast		6,831,256		Forecast	0	2,295	

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved
Historical	2015			2015			2015		
Historical	2016		0.8%	2016	-1.8%	-2.1%	2016	1.9%	1.5%
Historical	2017		4.0%	2017	-1.3%	0.1%	2017	-1.5%	-0.1%
Historical	2018		4.8%	2018	2.7%	-0.8%	2018	2.4%	-1.1%
Historical	2019		-1.6%	2019	-3.9%	-0.5%	2019	-2.6%	0.8%
Bridge Year	2020		5.4%	2020	-100.0%	-1.0%	2020	-100.0%	0.1%
Test Year	2021		9.2%	2021		-0.7%	2021		0.1%
Test Year	2022		6.9%	2022		0.0%	2022		1.2%
Test Year	2023		5.8%	2023		0.1%	2023		1.2%
Test Year	2024		3.8%	2024		0.3%	2024		1.5%
Test Year	2025		2.6%	2025		-0.1%	2025		1.1%
	Geometric Mean		4.6%	Geometric Mean	-100.0%	-0.5%	Geometric Mean	-100.0%	0.7%

4 Customer Class: GS > 1,500 to 4,999 kW Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2021 Cost of Service)	Customers				Consumption (kWh) (3)					Consumption (kWh) per Customer				
						Actual (Weather actual)	Weather- normalized		Weather- normalized			Actual (Weather actual)	Weather- normalized		Weather- normalized
Historical	2015	Actual	79	OEB-approved	Actual	867,663,053	868,325,000	OEB-approved		Actual	10,983,077	10,991,456	OEB-approved		
Historical	2016	Actual	72		Actual	805,583,761	797,370,000		Actual	11,188,663	11,074,583				
Historical	2017	Actual	74		Actual	753,196,270	759,004,000		Actual	10,178,328	10,256,811				
Historical	2018	Actual	68		Actual	723,849,223	712,925,000		Actual	10,644,842	10,484,191				
Historical	2019	Actual	67		Actual	723,713,557	724,066,000		Actual	10,801,695	10,806,955				
Bridge Year	2020	Forecast	68		Forecast		701,743,000			Forecast	0	10,319,750			
Test Year	2021	Forecast	68		Forecast		682,919,000			Forecast	0	10,042,926			
Test Year	2022	Forecast	68		Forecast		682,301,000			Forecast	0	10,033,838			
Test Year	2023	Forecast	68		Forecast		682,505,000			Forecast	0	10,036,838			
Test Year	2024	Forecast	68		Forecast		684,409,000			Forecast	0	10,064,838			
Test Year	2025	Forecast	68		Forecast		683,532,000			Forecast	0	10,051,941			

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved		
Historical	2015			2015			2015				
Historical	2016	-8.9%		2016	-7.2%		-8.2%	2016		1.9%	0.8%
Historical	2017	2.8%		2017	-6.5%		-4.8%	2017		-9.0%	-7.4%
Historical	2018	-8.1%		2018	-3.9%		-6.1%	2018		4.6%	2.2%
Historical	2019	-1.5%		2019	0.0%		1.6%	2019		1.5%	3.1%
Bridge Year	2020	1.5%		2020	-100.0%		-3.1%	2020		-100.0%	-4.5%
Test Year	2021	-8.1%		2021			-2.7%	2021			2.2%
Test Year	2022	-1.5%		2022			1.6%	2022			3.1%
Test Year	2023	1.5%		2023			-5.5%	2023			-6.9%
Test Year	2024	0.0%		2024			-2.6%	2024			-2.6%
Test Year	2025	0.0%		2025			-0.1%	2025			-0.1%
	Geometric Mean	-1.7%			Geometric Mean		-5.9%	-2.6%		Geometric Mean	-0.6%

	Calendar Year (for 2021 Cost of Service)	Revenues				Demand (kW)					Demand (kW) per Customer				
						Actual (Weather actual)	Weather- normalized		Weather- normalized			Actual (Weather actual)	Weather- normalized		Weather- normalized
Historical	2015	Actual	\$ 9,361,880	OEB-approved	Actual	1,848,869	1,885,572	OEB-approved		Actual	23,403	23,868	OEB-approved		
Historical	2016	Actual	\$ 9,521,453		Actual	1,726,981	1,731,827		Actual	23,986	24,053				
Historical	2017	Actual	\$ 9,754,449		Actual	1,649,388	1,650,012		Actual	22,289	22,297				
Historical	2018	Actual	\$ 9,406,664		Actual	1,580,852	1,548,930		Actual	23,248	22,778				
Historical	2019	Actual	\$ 10,535,253		Actual	1,604,681	1,573,758		Actual	23,950	23,489				
Bridge Year	2020	Forecast	\$ 12,744,060		Forecast		1,551,714			Forecast	0	22,819			
Test Year	2021	Forecast	\$ 10,829,246		Forecast		1,517,165			Forecast	0	22,311			
Test Year	2022	Forecast	\$ 11,572,133		Forecast		1,516,028			Forecast	0	22,295			
Test Year	2023	Forecast	\$ 12,245,667		Forecast		1,516,400			Forecast	0	22,300			
Test Year	2024	Forecast	\$ 12,714,911		Forecast		1,519,896			Forecast	0	22,351			
Test Year	2025	Forecast	\$ 13,051,553		Forecast		1,518,291			Forecast	0	22,328			

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved		
Historical	2015			2015			2015				
Historical	2016	1.7%		2016	-6.6%		-8.2%	2016		2.5%	0.8%
Historical	2017	2.4%		2017	-4.5%		-4.7%	2017		-7.1%	-7.3%
Historical	2018	-3.6%		2018	-4.2%		-6.1%	2018		4.3%	2.2%
Historical	2019	12.0%		2019	1.5%		1.6%	2019		3.0%	3.1%
Bridge Year	2020	21.0%		2020	-100.0%		-1.4%	2020		-100.0%	-2.9%
Test Year	2021	-15.0%		2021			-2.2%	2021			-2.2%
Test Year	2022	6.9%		2022			-0.1%	2022			-0.1%
Test Year	2023	5.8%		2023			0.0%	2023			0.0%
Test Year	2024	3.8%		2024			0.2%	2024			0.2%
Test Year	2025	2.6%		2025			-0.1%	2025			-0.1%
	Geometric Mean	3.8%			Geometric Mean		-100.0%	-2.4%		Geometric Mean	-100.0%

5 Customer Class: Large Use Is the customer class billed on consumption (kWh) or demand (kW or kVA)?

kW

	Calendar Year (for 2021 Cost of Service)	Customers				Consumption (kWh) (3)					Consumption (kWh) per Customer			
						Actual (Weather actual)	Weather- normalized	Weather- normalized			Actual (Weather actual)	Weather- normalized	Weather- normalized	
Historical	2015	Actual	10	OEB-approved	Actual	564,803,671	565,577,000	OEB-approved	Actual	56,480,367	56,557,700	OEB-approved		
Historical	2016	Actual	11		Actual	588,872,536	584,167,000		Actual	53,533,867	53,106,091			
Historical	2017	Actual	12		Actual	606,156,950	609,177,000		Actual	50,513,079	50,764,750			
Historical	2018	Actual	13		Actual	608,577,999	603,448,000		Actual	46,813,692	46,419,077			
Historical	2019	Actual	11		Actual	602,082,783	603,590,000		Actual	54,734,798	54,871,818			
Bridge Year	2020	Forecast	11		Forecast		588,828,000		Forecast	0	53,529,818			
Test Year	2021	Forecast	11		Forecast		574,292,000		Forecast	0	52,208,364			
Test Year	2022	Forecast	11		Forecast		572,889,000		Forecast	0	52,080,818			
Test Year	2023	Forecast	11		Forecast		572,033,000		Forecast	0	52,003,000			
Test Year	2024	Forecast	11		Forecast		572,834,000		Forecast	0	52,075,818			
Test Year	2025	Forecast	11		Forecast		570,390,000		Forecast	0	51,853,636			

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved		
Historical	2015			2015			2015				
Historical	2016	10.0%		2016	4.3%		3.3%	2016		-5.2%	-6.1%
Historical	2017	9.1%		2017	2.9%		4.3%	2017		-5.6%	-4.4%
Historical	2018	8.3%		2018	0.4%		-0.9%	2018		-7.3%	-8.6%
Historical	2019	-15.4%		2019	-1.1%		0.0%	2019		16.9%	18.2%
Bridge Year	2020	0.0%		2020	-100.0%		-2.4%	2020		-100.0%	-2.4%
Test Year	2021	0.0%		2021			-2.5%	2021			-2.5%
Test Year	2022	0.0%		2022			-0.2%	2022			-0.2%
Test Year	2023	0.0%		2023			-0.1%	2023			-0.1%
Test Year	2024	0.0%		2024			0.1%	2024			0.1%
Test Year	2025	0.0%	2025		-0.4%	2025		-0.4%			
	Geometric Mean	1.1%		Geometric Mean	-100.0%	0.1%	Geometric Mean	-100.0%	-1.0%		

	Calendar Year (for 2021 Cost of Service)	Revenues				Demand (kW)					Demand (kW) per Customer			
						Actual (Weather actual)	Weather- normalized	Weather- normalized			Actual (Weather actual)	Weather- normalized	Weather- normalized	
Historical	2015	Actual	\$ 4,948,419	OEB-approved	Actual	1,045,761	1,026,493	OEB-approved	Actual	104,576	102,649	OEB-approved		
Historical	2016	Actual	\$ 5,152,898		Actual	1,071,626	1,061,398		Actual	97,421	96,491			
Historical	2017	Actual	\$ 6,052,658		Actual	1,100,755	1,105,747		Actual	91,730	92,146			
Historical	2018	Actual	\$ 6,218,737		Actual	1,106,783	1,095,710		Actual	85,137	84,285			
Historical	2019	Actual	\$ 6,737,691		Actual	1,064,513	1,096,064		Actual	96,774	99,642			
Bridge Year	2020	Forecast	\$ 6,729,311		Forecast		1,075,011		Forecast	0	97,728			
Test Year	2021	Forecast	\$ 7,289,429		Forecast		1,052,901		Forecast	0	95,718			
Test Year	2022	Forecast	\$ 7,790,002		Forecast		1,050,767		Forecast	0	95,524			
Test Year	2023	Forecast	\$ 8,243,395		Forecast		1,049,467		Forecast	0	95,406			
Test Year	2024	Forecast	\$ 8,559,248		Forecast		1,050,683		Forecast	0	95,517			
Test Year	2025	Forecast	\$ 8,785,857		Forecast		1,046,964		Forecast	0	95,179			

Variance Analysis	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved	Year	Year-over-year	Test Year Versus OEB- approved		
Historical	2015			2015			2015				
Historical	2016	4.1%		2016	2.5%		3.4%	2016		-6.8%	-6.0%
Historical	2017	17.5%		2017	2.7%		4.2%	2017		-5.8%	-4.5%
Historical	2018	2.7%		2018	0.5%		-0.9%	2018		-7.2%	-8.5%
Historical	2019	8.3%		2019	-3.8%		0.0%	2019		13.7%	18.2%
Bridge Year	2020	-0.1%		2020	-100.0%		-1.9%	2020		-100.0%	-1.9%
Test Year	2021	8.3%		2021			-2.1%	2021			-2.1%
Test Year	2022	6.9%		2022			-0.2%	2022			-0.2%
Test Year	2023	5.8%		2023			-0.1%	2023			-0.1%
Test Year	2024	3.8%		2024			0.1%	2024			0.1%
Test Year	2025	2.6%	2025		-0.4%	2025		-0.4%			
	Geometric Mean	6.6%		Geometric Mean	-100.0%	0.2%	Geometric Mean	-100.0%	-0.8%		

6 Customer Class: Street Lighting Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2021 Cost of Service)	Customers				Consumption (kWh) (3)				Consumption (kWh) per Customer						
							Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized			
Historical	2015	Actual	56,682	OEB-approved		Actual	45,151,658	45,150,000		Actual	797	797				
Historical	2016	Actual	58,588			Actual	45,206,290	45,206,000		Actual	772	772				
Historical	2017	Actual	58,470			Actual	38,203,632	38,204,000		Actual	653	653				
Historical	2018	Actual	59,286			Actual	31,723,370	31,723,000		Actual	535	535				
Historical	2019	Actual	60,538			Actual	26,730,515	26,728,000		Actual	442	442				
Bridge Year	2020	Forecast	61,886			Forecast		24,064,000		Forecast	0	389				
Test Year	2021	Forecast	62,806			Forecast		22,107,000		Forecast	0	352				
Test Year	2022	Forecast	63,725			Forecast		21,225,000		Forecast	0	333				
Test Year	2023	Forecast	64,645			Forecast		20,413,000		Forecast	0	316				
Test Year	2024	Forecast	65,564			Forecast		19,603,000		Forecast	0	299				
Test Year	2025	Forecast	66,484			Forecast		18,854,000		Forecast	0	284				
Variance Analysis																
	Year	Year-over-year			Test Year Versus OEB- approved	Year	Year-over-year			Test Year Versus OEB- approved	Year	Year-over-year			Test Year Versus OEB- approved	
Historical	2015					2015					2015					
Historical	2016	3.4%				2016	0.1%	0.1%	2016		-3.1%	-3.1%				
Historical	2017	-0.2%				2017	-15.5%	-15.5%	2017		-15.3%	-15.3%				
Historical	2018	1.4%				2018	-17.0%	-17.0%	2018		-18.1%	-18.1%				
Historical	2019	2.1%				2019	-15.7%	-15.7%	2019		-17.5%	-17.5%				
Bridge Year	2020	2.2%				2020	-100.0%	-10.0%	2020		-100.0%	-11.9%				
Test Year	2021	1.5%				2021		-8.1%	2021			-9.5%				
Test Year	2022	1.5%				2022		-4.0%	2022			-5.4%				
Test Year	2023	1.4%				2023		-3.8%	2023			-5.2%				
Test Year	2024	1.4%				2024		-4.0%	2024			-5.3%				
Test Year	2025	1.4%				2025		-3.8%	2025			-5.2%				
	Geometric Mean	1.8%			Geometric Mean	-100.0%	-9.2%	Geometric Mean	-100.0%	-10.8%						

	Calendar Year (for 2021 Cost of Service)	Revenues				Demand (kW)				Demand (kW) per Customer						
							Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized			
Historical	2015	Actual	\$ 856,864	OEB-approved		Actual	125,349	125,350		Actual	2	2				
Historical	2016	Actual	\$ 1,211,096			Actual	125,463	125,465		Actual	2	2				
Historical	2017	Actual	\$ 1,150,869			Actual	106,296	106,296		Actual	2	2				
Historical	2018	Actual	\$ 1,121,289			Actual	81,768	88,707		Actual	1	1				
Historical	2019	Actual	\$ 1,277,158			Actual	80,895	74,394		Actual	1	1				
Bridge Year	2020	Forecast	\$ 1,387,140			Forecast		67,033		Forecast	0	1				
Test Year	2021	Forecast	\$ 1,126,911			Forecast		61,590		Forecast	0	1				
Test Year	2022	Forecast	\$ 1,205,328			Forecast		58,864		Forecast	0	1				
Test Year	2023	Forecast	\$ 1,274,794			Forecast		56,618		Forecast	0	1				
Test Year	2024	Forecast	\$ 1,322,985			Forecast		54,374		Forecast	0	1				
Test Year	2025	Forecast	\$ 1,357,443			Forecast		52,530		Forecast	0	1				
Variance Analysis																
	Year	Year-over-year			Test Year Versus OEB- approved	Year	Year-over-year			Test Year Versus OEB- approved	Year	Year-over-year			Test Year Versus OEB- approved	
Historical	2015					2015					2015					
Historical	2016	41.3%				2016	0.1%	0.1%	2016		-3.2%	-3.2%				
Historical	2017	-5.0%				2017	-15.3%	-15.3%	2017		-15.1%	-15.1%				
Historical	2018	-2.6%				2018	-23.1%	-16.5%	2018		-24.1%	-17.7%				
Historical	2019	13.9%				2019	-1.1%	-16.1%	2019		-3.1%	-17.9%				
Bridge Year	2020	8.6%				2020	-100.0%	-9.9%	2020		-100.0%	-11.9%				
Test Year	2021	-18.8%				2021		-8.1%	2021			-9.5%				
Test Year	2022	7.0%				2022		-4.4%	2022			-5.8%				
Test Year	2023	5.8%				2023		-3.8%	2023			-5.2%				
Test Year	2024	3.8%				2024		-4.0%	2024			-5.3%				
Test Year	2025	2.6%				2025		-3.4%	2025			-4.7%				
	Geometric Mean	5.2%			Geometric Mean	-100.0%	-9.2%	Geometric Mean	-100.0%	-1						

7 Customer Class: Sentinel Lights Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2021 Cost of Service)	Customers				Consumption (kWh) (3)				Consumption (kWh) per Customer					
							Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized		
Historical	2015	Actual	55	OEB-approved		Actual	48,804	47,000	OEB-approved		Actual	887	855		
Historical	2016	Actual	62			Actual	48,064	47,000			Actual	775	758		
Historical	2017	Actual	58			Actual	51,051	47,000			Actual	880	810		
Historical	2018	Actual	57			Actual	48,433	47,000			Actual	850	825		
Historical	2019	Actual	55			Actual	47,813	47,000			Actual	869	855		
Bridge Year	2020	Forecast	55			Forecast		47,000			Forecast	0	855		
Test Year	2021	Forecast	55			Forecast		47,000			Forecast	0	855		
Test Year	2022	Forecast	55			Forecast		47,000			Forecast	0	855		
Test Year	2023	Forecast	55			Forecast		47,000			Forecast	0	855		
Test Year	2024	Forecast	55			Forecast		47,000			Forecast	0	855		
Test Year	2025	Forecast	55			Forecast		47,000			Forecast	0	855		
Variance Analysis															
Historical	Year	Year-over-year			Test Year Versus OEB- approved	Year	Year-over-year			Test Year Versus OEB- approved	Year	Year-over-year			Test Year Versus OEB- approved
	2015					2015					2015				
	2016	12.7%				2016	-1.5%	0.0%	2016		-12.6%	-11.3%			
	2017	-6.5%				2017	6.2%	0.0%	2017		13.5%	6.9%			
	2018	-1.7%				2018	-5.1%	0.0%	2018		-3.5%	1.8%			
	2019	-3.5%				2019	-1.3%	0.0%	2019		2.3%	3.6%			
	2020	0.0%				2020	-100.0%	0.0%	2020		-100.0%	0.0%			
	2021	-11.3%				2021		0.0%	2021			0.0%			
	2022	0.0%				2022		0.0%	2022			0.0%			
	2023	0.0%				2023		0.0%	2023			0.0%			
	2024	0.0%				2024		0.0%	2024			0.0%			
	2025	0.0%				2025		0.0%	2025			0.0%			
		Geometric Mean	0.0%			Geometric Mean	-100.0%	0.0%	Geometric Mean		-100.0%	0.0%			
	Calendar Year (for 2021 Cost of Service)	Revenues				Demand (kW)				Demand (kW) per Customer					
							Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized		
Historical	2015	Actual	\$ 3,036	OEB-approved		Actual	136	132	OEB-approved		Actual	2	2		
Historical	2016	Actual	\$ 3,505			Actual	134	132			Actual	2	2		
Historical	2017	Actual	\$ 3,912			Actual	142	132			Actual	2	2		
Historical	2018	Actual	\$ 4,106			Actual	135	132			Actual	2	2		
Historical	2019	Actual	\$ 4,187			Actual	133	132			Actual	2	2		
Bridge Year	2020	Forecast	\$ 4,691			Forecast		132			Forecast	0	2		
Test Year	2021	Forecast	\$ 5,002			Forecast		132			Forecast	0	2		
Test Year	2022	Forecast	\$ 5,934			Forecast		132			Forecast	0	2		
Test Year	2023	Forecast	\$ 6,843			Forecast		132			Forecast	0	2		
Test Year	2024	Forecast	\$ 7,691			Forecast		132			Forecast	0	2		
Test Year	2025	Forecast	\$ 8,500			Forecast		132			Forecast	0	2		
Variance Analysis															
Historical	Year	Year-over-year			Test Year Versus OEB- approved	Year	Year-over-year			Test Year Versus OEB- approved	Year	Year-over-year			Test Year Versus OEB- approved
	2015					2015					2015				
	2016	15.5%				2016	-1.5%	0.0%	2016		-12.6%	-11.3%			
	2017	11.6%				2017	6.0%	0.0%	2017		13.3%	6.9%			
	2018	5.0%				2018	-4.9%	0.0%	2018		-3.3%	1.8%			
	2019	2.0%				2019	-1.5%	0.0%	2019		2.1%	3.6%			
	2020	12.0%				2020	-100.0%	0.0%	2020		-100.0%	0.0%			
	2021	6.6%				2021		0.0%	2021			0.0%			
	2022	18.6%				2022		0.0%	2022			0.0%			
	2023	15.3%				2023		0.0%	2023			0.0%			
	2024	12.4%				2024		0.0%	2024			0.0%			
	2025	10.5%				2025		0.0%	2025			0.0%			
		Geometric Mean	12.1%			Geometric Mean	-100.0%	0.0%	Geometric Mean		-100.0%	0.0%			

8 Customer Class: Unmetered Scattered Load

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

kWh

	Calendar Year (for 2021 Cost of Service)	Customers				Consumption (kWh) (3)				Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2015	Actual	3,398			Actual	15,997,714	15,996,000	OEB-approved	Actual	4,708	4,707	OEB-approved
Historical	2016	Actual	3,416			Actual	15,659,015	15,659,000		Actual	4,584	4,584	
Historical	2017	Actual	3,443			Actual	15,230,364	15,231,000		Actual	4,424	4,424	
Historical	2018	Actual	3,440			Actual	14,860,742	14,861,000		Actual	4,320	4,320	
Historical	2019	Actual	3,382			Actual	14,549,690	14,550,000		Actual	4,302	4,302	
Bridge Year	2020	Forecast	3,321			Forecast		14,106,000		Forecast	0	4,248	
Test Year	2021	Forecast	3,321			Forecast		13,602,000		Forecast	0	4,096	
Test Year	2022	Forecast	3,321			Forecast		13,130,000		Forecast	0	3,954	
Test Year	2023	Forecast	3,321			Forecast		12,663,000		Forecast	0	3,813	
Test Year	2024	Forecast	3,321			Forecast		12,195,000		Forecast	0	3,672	
Test Year	2025	Forecast	3,321			Forecast		11,728,000		Forecast	0	3,531	

Variance Analysis				Test Year Versus OEB- approved				Test Year Versus OEB- approved				Test Year Versus OEB- approved
	Year	Year-over-year			Year	Year-over-year			Year	Year-over-year		
Historical	2015				2015				2015			
Historical	2016	0.5%			2016	-2.1%	-2.1%		2016	-2.6%	-2.6%	
Historical	2017	0.8%			2017	-2.7%	-2.7%		2017	-3.5%	-3.5%	
Historical	2018	-0.1%			2018	-2.4%	-2.4%		2018	-2.3%	-2.3%	
Historical	2019	-1.7%			2019	-2.1%	-2.1%		2019	-0.4%	-0.4%	
Bridge Year	2020	-1.8%			2020	-100.0%	-3.1%		2020	-100.0%	-1.3%	
Test Year	2021	-2.8%			2021		-3.6%		2021		-10.7%	
Test Year	2022	0.0%			2022		-3.5%		2022		-3.5%	
Test Year	2023	0.0%			2023		-3.6%		2023		-3.6%	
Test Year	2024	0.0%			2024		-3.7%		2024		-3.7%	
Test Year	2025	0.0%			2025		-3.8%		2025		-3.8%	
	Geometric Mean	-0.3%			Geometric Mean	-100.0%	-3.4%		Geometric Mean	-100.0%	-3.1%	

	Calendar Year (for 2021 Cost of Service)	Revenues				Demand (kW)				Demand (kW) per Customer			
							Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2015	Actual	\$ 521,845	OEB-approved		Actual			OEB-approved	Actual	0	0	OEB-approved
Historical	2016	Actual	\$ 534,169			Actual				Actual	0	0	
Historical	2017	Actual	\$ 529,459			Actual				Actual	0	0	
Historical	2018	Actual	\$ 376,075			Actual				Actual	0	0	
Historical	2019	Actual	\$ 557,692			Actual				Actual	0	0	
Bridge Year	2020	Forecast	\$ 631,316			Forecast				Forecast	0	0	
Test Year	2021	Forecast	\$ 580,904			Forecast				Forecast	0	0	
Test Year	2022	Forecast	\$ 622,437			Forecast				Forecast	0	0	
Test Year	2023	Forecast	\$ 658,038			Forecast				Forecast	0	0	
Test Year	2024	Forecast	\$ 682,993			Forecast				Forecast	0	0	
Test Year	2025	Forecast	\$ 701,468			Forecast				Forecast	0	0	

Variance Analysis				Test Year Versus OEB- approved				Test Year Versus OEB- approved				
	Year	Year-over-year			Year	Year-over-year			Year	Year-over-year		
Historical	2015				2015				2015			
Historical	2016	2.4%			2016				2016			
Historical	2017	-0.9%			2017				2017			
Historical	2018	-29.0%			2018				2018			
Historical	2019	48.3%			2019				2019			
Bridge Year	2020	13.2%			2020				2020			
Test Year	2021	-8.0%			2021				2021			
Test Year	2022	7.1%			2022				2022			
Test Year	2023	5.7%			2023				2023			
Test Year	2024	3.8%			2024				2024			
Test Year	2025	2.7%			2025				2025			
	Geometric Mean	3.3%			Geometric Mean				Geometric Mean			



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

	Calendar Year (for 2021 Cost of Service)	Customers			Consumption (kWh) (3)				Consumption (kWh) per Customer			
					Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized	
Historical	2015	Actual	OEB-approved		Actual	OEB-approved			Actual	OEB-approved		
Historical	2016	Actual			Actual				Actual			
Historical	2017	Actual			Actual				Actual			
Historical	2018	Actual			Actual				Actual			
Historical	2019	Forecast			Forecast				Forecast			
Bridge Year	2020	Forecast			Forecast				Forecast			
Test Year	2021	Forecast			Forecast				Forecast			
Test Year	2022	Forecast			Forecast				Forecast			
Test Year	2023	Forecast			Forecast				Forecast			
Test Year	2024	Forecast			Forecast				Forecast			
Test Year	2025	Forecast			Forecast				Forecast			

Variance Analysis	Year	Year-over-year		Test Year Versus OEB- approved	Year	Year-over-year		Test Year Versus OEB- approved	Year	Year-over-year		Test Year Versus OEB- approved
Historical	2015				2015				2015			
Historical	2016				2016				2016			
Historical	2017				2017				2017			
Historical	2018				2018				2018			
Bridge Year	2019				2019				2019			
Bridge Year	2020				2020				2020			
Test Year	2021				2021				2021			
Test Year	2022				2022				2022			
Test Year	2023				2023				2023			
Test Year	2024				2024				2024			
Test Year	2025				2025				2025			
	Geometric Mean				Geometric Mean				Geometric Mean			

	Calendar Year (for 2021 Cost of Service)	Revenues			Demand (kW)				Demand (kW) per Customer			
					Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized	
Historical	2015	Actual			Actual	OEB-approved			Actual	OEB-approved		
Historical	2016	Actual			Actual				Actual			
Historical	2017	Actual			Actual				Actual			
Historical	2018	Actual			Actual				Actual			
Bridge Year	2019	Forecast			Forecast				Forecast			
Bridge Year	2020	Forecast			Forecast				Forecast			
Test Year	2021	Forecast			Forecast				Forecast			
Test Year	2022	Forecast			Forecast				Forecast			
Test Year	2023	Forecast			Forecast				Forecast			
Test Year	2024	Forecast			Forecast				Forecast			
Test Year	2025	Forecast			Forecast				Forecast			

Variance Analysis	Year	Year-over-year		Test Year Versus OEB- approved	Year	Year-over-year		Test Year Versus OEB- approved	Year	Year-over-year		Test Year Versus OEB- approved
Historical	2015				2015				2015			
Historical	2016				2016				2016			
Historical	2017				2017				2017			
Historical	2018				2018				2018			
Bridge Year	2019				2019				2019			
Bridge Year	2020				2020				2020			
Test Year	2021				2021				2021			
Test Year	2022				2022				2022			
Test Year	2023				2023				2023			
Test Year	2024				2024				2024			
Test Year	2025				2025				2025			
	Geometric Mean				Geometric Mean				Geometric Mean			

10 Customer Class:

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

	Calendar Year (for 2021 Cost of Service)	Customers			Consumption (kWh) (3)				Consumption (kWh) per Customer			
						Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2015	Actual	OEB-approved		Actual		OEB-approved		Actual		OEB-approved	
Historical	2016	Actual			Actual				Actual			
Historical	2017	Actual			Actual				Actual			
Historical	2018	Actual			Actual				Actual			
Bridge Year	2019	Forecast			Forecast				Forecast			
Bridge Year	2020	Forecast			Forecast				Forecast			
Test Year	2021	Forecast			Forecast				Forecast			
Test Year	2022	Forecast			Forecast				Forecast			
Test Year	2023	Forecast			Forecast				Forecast			
Test Year	2024	Forecast			Forecast				Forecast			
Test Year	2025	Forecast			Forecast				Forecast			

Variance Analysis				Test Year Versus OEB- approved				Test Year Versus OEB- approved				Test Year Versus OEB- approved
	Year	Year-over-year			Year	Year-over-year			Year	Year-over-year		
Historical	2015				2015				2015			
Historical	2016				2016				2016			
Historical	2017				2017				2017			
Historical	2018				2018				2018			
Bridge Year	2019				2019				2019			
Bridge Year	2020				2020				2020			
Test Year	2021				2021				2021			
Test Year	2022				2022				2022			
Test Year	2023				2023				2023			
Test Year	2024				2024				2024			
Test Year	2025				2025				2025			
	Geometric Mean				Geometric Mean				Geometric Mean			

	Calendar Year (for 2021 Cost of Service)	Revenues			Demand (kW)				Demand (kW) per Customer			
						Actual (Weather actual)	Weather- normalized	Weather- normalized		Actual (Weather actual)	Weather- normalized	Weather- normalized
Historical	2015	Actual	OEB-approved		Actual		OEB-approved		Actual		OEB-approved	
Historical	2016	Actual			Actual				Actual			
Historical	2017	Actual			Actual				Actual			
Historical	2018	Actual			Actual				Actual			
Bridge Year	2019	Forecast			Forecast				Forecast			
Bridge Year	2020	Forecast			Forecast				Forecast			
Test Year	2021	Forecast			Forecast				Forecast			
Test Year	2022	Forecast			Forecast				Forecast			
Test Year	2023	Forecast			Forecast				Forecast			
Test Year	2024	Forecast			Forecast				Forecast			
Test Year	2025	Forecast			Forecast				Forecast			

Variance Analysis				Test Year Versus OEB- approved				Test Year Versus OEB- approved				Test Year Versus OEB- approved
	Year	Year-over-year			Year	Year-over-year			Year	Year-over-year		
Historical	2015				2015				2015			
Historical	2016				2016				2016			
Historical	2017				2017				2017			
Historical	2018				2018				2018			
Bridge Year	2019				2019				2019			
Bridge Year	2020				2020				2020			
Test Year	2021				2021				2021			
Test Year	2022				2022				2022			
Test Year	2023				2023				2023			
Test Year	2024				2024				2024			
Test Year	2025				2025				2025			
	Geometric Mean				Geometric Mean				Geometric Mean			

Note: If there are more than ten (10) customer classes, please contact OEB Staff to add tables for additional customer classes.

## Appendix 2-I Load Forecast CDM Adjustment Work Form

Appendix 2-I was initially developed to help determine what would be the amount of CDM savings needed in each year to cumulatively achieve the four year 2011-2014 CDM target. This then determined the amount of kWh (and with translation, kW of demand) savings that were converted into dollar balances for the LRAMVA, and also to determine the related adjustment to the load forecast to account for OPA-reported savings. Beginning in the 2015 year, it was adjusted because the persistence of 2011-2014 CDM programs will be an adjustment to the load forecast in addition to the estimated savings for the first year (2015) for the new 2015-2020 CDM plan. This appendix has been updated for 2020 rate applications to acknowledge that in accordance with the Minister of Energy's March 20, 2019 Directive to the IESO, the Conservation First Framework (CFF) is no longer in effect. As distributors are no longer working towards the former 2015-2020 CDM targets, for 2019 and 2020 activity only CDM projects that are subject to a contractual agreement entered into between the distributor and a customer by April 30, 2019 under a former CFF program should be included in the proposed CDM manual adjustment to the load forecast. Distributors should provide relevant documentation to support the manual adjustments for 2019 and 2020 CDM projects, including the corresponding CFF program, project timelines and projected savings. For any savings from new projects that begin on or after May 1, 2019 that are under the IESO's interim framework (May 1, 2019 to December 31, 2020), distributors should not include these savings as part of the 2020 CDM manual adjustment.

### 2019-2020 CDM Activities

For the first year of the new 2015-2020 CDM plan, for simplicity it was assumed that each year's program will achieve an equal amount of new CDM savings. This resulted in each year's program being about 1/6 (or 16.67%) of the cumulative 2015-2020 CDM target for kWh savings. A distributor could have proposed an alternative approach but would have been expected to document in its application why it believes that its proposal is more reasonable.

For 2020 rate applications, distributors should ensure that the sum of the results for the 2015 to 2018 program years is consistent with the results provided by the IESO. For 2019 and 2020 program years, the projected CDM savings should not match the distributor's CDM Plan or its 2015-2020 CDM targets. Rather, for 2019 and 2020 CDM activity, distributors should only include the projected CDM savings from projects that are subject to contractual agreements between the distributor and customer made on or before April 30, 2019 under the former CFF.

Former CFF 6 Year (2015-2020) kWh Target*							
394,586,000							
2015	2016	2017	2018	2019	2020	Total	
%							
2015 CDM Programs					16.07%		19.71%
2016 CDM Programs					18.58%		22.80%
2017 CDM Programs					27.46%		27.46%
2018 CDM Programs					14.19%		14.19%
2019 CDM Programs					11.85%		11.85%
2020 CDM Programs					26.66%		26.66%
Total in Year						114.82%	122.67%
kWh							
2015 CDM Programs					77,765,005.00		77,765,005.00
2016 CDM Programs					89,950,886.00		89,950,886.00
2017 CDM Programs					108,371,102.00		108,371,102.00
2018 CDM Programs					55,983,898.00		55,983,898.00
2019 CDM Programs					46,758,492.00		46,758,492.00
2020 CDM Programs					105,210,396.00		105,210,396.00
Total in Year						484,039,779.00	394,586,000.00
						Inputs do no match 2015-20 CDM target	

\*This total will not equal the distributor's former CFF CDM target. Rather, for 2019 and 2020, the distributor should only include the projected savings from projects that are subject to contractual agreements made between the LDC and a customer on or before April 30, 2019 under the former CFF.

Note: The default formulae in the above table assume that the 2015-2020 kWh CDM target is achieved through persistence of CDM savings to the end of 2020. The distributor should enter measured CDM savings for 2015, 2016, 2017 and 2018, and the persistence of 2015, 2016, 2017 and 2018 programs for 2018-2020 in rows 34, 35, 36 and 37. Distributors should rely on the Participant and Cost monthly reports provided by the IESO for 2018 CDM savings which can be entered into row 37. The distributor should include only those projected CDM savings in 2019 and 2020 from projects that it has contractual obligations with a customer on or before April 30, 2019 under the former CFF.

### Determination of 2020 Load Forecast Adjustment

The OEB determined that the "net" number should be used in its Decision and Order with respect to Centre Wellington Hydro Ltd.'s 2013 Cost of Service rates (EB-2012-0113). This approach has also been used in Settlement Agreements accepted by the OEB in other 2013 and 2014 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-1 defaults to the adjustment being done on a "net" basis consistent with OEB policy and practice.

From each of the 2006-2010 CDM Final Report, and the 2011 to 2017 CDM Final Reports, issued by the OPA/IESO for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2018 into cells C57 to C63 and D57 to D63. The model will calculate the cumulative savings for all programs from 2006 to 2016 and determine the "net" to "gross" factor "g".

Net-to-Gross Conversion				
Is CDM adjustment being done on a "net" or "gross" basis?				net
Persistence of Historical CDM programs to 2015	"Gross" kWh	"Net" kWh	Difference kWh	"Net-to-Gross" Conversion Factor ('g')
2006-2010 CDM programs			0	
2011 CDM program			0	
2012 CDM program			0	
2013 CDM program			0	
2014 CDM program			0	
2015 CDM program			0	
2016 CDM program			0	
2017 CDM program			0	
2018 CDM program*			0	
<b>2006 to 2017 OPA CDM programs: Persistence to 2020.</b>	0	0	0	0.00%

\*For 2018 CDM programs distributors should rely on the results made available by the IESO in the Participant and Cost monthly reports

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

These factors do not mean that CDM programs are excluded, but the assumption that impacts of previous year CDM programs are already implicitly reflected in the actual data for historical years that are used to derive the load forecast prior to any manual CDM adjustment for the 2020 test year.

### Weight Factor for Inclusion in CDM Adjustment to 2020 Load Forecast

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

\* For 2018 CDM programs distributors should rely on the results made available by the IESO in the Participant and Cost monthly reports

\*\* For 2019 and 2020 CDM program activity, the distributor should include only those projected CDM savings from projects that it has contractual obligations with a customer under the former CFF.

### 2015-2020 LRAMVA and 2020 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2020 load forecast is made. There is a different but related threshold amount that is used for the 2020 LRAMVA amount for Account 1568.

The amount used for the CDM threshold of the LRAMVA is the kWh that will be used to determine the base amount for the LRAMVA balance for 2020. This allows for a comparison between projected CDM savings and actual CDM savings.

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

The Manual Adjustment for the 2020 Load Forecast is the amount manually subtracted from the system-wide load forecast (either based on a purchased or billed basis) derived from the base forecast from historical data. If the distributor has developed their load forecast on a system purchased basis, then the manual adjustment should be on a system purchased basis, including the adjustment for losses. If the load forecast has been developed on a billed basis, either on a system basis or on a class-specific basis, the manual adjustment should be on a billed basis, excluding losses.

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

	2015	2016	2017	2018	2019	2020	Total for 2020
<b>Amount used for CDM threshold for LRAMVA (2020)</b>	77,765,005.00	89,950,886.00	108,371,102.00	55,983,898.00	46,758,492.00	105,210,396.00	<b>484,039,779.00</b>
<b>Manual Adjustment for 2020 Load Forecast (billed basis)</b>	-	-	-	27,991,949.00	46,758,492.00	52,605,198.00	127,355,639.00
<b>Manual Adjustment for 2020 LDC-only CDM programs (billed basis)</b>							
<b>Total Manual Forecast to Load Forecast</b>	-	-	-	27,991,949.00	46,758,492.00	52,605,198.00	<b>127,355,639.00</b>
<b>Proposed Loss Factor (TLF)</b>	3.35%	Format: X.XX%					
<b>Manual Adjustment for 2020 Load Forecast (system purchased basis)</b>	-	-	-	28,929,679.29	48,324,901.48	54,367,472.13	<b>131,622,052.91</b>

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)). The Weight factor is also used to calculate the impact of each year's program on the CDM adjustment to the 2020 load forecast.



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# 2019 Long-Term Electric Energy and Demand Forecast

## Hydro Ottawa

*Submitted to:*

Hydro Ottawa  
Ottawa, Ontario

*Submitted by:*

Itron, Inc.  
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March 2020

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# 1 Overview

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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.

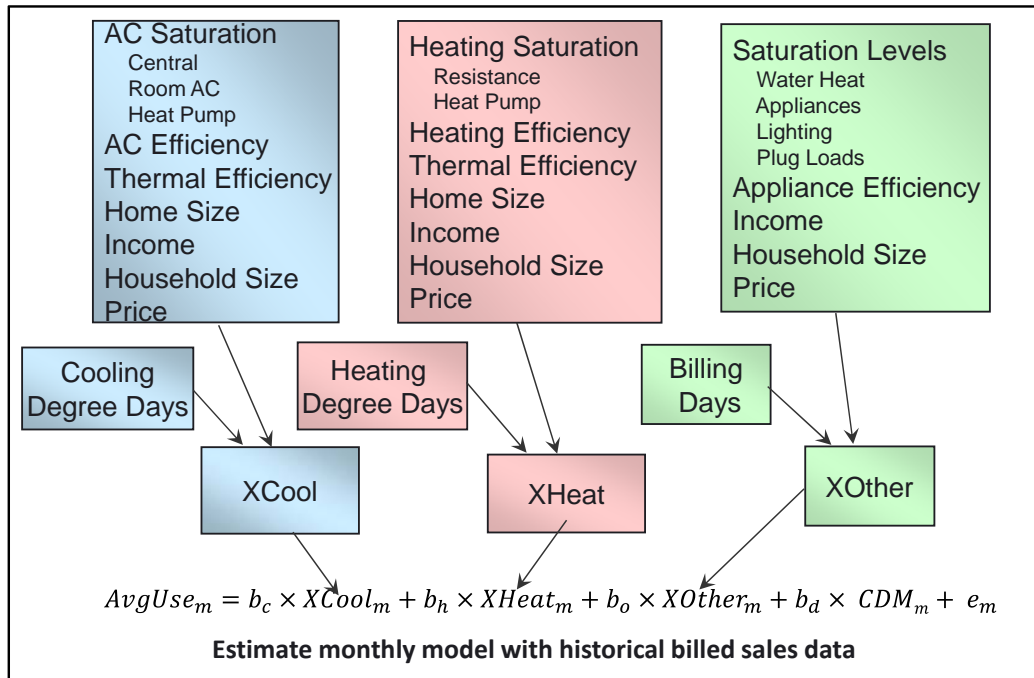
Hydro Ottawa serves approximately 311,500 residential customers and 28,300 nonresidential customers. Total 2019 sales equaled 7,241 GWh with a system peak of 1,398 MW. Residential customer class accounts for approximately 31% of system sales, small commercial 10% of sales (less than 50 kW), medium commercial 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 150-1000kW	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		System Purchases		Peak Demand	
	(MWh)	chg	(MWh)	chg	(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.

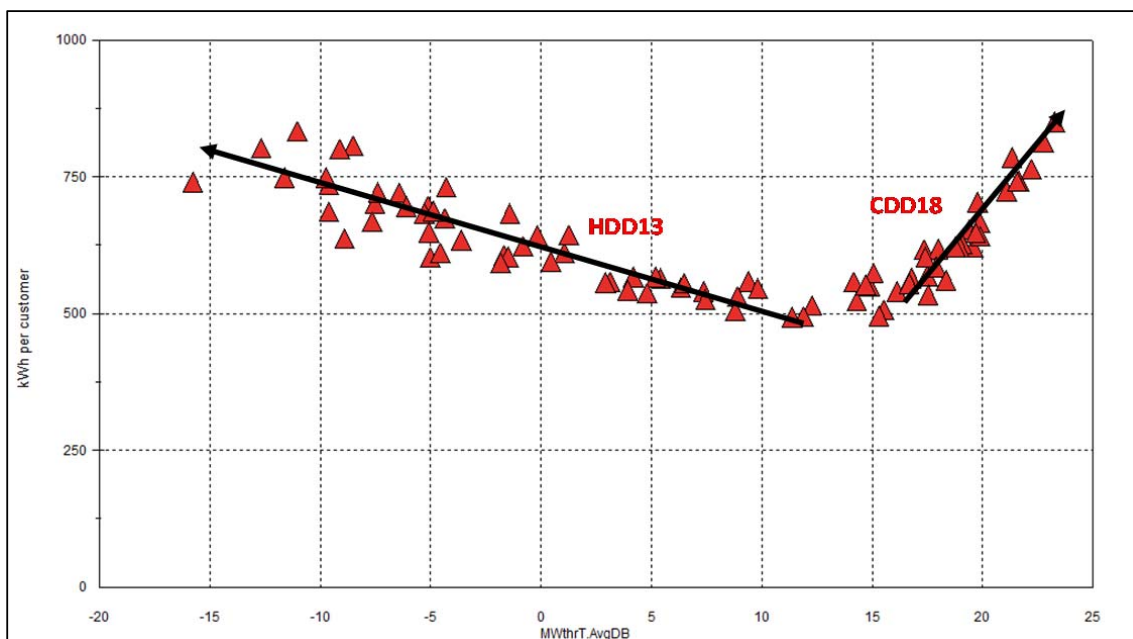
System peak demand forecast is based on reported monthly peaks from January 2013 to December 2019. While demand data is available prior to 2013, as this year's is a total "bottom-up" forecast driven by rate class forecast, there is no need for demand data prior to this point. System purchases are not 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**



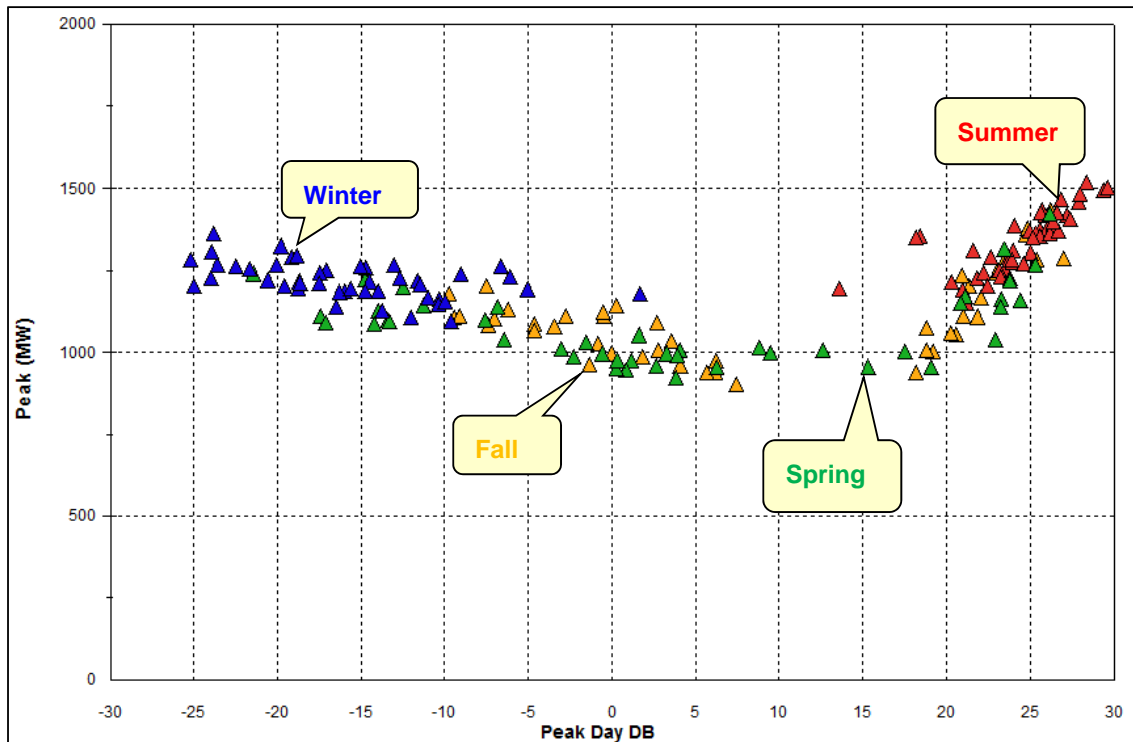
Normal monthly degree-days are calculated as an average of monthly degree-days over the past twenty years – 1999 through 2018.

### 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

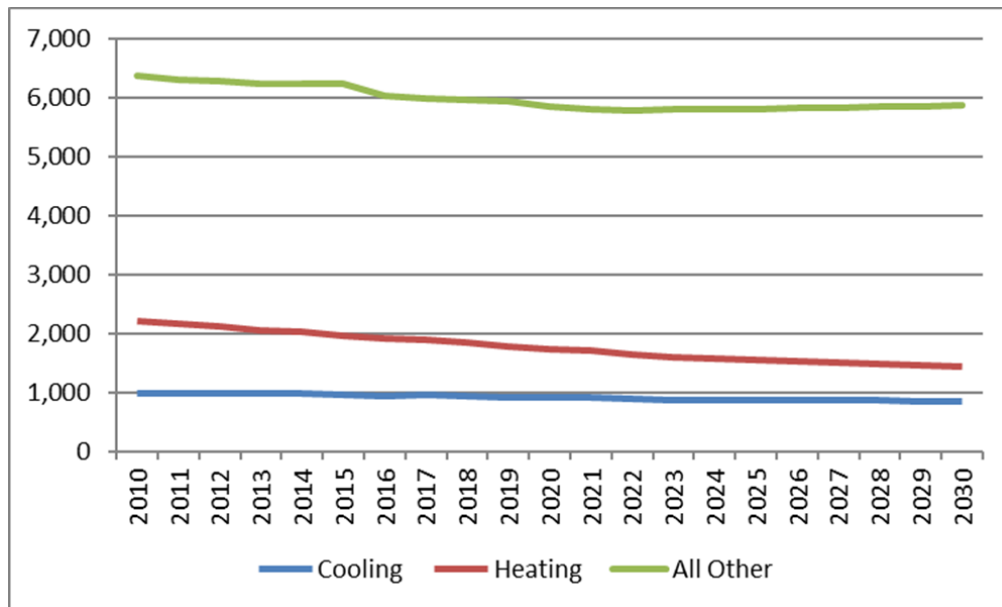
End-use intensities are calculated from end-use saturation estimates (the share of homes that own a specific appliance) and measure of equipment efficiency. As saturation increases, energy intensity increases. As efficiency improves end-use intensity decreases. Declining customer average use is largely attributable to efficiency gains that have been stronger than 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).

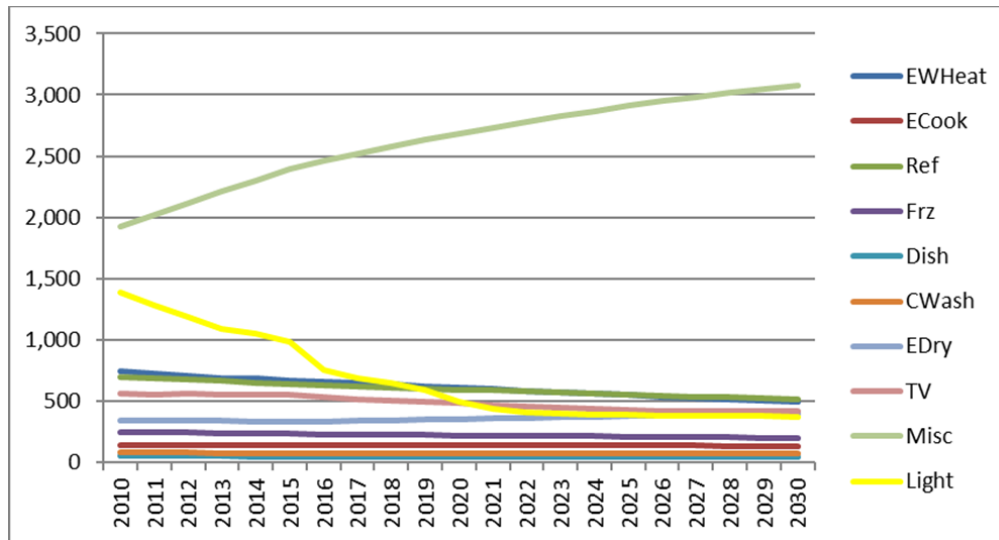
EIA develops end-use forecasts for nine census division. The end-use intensity forecasts are based on the Mid-Atlantic Census Division which includes New York. Intensities are modified to reflect Ontario end-use saturation trends; historical and forecasted end-use saturations are calibrated to reported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

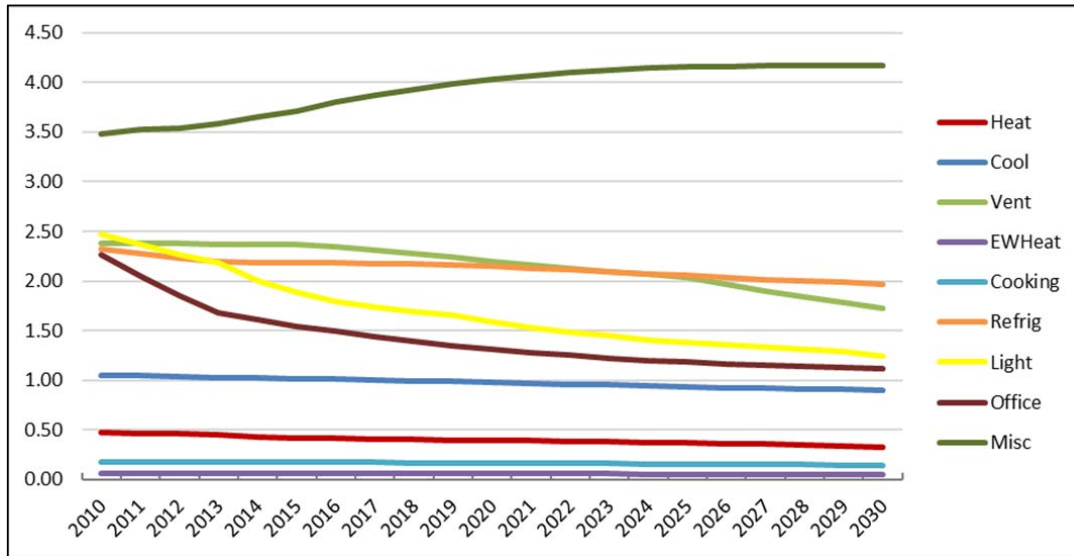


End-use intensities are generally declining as efficiency is increasing faster than appliance ownership. Most end-uses intensities change slowly over time as appliances are replaced with more efficient options. The exceptions are lighting and miscellaneous which are also the two largest end-uses. Lighting 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

#### 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:

$$XHeat_m = HDDIdx_m \times IncIdx_m^{0.15} \times HeatIntensity_a$$

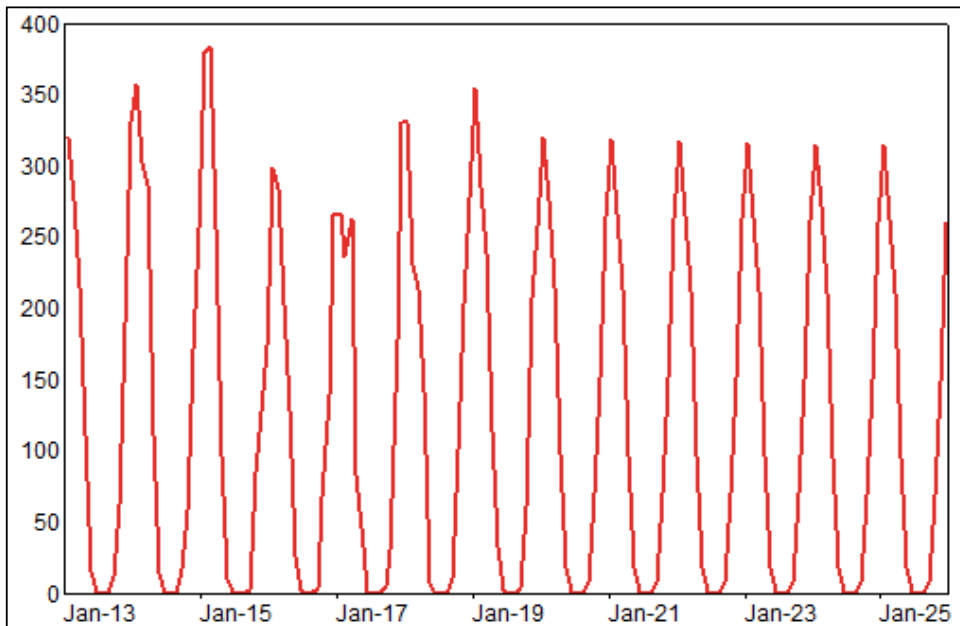
Where

- $HDDIDX_m$  = 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:

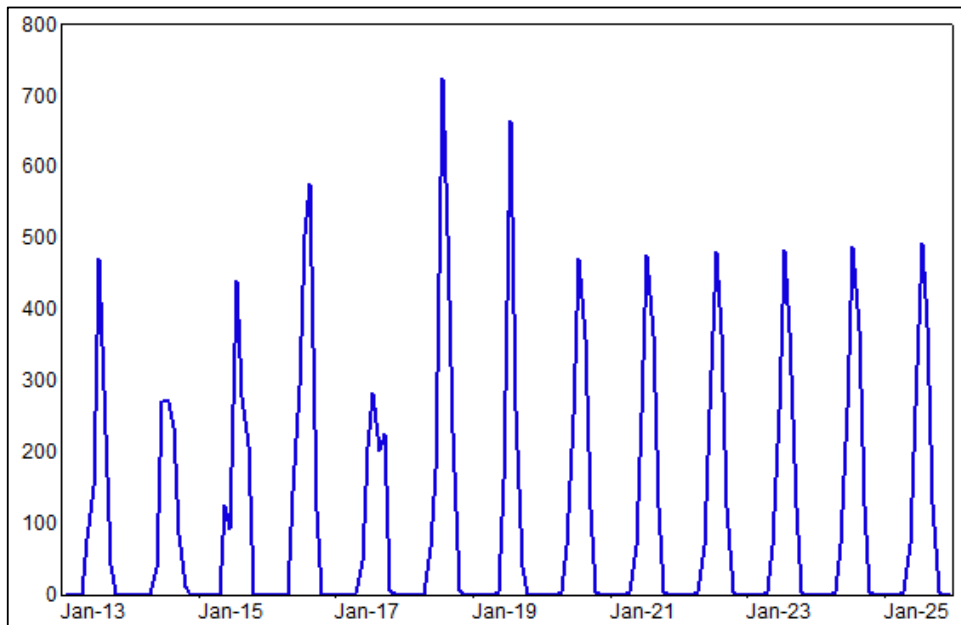
$$XCool_m = CDDIdx_m \times IncIdx_m^{0.15} \times CoolIntensity_a$$

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**



$X_{Other}$  captures non-weather sensitive end-use

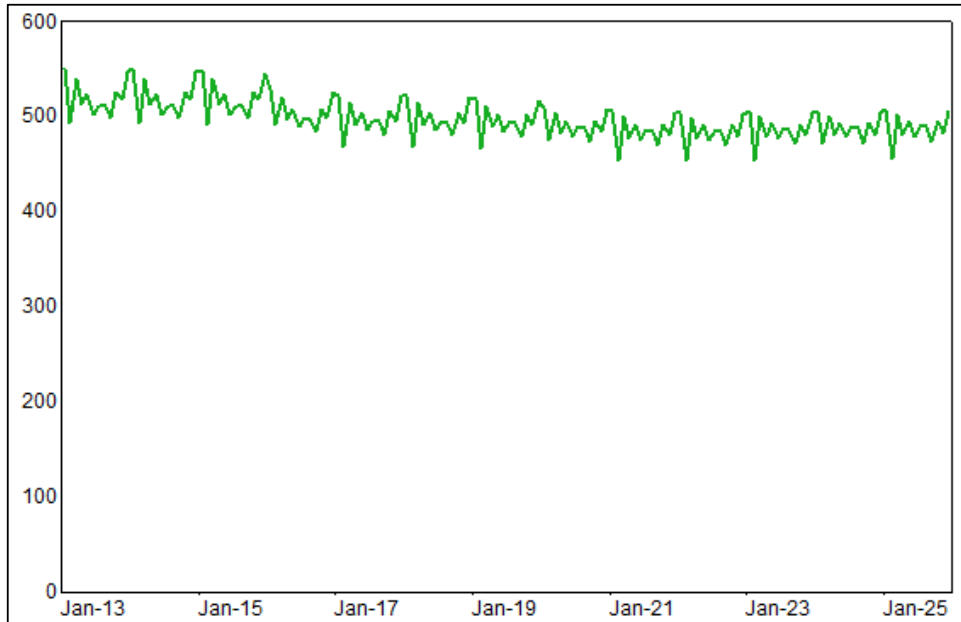
$$X_{Other_m} = DaysIdx_m \times IncIdx_m^{0.15} \times OtherIntensity_a \times MonthlyMultiplier_m$$

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)
- $MoMultiplier_m$  = monthly end-use usage fraction (fraction of annual usage)

Figure 9 shows the calculated  $X_{Other}$  variable.

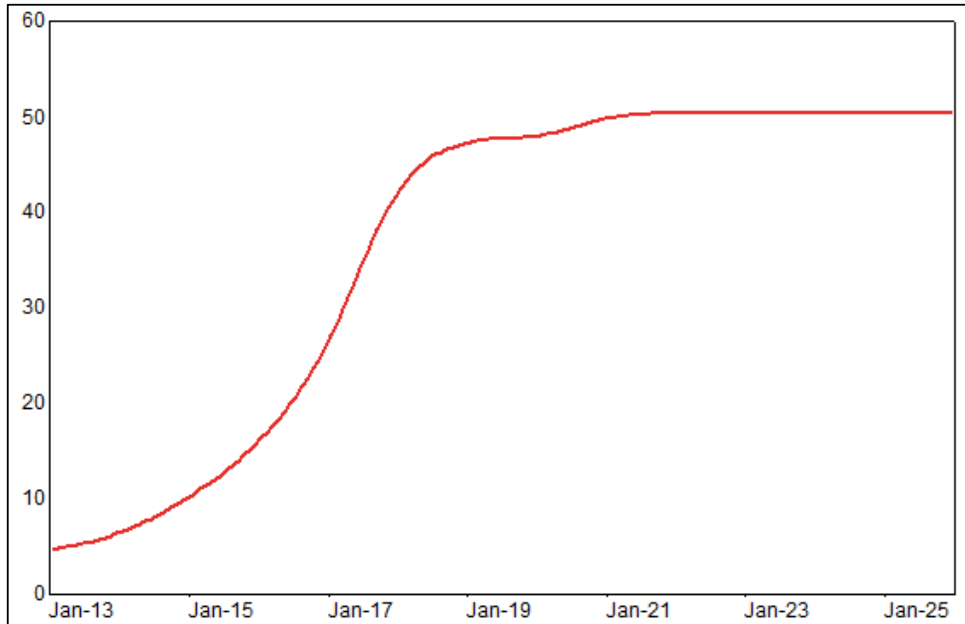
**Figure 9: Residential XOther Variable**



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 summer months and slightly more refrigeration and freezer loads occur in the summer months than winter months.

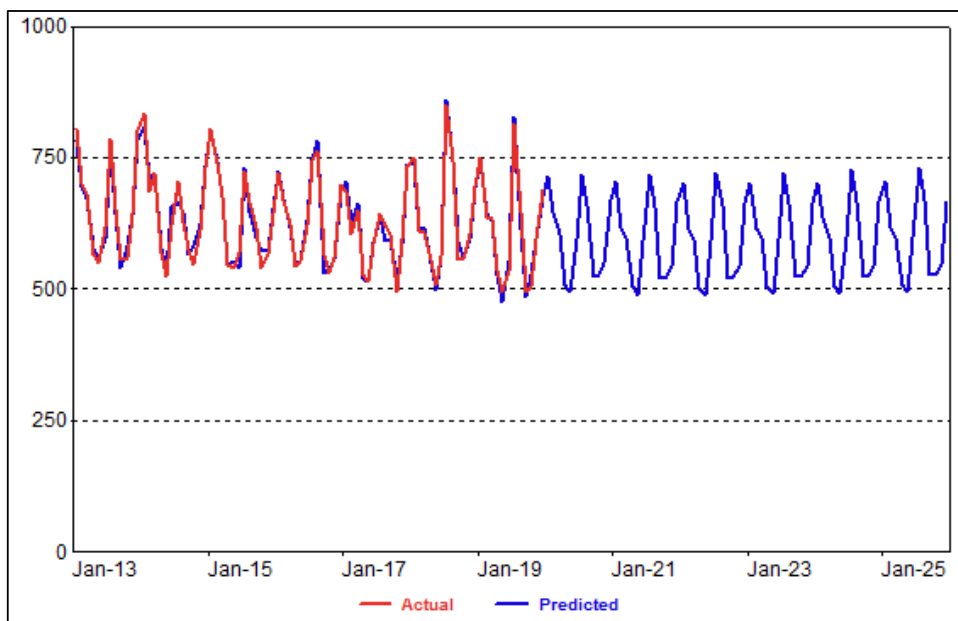
Cumulative CDM starts in 2013 at an estimated average per customer 5 kWh per month (60 kWh per year) and increases to 48 kWh per month (576 kWh per year) by 2019. Projected CDM growth slows considerably after 2019 reaching 50 kWh per month by 2021. Figure 10 shows the residential per customer CDM projections.

**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)**



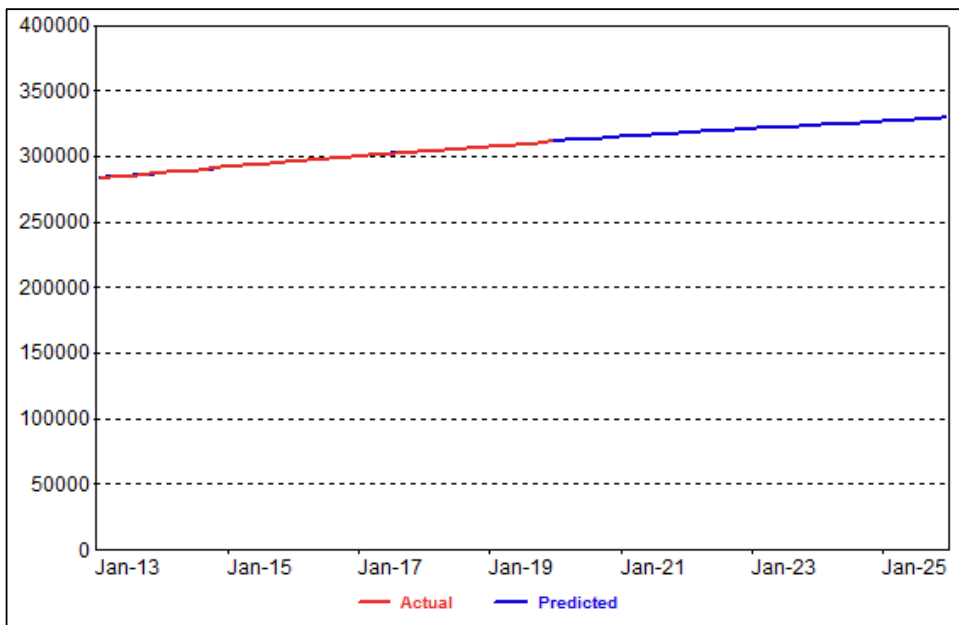
The estimated model explains historical sales well with an Adjusted R-Squared of 0.96 and a mean absolute percent error (MAPE) of 2.0%. The model variables are all strongly statistically significant. The model also includes binary variables for March, April, May, and November and shifts in usage in 2015 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:

$$ComSales_m = B_0 + B_1XHeat_m + B_2XCool_m + B_3XOther_m + B_4CDM_m + e_m$$

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

Where:

EI = Annual energy intensity (kWh per square feet)

EconVar<sub>m</sub> = 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:

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

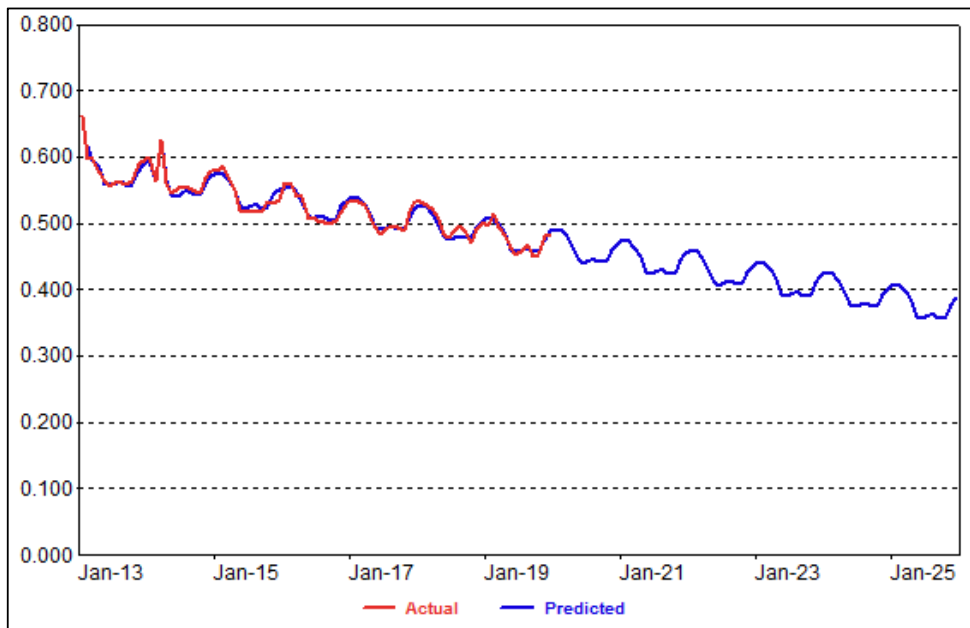
The weights are determined by evaluating out of sample model fit statistics for different sets of weight. The variables are geometrically weighted as population and GDP are measured on different scales.

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.

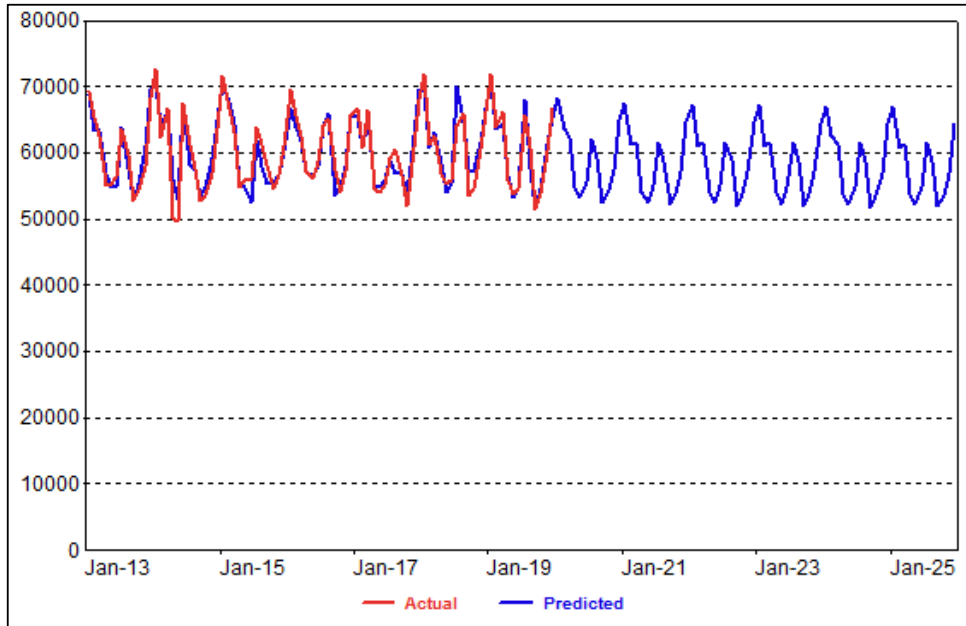
#### **Figure 14 to**

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.

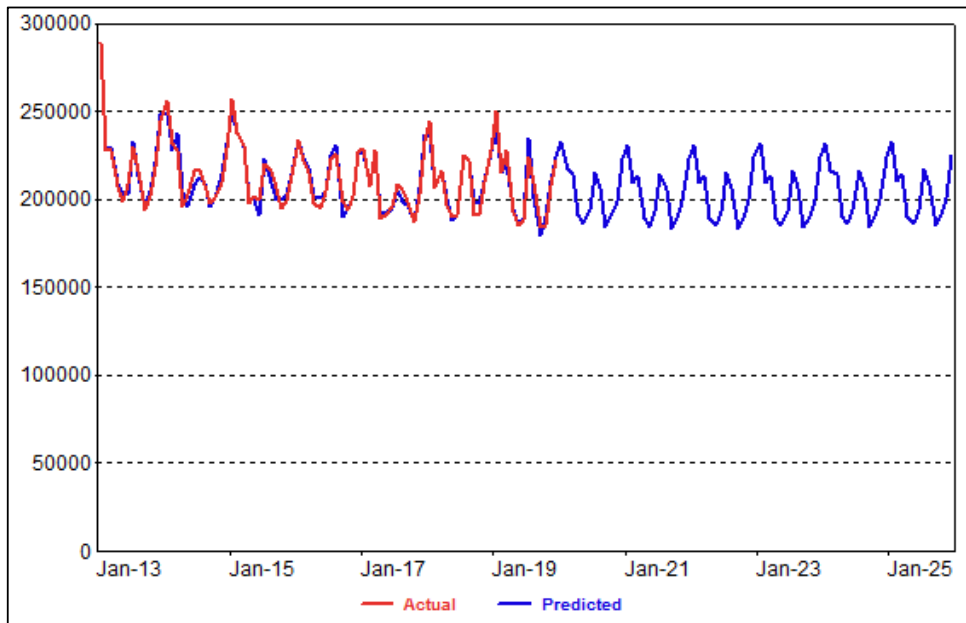
**HYDRO OTTAWA**



**Figure 14: Actual and Predicted GS50 Sales (MWh)**



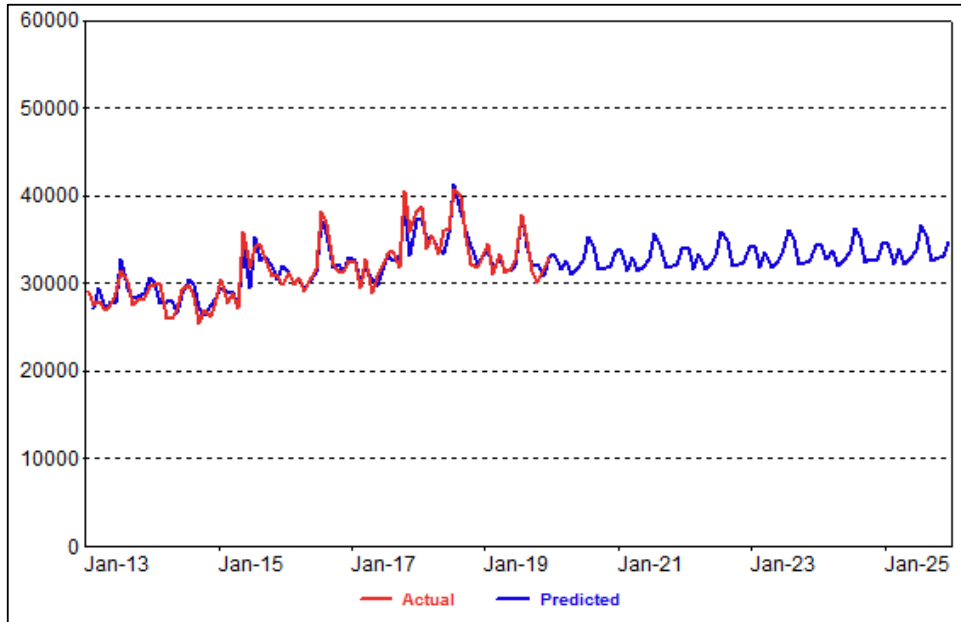
**Figure 15: Actual and Predicted GS1000 Sales (MWh)**



**HYDRO OTTAWA**

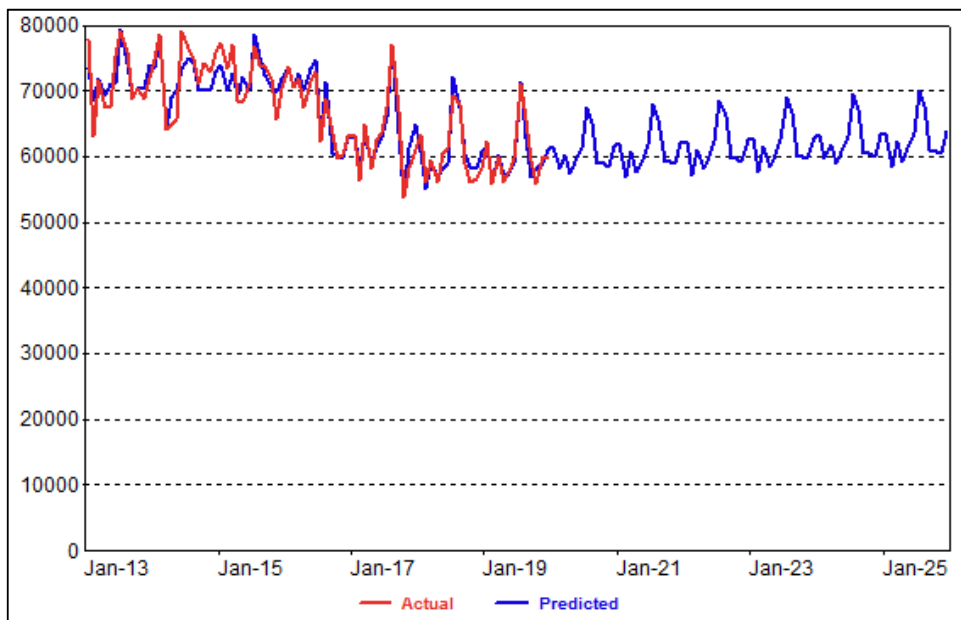


**Figure 16: Actual and Predicted GS1500 Sales (MWh)**



\* 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		GS 1000		GS 1500		GS 5000	
		chg		chg		chg		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.

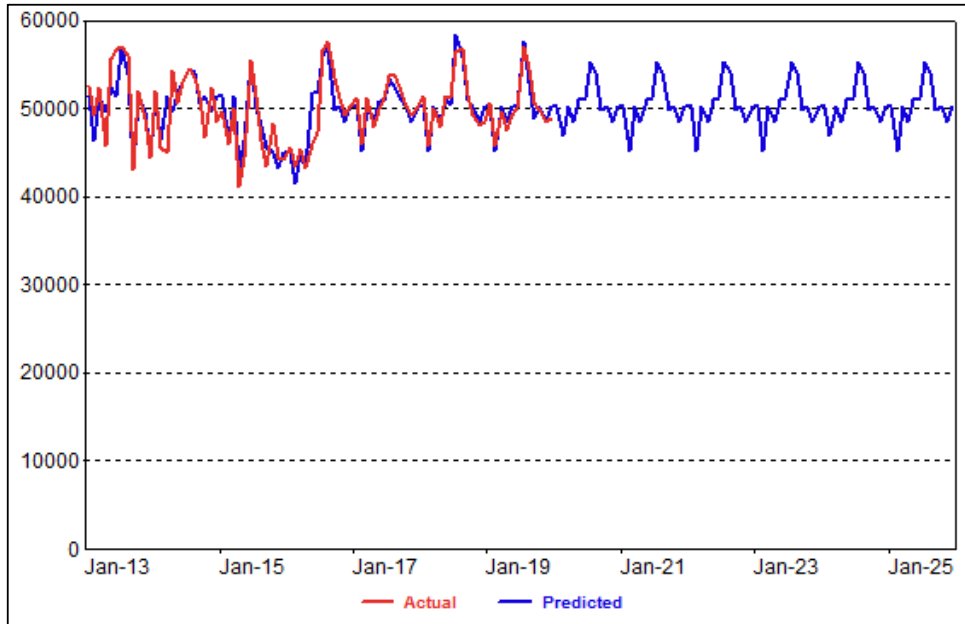
**Table 7: Commercial Customer Forecast**

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.

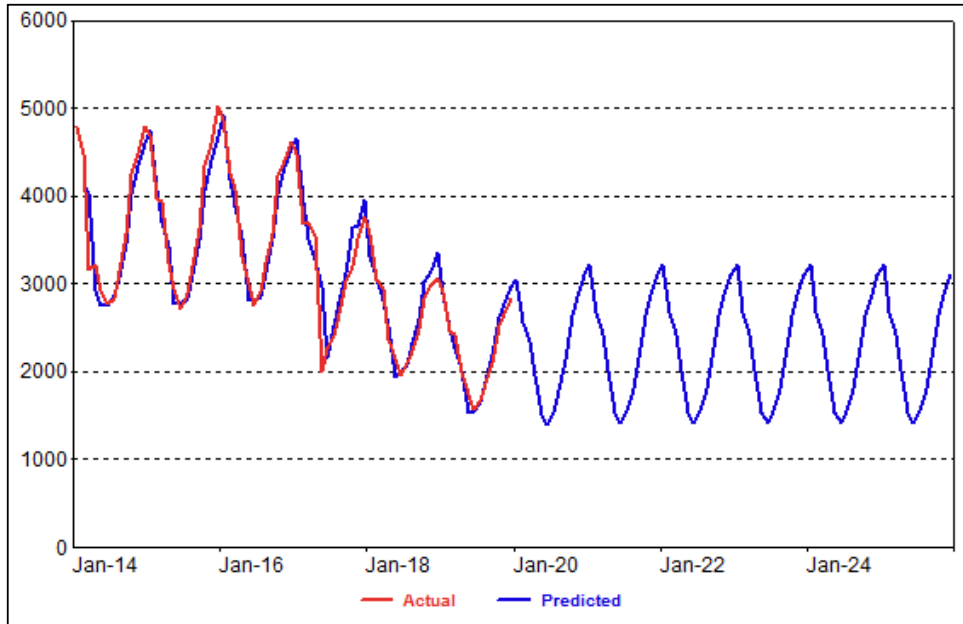
**Figure 18: Actual and Predicted Large Users (MWh)**



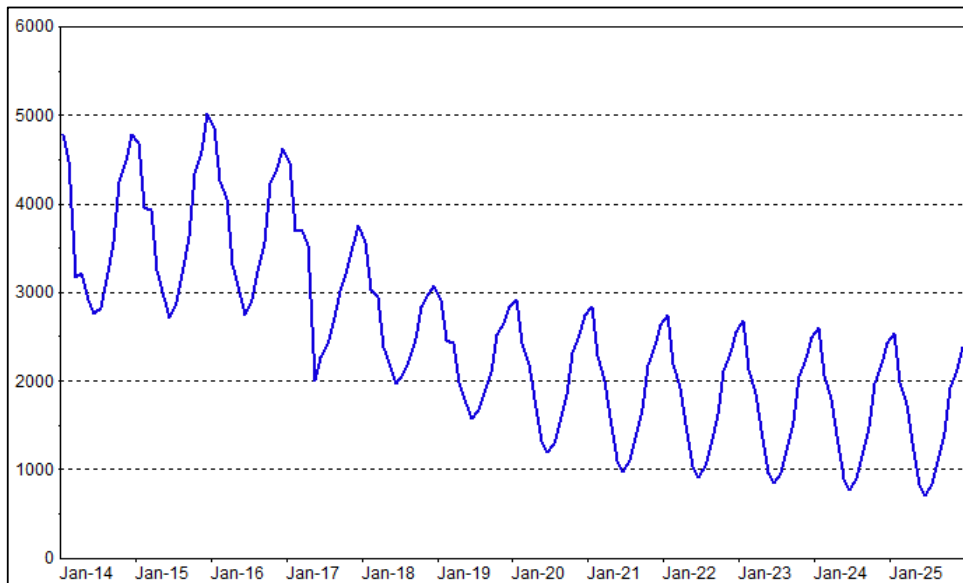
\* Predicted value excludes the impact of CDM, adjustment made outside of model

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.



### 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.

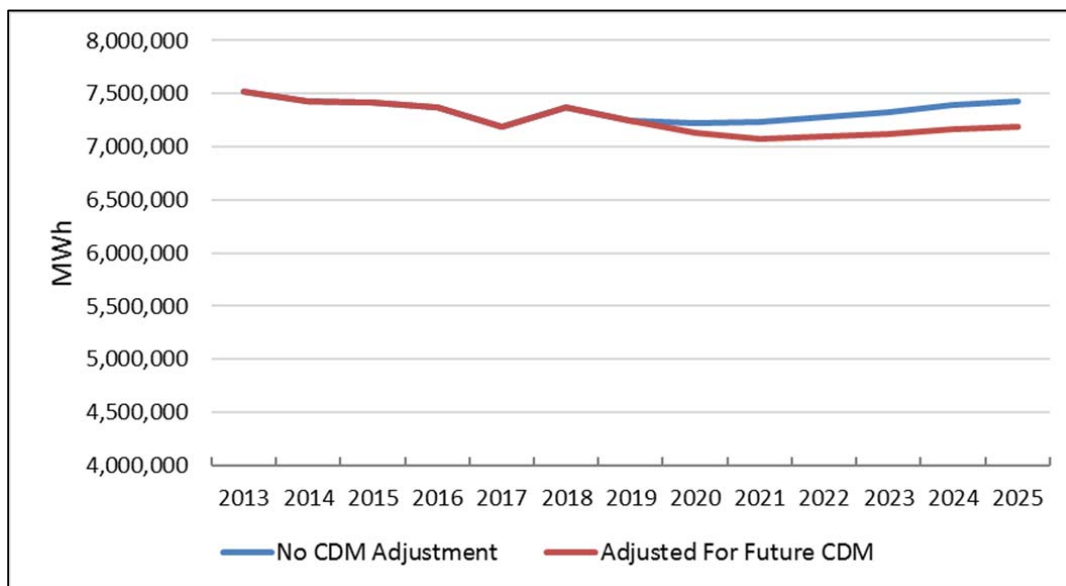
In the residential model the CDM coefficient is -0.70. This implies that 30% of the CDM savings is already accounted for in the end-use intensity trends and estimated coefficients on

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:

$$CoolVar_m = CoolLoad_m \times PkTDD_m$$

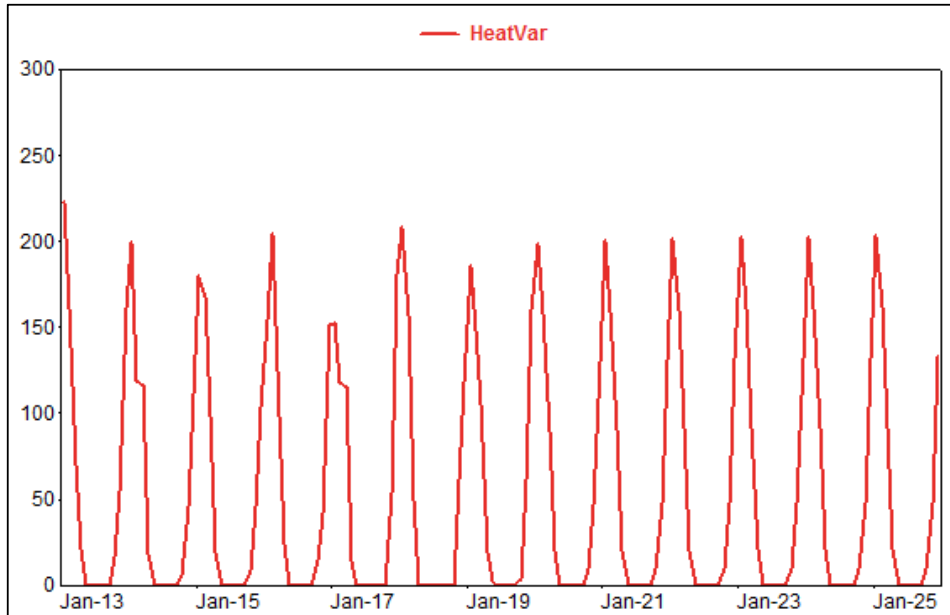
Where

$$CoolLoad_m = B_2 \times NrmXCool_m \text{ (Derived from the estimated rate class models)}$$

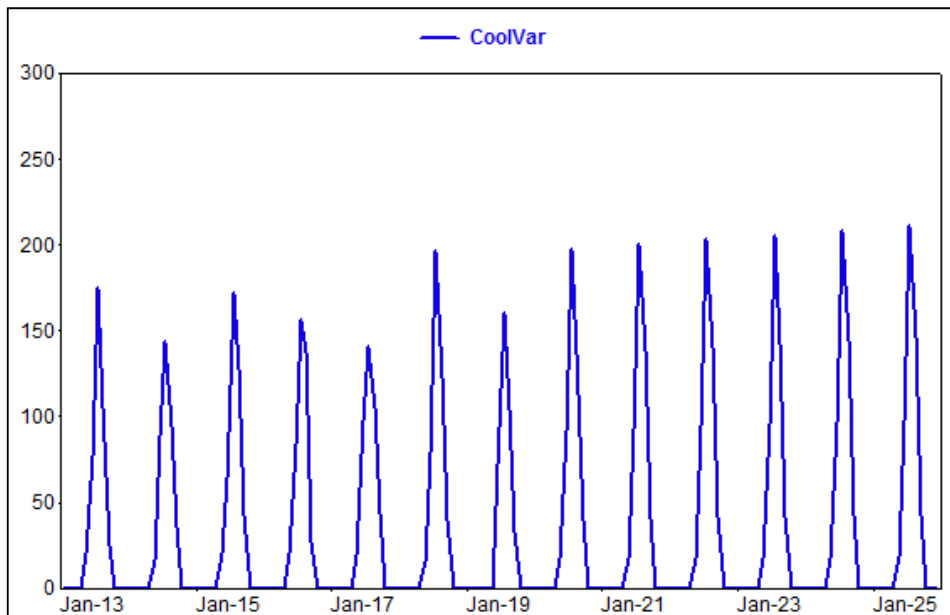
$$PkTDD_m = \text{Peak-day THI degree-day}$$

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

**Figure 22: Peak XHeat Variable**



**Figure 23: Peak XCool Variable**



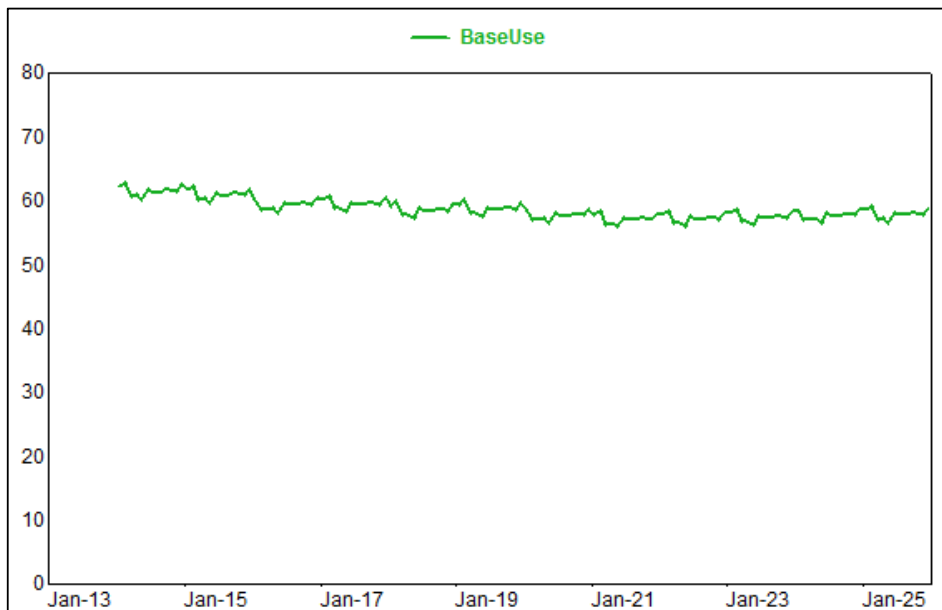
**BaseVar Model Variable**

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)**

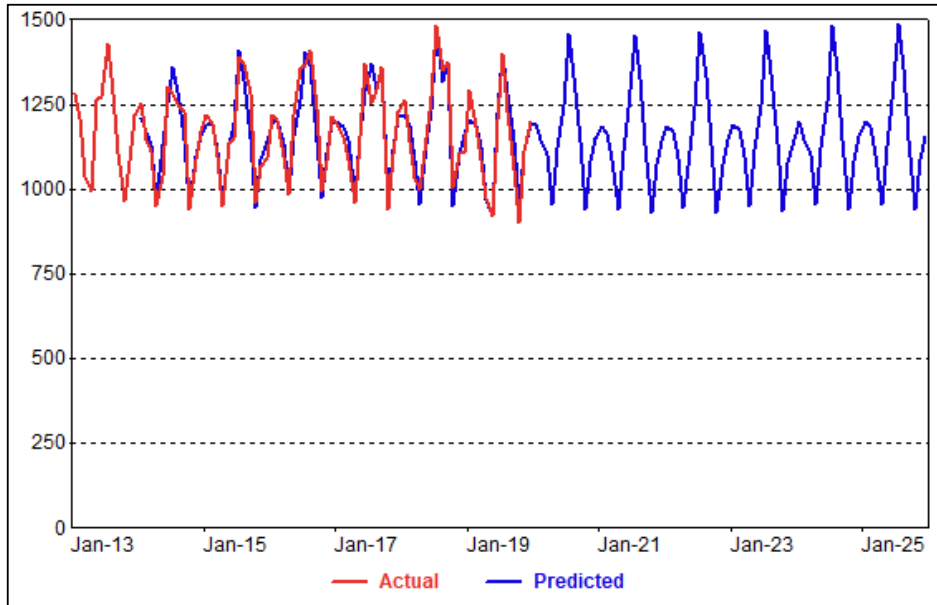


Table 9 shows system purchase and peak demand forecast.

**Table 9: System Forecast**

Year	System Purchases		Peak Demand	
	(MWh)	chg	(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



## HYDRO OTTAWA



### 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

## HYDRO OTTAWA



### 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

## HYDRO OTTAWA



### 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

## HYDRO OTTAWA



### 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

## HYDRO OTTAWA



### 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

## HYDRO OTTAWA



### 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

## HYDRO OTTAWA



### 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

## HYDRO OTTAWA



### 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



**HYDRO OTTAWA**



**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

## HYDRO OTTAWA



### 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

## HYDRO OTTAWA



### 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

## HYDRO OTTAWA



### 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

## LOAD FORECAST

Please refer to the Excel files attached:

- Attachment 3-1-1 (D): 1. Load Forecast Data – Customers
- Attachment 3-1-1 (D): 2. Load Forecast Data – kWh
- Attachment 3-1-1 (D): 3. Load Forecast Data - kW

## 1 **UPDATED ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSES**

### 3 **1. INTRODUCTION**

4 Hydro Ottawa's last rebasing application was filed in April 2015 for a Custom Incentive  
5 Rate-Setting ("Custom IR") framework for the 2016-2020 period.<sup>1</sup> As per the OEB Decision and  
6 Order and Approved Settlement Agreement governing the utility's 2016-2020 rate plan, Hydro  
7 Ottawa has used the detailed five-year load forecast that was included in the original 2016-2020  
8 rebasing application for each of the annual rate adjustment applications which was submitted to  
9 the OEB over the course of the corresponding rate term.<sup>2</sup>

10  
11 As outlined in **UPDATED** Exhibit 3-1-1: Load Forecast, Hydro Ottawa has prepared a new  
12 five-year detailed load forecast for the 2021-2025 period, as part of this Application. Hydro  
13 Ottawa retained the services of a third-party expert (Itron) for the purpose of preparing this load  
14 forecast. The utility confirms that it did not develop a detailed load forecast in between the filings  
15 of its 2016-2020 and 2021-2025 Custom IR applications.

### 17 **2. HISTORICAL ACCURACY OF LOAD FORECAST**

18 Hydro Ottawa has provided **UPDATED** Attachment 3-1-1(A): Appendix 2-IB - Load Forecast  
19 Analysis, which summarizes the data and develops year-over-year trends in historical and  
20 forecast customer counts, consumption, demand, and revenues. The utility completed Appendix  
21 2-IB, as originally submitted, with the following inputs:

- 23 • 2016-2018 actual sales, demand, customer count and connections, and distribution  
24 revenue;
- 25 • 2016-2018 actual weather-normalized sales and demand;
- 26 • 2019-2020 updated load forecast and approved distribution revenue; and
- 27 • 2021-2025 proposed load forecast and proposed distribution revenue.

28 <sup>1</sup> Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April  
29 29, 2015).

30 <sup>2</sup> Ontario Energy Board, *Decision and Order*, EB-2015-0004 (December 22, 2015).

1 Hydro Ottawa completed the UPDATED Appendix 2-IB with the following inputs:

2

- 3 • 2016-2019 actual sales, demand, customer count and connections, and distribution
- 4 revenue;
- 5 • 2016-2019 actual weather-normalized sales and demand;
- 6 • 2020 updated load forecast and approved distribution revenue; and
- 7 • 2021-2025 proposed load forecast and proposed distribution revenue.

8

9 For details regarding the class level assumptions and data sources in the load forecast, please  
10 see UPDATED Attachment 3-1-1(A): Appendix 2-IB - Load Forecast Analysis, which provides  
11 year-over-year trending of key components of the load forecast, as follows:

- 12 • Customers / connections
- 13 • Historical, actual, and weather-normalized load (kWh)
- 14 • Consumption per customer / connection
- 15 • Demand (kW)
- 16 • Revenue

17 The following observations can be derived through the analyses included in Appendix 2-IB:

18

- 19 • Consumption (kWh) will rise through the 2021-2025 forecast period, while remaining
- 20 lower than the peak year of 2016;
- 21 • Demand (kW) shows a gradual downward trend on average throughout the forecast
- 22 period; and
- 23 • Customer count and connections are set to continue following expected trends, in line
- 24 with anticipated growth in the City of Ottawa's population.

25

26 Tables 1 through 12 in this Schedule summarize Hydro Ottawa's 2016-2020 OEB-approved load  
27 forecast and compare its data to both 2016-2018 Historical and 2019-2020 Bridge Year data. As

1 part of the update for 2019 actuals, Hydro Ottawa has provided 2019 Historical data, where  
2 applicable, for Tables 1 through 12.

3

4 Table 1 below provides Hydro Ottawa's energy sales forecast by MWh for 2016-2020.

5

6 **Table 1 – 2016-2020 Energy Sales Forecast By Customer Class (MWh)**

	2016	2017	2018	2019	2020
Residential	2,216,045	2,198,259	2,206,411	2,214,984	2,217,628
General Service < 50 kW	726,360	716,896	709,791	704,193	699,744
General Service 50 to 1,499 kW Non Interval	2,954,441	2,907,445	2,875,422	2,852,593	2,835,387
General Service 1,500 to 4,999 kW	863,309	877,400	895,369	914,569	935,554
Large Use	620,218	619,253	618,467	617,036	615,195
Street Lighting	43,552	43,653	43,765	43,876	44,015
Unmetered Scattered Load	16,651	16,690	16,731	16,772	16,827
Sentinel Lighting	48	48	48	48	48
<b>TOTAL MWh SALES</b>	<b>7,440,624</b>	<b>7,379,644</b>	<b>7,366,004</b>	<b>7,364,071</b>	<b>7,364,398</b>

7

8 The updated version of Table 2 below provides Hydro Ottawa's actual energy sales by MWh for  
9 2016-2020 and facilitates comparisons with the information presented in Table 1 above.



1 **Table 2 – AS ORIGINALLY SUBMITTED – 2016-2020 Weather-Normalized Actual Sales**  
2 **Forecast by Customer Class (MWh)**

	2016	2017	2018	2019	2020
Residential	2,203,868	2,232,964	2,227,860	2,263,788	2,254,563
General Service < 50 kW	724,984	719,547	712,044	724,602	707,799
General Service 50 to 1,499 kW Non Interval	2,890,997	2,899,049	2,882,228	2,884,379	2,839,873
General Service 1,500 to 4,999 kW	797,371	759,003	712,925	723,102	701,795
Large Use	584,167	609,177	603,448	602,082	588,828
Street Lighting	45,206	38,204	31,723	26,728	24,064
Unmetered Scattered Load	15,659	15,231	14,861	14,550	14,106
Sentinel Lighting	47	47	47	47	47
<b>TOTAL MWh SALES</b>	<b>7,262,299</b>	<b>7,273,222</b>	<b>7,185,136</b>	<b>7,239,278</b>	<b>7,131,075</b>

3

4 **Table 2 – UPDATED FOR 2019 ACTUALS – 2016-2020 Weather-Normalized Actual Sales**  
5 **Forecast by Customer Class (MWh)**

	2016	2017	2018	2019	2020
Residential	2,203,863	2,232,966	2,227,858	2,256,9818	2,254,424
General Service < 50 kW	724,984	719,547	712,045	720,536	707,564
General Service 50 to 1,499 kW Non Interval	2,890,997	2,899,051	2,882,252	2,870,031	2,838,242
General Service 1,500 to 4,999 kW	797,371	759,004	712,925	724,066	701,743
Large Use	584,167	609,177	603,448	603,590	588,828
Street Lighting	45,206	38,204	31,723	26,728	24,064
Unmetered Scattered Load	15,659	15,231	14,861	14,550	14,106
Sentinel Lighting	47	47	47	47	47
<b>TOTAL MWh SALES</b>	<b>7,262,272</b>	<b>7,273,227</b>	<b>7,185,159</b>	<b>7,216,529</b>	<b>7,129,018</b>

6

1 Table 3 provides the variance value between the forecast and the actuals shown above in  
2 Tables 1 and 2 (as updated for 2019 actuals, where applicable).

3

4 **Table 3 – AS ORIGINALLY SUBMITTED – Variance in 2016-2020 Forecast vs.**

5

**Weather-Normalized Actual Sales (MWh)**

	2016	2017	2018	2019	2020
Residential	-12,181	34,705	21,449	48,804	36,935
General Service < 50 kW	-1,376	2,651	2,253	20,409	8,055
General Service 50 to 1,499 kW Non Interval	-63,444	-8,396	6,806	31,786	4,486
General Service 1,500 to 4,999 kW	-65,938	-118,397	-182,444	-191,467	-233,759
Large Use	-36,051	-10,076	-15,019	-14,954	-26,367
Street Lighting	1,654	-5,449	-12,042	-17,148	-19,951
Unmetered Scattered Load	-992	-1,459	-1,870	-2,222	-2,721
Sentinel Lighting	-1	-1	-1	-1	-1
<b>TOTAL MWh SALES</b>	<b>-178,325</b>	<b>-106,422</b>	<b>-180,868</b>	<b>-124,793</b>	<b>-233,323</b>

6

7 **Table 3 – UPDATED FOR 2019 ACTUALS – Variance in 2016-2020 Forecast vs.**

8

**Weather-Normalized Actual Sales (MWh)**

	2016	2017	2018	2019	2020
Residential	-12,182	34,707	21,447	41,997	36,796
General Service < 50 kW	-1,376	2,651	2,254	16,343	7,820
General Service 50 to 1,499 kW Non Interval	-63,465	-8,394	6,830	17,438	2,855
General Service 1,500 to 4,999 kW	-65,939	-118,396	-182,444	-190,503	-233,811
Large Use	-36,051	-10,076	-15,019	-13,446	-26,367
Street Lighting	1,654	-5,449	-12,042	-17,148	-19,951
Unmetered Scattered Load	-992	-1,459	-1,870	-2,222	-2,721
Sentinel Lighting	-1	-1	-1	-1	-1
<b>TOTAL MWh SALES</b>	<b>-178,353</b>	<b>-106,417</b>	<b>-180,845</b>	<b>-147,542</b>	<b>-235,380</b>

9

10

1 The updated version of Table 4 provides the percentage change between the forecast and the  
2 actuals that is illustrated in Table 3, as updated, above.

3

4 **Table 4 – AS ORIGINALLY SUBMITTED – 2016-2020 Forecast vs. Weather-Normalized**  
5 **Actual Sales - % Change (MWh)**

	2016	2017	2018	2019	2020
Residential	-0.55%	1.58%	0.97%	2.20%	1.67%
General Service < 50 kW	-0.19%	0.37%	0.32%	2.90%	1.15%
General Service 50 to 1,499 kW Non Interval	-2.15%	-0.29%	0.24%	1.11%	0.16%
General Service 1,500 to 4,999 kW	-7.64%	-13.49%	-20.38%	-20.94%	-24.99%
Large Use	-5.81%	-1.63%	-2.43%	-2.42%	-4.29%
Street Lighting	3.80%	-12.48%	-27.52%	-39.08%	-45.33%
Unmetered Scattered Load	-5.96%	-8.74%	-11.18%	-13.25%	-16.17%
Sentinel Lighting	-2.08%	-2.08%	-2.08%	-2.08%	-2.08%
<b>TOTAL MWh SALES</b>	<b>-2.40%</b>	<b>-1.44%</b>	<b>-2.46%</b>	<b>-1.69%</b>	<b>-3.17%</b>

6

7 **Table 4 – UPDATED FOR 2019 ACTUALS – 2016-2020 Forecast vs. Weather-Normalized**  
8 **Actual Sales - % Change (MWh)**

	2016	2017	2018	2019	2020
Residential	-0.55%	1.58%	0.97%	1.90%	1.66%
General Service < 50 kW	-0.19%	0.37%	0.32%	2.32%	1.12%
General Service 50 to 1,499 kW Non Interval	-2.15%	-0.29%	0.24%	0.62%	0.10%
General Service 1,500 to 4,999 kW	-7.64%	-13.49%	-20.38%	-20.83%	-24.99%
Large Use	-5.81%	-1.63%	-2.43%	-2.18%	-4.29%
Street Lighting	3.80%	-12.48%	-27.52%	-39.08%	-45.33%
Unmetered Scattered Load	-5.96%	-8.74%	-11.18%	-13.25%	-16.17%
Sentinel Lighting	-2.08%	-2.08%	-2.08%	-2.08%	-2.08%
<b>TOTAL MWh SALES</b>	<b>-2.40%</b>	<b>-1.44%</b>	<b>-2.46%</b>	<b>-2.00%</b>	<b>-3.20%</b>

9

10 Table 5 below provides Hydro Ottawa's demand sales forecast by kW for 2016-2020.

1 **Table 5 – 2016-2020 Demand Sales Forecast by Customer Class (kW)**

	2016	2017	2018	2019	2020
General Service 50 to 1,499 kW Non Interval	7,027,979	6,908,640	6,824,350	6,761,930	6,711,579
General Service 1,500 to 4,999 kW	1,847,365	1,877,691	1,916,044	1,957,009	2,001,525
Large Use	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342
Street Lighting	123,144	123,144	123,144	123,144	123,144
Sentinel Lighting	216	216	216	216	216
<b>TOTAL KW DEMAND SALES</b>	<b>10,120,153</b>	<b>10,029,417</b>	<b>9,982,054</b>	<b>9,958,001</b>	<b>9,948,806</b>

2

3 The updated version of Table 6 below provides Hydro Ottawa's actual demand sales by kW for  
 4 2016-2020.

1 **Table 6 – AS ORIGINALLY SUBMITTED – 2016-2020 Weather-Normalized Actual Demand**  
2 **Sales by Customer Class (kW)**

	2016	2017	2018	2019	2020
General Service 50 to 1,499 kW Non Interval	7,006,074	7,015,544	6,960,266	6,930,957	6,867,852
General Service 1,500 to 4,999 kW	1,729,271	1,648,910	1,547,429	1,572,857	1,552,781
Large Use	1,070,337	1,114,963	1,104,851	1,105,225	1,075,011
Street Lighting	125,465	106,296	88,707	74,394	67,032
Sentinel Lighting	132	132	132	132	132
<b>TOTAL KW DEMAND SALES</b>	<b>9,931,279</b>	<b>9,885,845</b>	<b>9,701,385</b>	<b>9,683,565</b>	<b>9,562,808</b>

3  
4 **Table 6 – UPDATED FOR 2019 ACTUALS – 2016-2020 Weather-Normalized Actual**  
5 **Demand Sales by Customer Class (kW)**

	2016	2017	2018	2019	2020
General Service 50 to 1,499 kW Non Interval	7,020,354	7,028,949	6,973,449	6,937,927	6,866,524
General Service 1,500 to 4,999 kW	1,731,827	1,650,012	1,548,930	1,573,758	1,551,714
Large Use	1,061,398	1,105,747	1,095,710	1,096,064	1,075,011
Street Lighting	125,465	106,296	88,707	74,394	67,032
Sentinel Lighting	132	132	132	132	132
<b>TOTAL KW DEMAND SALES</b>	<b>9,939,1769</b>	<b>9,891,136</b>	<b>9,706,928</b>	<b>9,682,275</b>	<b>9,560,413</b>

6  
7 The updated version of Table 7 below provides the variance value between the forecast and the  
8 actuals, in relation to 2016-2020 demand sales.

1 **Table 7 – AS ORIGINALLY SUBMITTED – Variance in 2016-2020 Forecast vs.**  
2 **Weather-Normalized Actual Sales (kW)**

	2016	2017	2018	2019	2020
General Service 50 to 1,499 kW Non Interval	(21,905)	106,904	135,916	169,027	156,273
General Service 1,500 to 4,999 kW	(118,094)	(228,781)	(368,615)	(384,152)	(448,744)
Large Use	(51,112)	(4,763)	(13,449)	(10,477)	(37,331)
Street Lighting	2,321	(16,848)	(34,437)	(48,750)	(56,112)
Sentinel Lighting	(84)	(84)	(84)	(84)	(84)
<b>TOTAL KW DEMAND SALES</b>	<b>(188,874)</b>	<b>(143,572)</b>	<b>(280,669)</b>	<b>(274,436)</b>	<b>(385,998)</b>

3  
4 **Table 7 – UPDATED FOR 2019 ACTUALS – Variance in 2016-2020 Forecast vs.**  
5 **Weather-Normalized Actual Sales (kW)**

	2016	2017	2018	2019	2020
General Service 50 to 1,499 kW Non Interval	(7,625)	120,309	149,099	175,997	154,945
General Service 1,500 to 4,999 kW	(115,538)	(227,679)	(367,114)	(383,251)	(449,811)
Large Use	(60,051)	(13,979)	(22,590)	(19,638)	(37,331)
Street Lighting	2,321	(16,848)	(34,437)	(48,750)	(56,112)
Sentinel Lighting	(84)	(84)	(84)	(84)	(84)
<b>TOTAL KW DEMAND SALES</b>	<b>(180,977)</b>	<b>(138,281)</b>	<b>(275,126)</b>	<b>(275,726)</b>	<b>(388,393)</b>

6  
7 The updated version of Table 8 below provides the percentage change between the forecast  
8 and the actuals that is illustrated in Table 7, as updated above.

1 **Table 8 – AS ORIGINALLY SUBMITTED – 2016-2020 Forecast vs. Weather-Normalized**  
2 **Actual Sales - % Change (kW)**

	2016	2017	2018	2019	2020
General Service 50 to 1,499 kW Non Interval	-0.31%	1.55%	1.99%	2.50%	2.33%
General Service 1,500 to 4,999 kW	-6.39%	-12.18%	-19.24%	-19.63%	-22.42%
Large Use	-4.56%	-0.43%	-1.20%	-0.94%	-3.36%
Street Lighting	1.88%	-13.68%	-27.96%	-39.59%	-45.57%
Sentinel Lighting	-38.89%	-38.89%	-38.89%	-38.89%	-38.89%
<b>TOTAL KW DEMAND SALES</b>	<b>-1.87%</b>	<b>-1.43%</b>	<b>-2.81%</b>	<b>-2.76%</b>	<b>-3.88%</b>

3  
4 **Table 8 – UPDATED FOR 2019 ACTUALS – 2016-2020 Forecast vs. Weather-Normalized**  
5 **Actual Sales - % Change (kW)**

	2016	2017	2018	2019	2020
General Service 50 to 1,499 kW Non Interval	-0.11%	1.74%	2.18%	2.60%	2.31%
General Service 1,500 to 4,999 kW	-6.25%	-12.13%	-19.16%	-19.58%	-22.47%
Large Use	-5.35%	-1.25%	-2.02%	-1.76%	-3.36%
Street Lighting	1.88%	-13.68%	-27.96%	-39.59%	-45.57%
Sentinel Lighting	-38.89%	-38.89%	-38.89%	-38.89%	-38.89%
<b>TOTAL KW DEMAND SALES</b>	<b>-1.79%</b>	<b>-1.38</b>	<b>-2.76%</b>	<b>-2.77%</b>	<b>-3.90%</b>

6  
7 Table 9 below provides the forecast for Hydro Ottawa's average number of customers for the  
8 2016-2020 period.

1 **Table 9 – 2016-2020 Forecast Average Number of Customers and Connections by Class**

	2016	2017	2018	2019	2020
Residential	297,343	301,258	305,144	308,990	312,786
General Service < 50 kW	24,512	24,626	24,739	24,850	24,959
General Service 50 to 1,499 kW Non Interval	3,296	3,323	3,351	3,380	3,408
General Service 1,500 to 4,999 kW	76	76	76	76	76
Large Use	11	11	11	11	11
<b>TOTAL CUSTOMERS</b>	<b>325,238</b>	<b>329,294</b>	<b>333,321</b>	<b>337,307</b>	<b>341,240</b>

2

	2016	2017	2018	2019	2020
Street Lighting	55,516	55,516	55,516	55,516	55,516
Sentinel Lighting	55	51	47	43	39
Unmetered Scattered Load	3,477	3,525	3,573	3,621	3,669
<b>TOTAL CONNECTIONS</b>	<b>59,048</b>	<b>59,092</b>	<b>59,136</b>	<b>59,180</b>	<b>59,224</b>

3

4 Table 10 provides actuals for the utility's total customer and connections count for 2016-2020.



1 **Table 10 – 2016-2020 Actual Number of Customers and Connections by Class<sup>3</sup>**

	2016	2017	2018	2019	2020
Residential	298,001	301,839	305,390	309,165	313,134
General Service < 50 kW	24,623	24,786	24,926	25,030	25,200
General Service 50 to 1,499 kW Non Interval	3,208	3,216	3,223	3,181	3,146
General Service 1,500 to 4,999 kW	72	74	68	67	68
Large Use	11	12	13	11	11
<b>TOTAL CUSTOMERS</b>	<b>325,915</b>	<b>329,927</b>	<b>333,620</b>	<b>337,454</b>	<b>341,559</b>

2

	2016	2017	2018	2019	2020
Street Lighting	58,588	58,470	59,286	60,538	61,886
Sentinel Lighting	62	58	57	55	55
Unmetered Scattered Load	3,416	3,433	3,440	3,382	3,321
<b>TOTAL CONNECTIONS</b>	<b>62,066</b>	<b>61,961</b>	<b>62,783</b>	<b>63,975</b>	<b>65,262</b>

3

4 Table 11 provides the variance value between the forecast and the actuals, in relation to  
5 2016-2020 customer and connections count.

6 <sup>3</sup> 2019 and 2020 are Bridge Year Updated Load forecast numbers.

1 **Table 11 – Variance in 2016-2020 Forecast vs. Actual Customer and Connections Count**

	2016	2017	2018	2019	2020
Residential	658	581	246	175	348
General Service < 50 kW	111	160	187	180	241
General Service 50 to 1,499 kW Non Interval	(88)	(107)	(128)	(199)	(262)
General Service 1,500 to 4,999 kW	(4)	(2)	(8)	(9)	(8)
Large Use	-	1	2	-	-
<b>TOTAL CUSTOMERS</b>	<b>677</b>	<b>633</b>	<b>299</b>	<b>147</b>	<b>319</b>

2

	2016	2017	2018	2019	2020
Street Lighting	3,072	2,954	3,770	5,022	6,370
Sentinel Lighting	7	7	10	12	16
Unmetered Scattered Load	(61)	(92)	(133)	(239)	(348)
<b>TOTAL CONNECTIONS</b>	<b>3,018</b>	<b>2,869</b>	<b>3,647</b>	<b>4,795</b>	<b>6,038</b>

3

4 Table 12 below provides the percentage change between the forecast and the actuals that is  
5 illustrated in Table 11 above.

1 **Table 12 – 2016-2020 Forecast vs. Actual Customer and Connections Count - % Change**

	2016	2017	2018	2019	2020
Residential	0.22%	0.19%	0.08%	0.06%	0.11%
General Service < 50 kW	0.45%	0.65%	0.76%	0.72%	0.97%
General Service 50 to 1,499 kW Non Interval	-2.67%	-3.22%	-3.82%	-5.89%	-7.69%
General Service 1,500 to 4,999 kW	-5.26%	-2.63%	-10.53%	-11.84%	-10.53%
Large Use	0.00%	9.09%	18.18%	0.00%	0.00%
<b>TOTAL CUSTOMERS</b>	<b>0.21%</b>	<b>0.19%</b>	<b>0.09%</b>	<b>0.04%</b>	<b>0.09%</b>

2

	2016	2017	2018	2019	2020
Street Lighting	5.53%	5.32%	6.79%	9.05%	11.47%
Sentinel Lighting	12.73%	13.73%	21.28%	27.91%	41.03%
Unmetered Scattered Load	-1.75%	-2.61%	-3.72%	-6.60%	-9.48%
<b>TOTAL CONNECTIONS</b>	<b>5.11%</b>	<b>4.86%</b>	<b>6.17%</b>	<b>8.10%</b>	<b>10.20%</b>

3

- 4 Hydro Ottawa has confidence that the variances identified in the foregoing analyses are within
- 5 an acceptable range of tolerance.

**Table 1 – Hydro Ottawa 2016 through 2020 Forecasted Sales Forecast (MWh) by class**

	2016	2017	2018	2019	2020
Residential	2,216,045	2,198,259	2,206,411	2,214,984	2,217,628
GS < 50 kW	726,360	716,896	709,791	704,193	699,744
GS > 50 to 1,499 kW	2,954,441	2,907,445	2,875,422	2,852,593	2,835,387
GS > 1,500 to 4,999 kW	863,309	877,400	895,369	914,569	935,554
Large Use	620,218	619,253	618,467	617,036	615,195
Street Lighting	43,552	43,653	43,765	43,876	44,015
Unmetered Scattered Load	16,651	16,690	16,731	16,772	16,827
Sentinel Lights	48	48	48	48	48
Total mWH Sales	7,440,624	7,379,644	7,366,004	7,364,071	7,364,398

**Table 2 – Hydro Ottawa 2016 through 2020 Actual Sales (MWh) by class**

	2016	2017	2018	2019	2020
Residential	2,203,863	2,232,966	2,227,858	2,256,981	2,254,424
GS < 50 kW	724,984	719,547	712,045	720,536	707,564
GS > 50 to 1,499 kW	2,890,976	2,899,051	2,882,252	2,870,031	2,838,242
GS > 1,500 to 4,999 kW	797,370	759,004	712,925	724,066	701,743
Large Use	584,167	609,177	603,448	603,590	588,828
Street Lighting	45,206	38,204	31,723	26,728	24,064
Unmetered Scattered Load	15,659	15,231	14,861	14,550	14,106
Sentinel Lights	47	47	47	47	47
Total mWH Sales	7,262,272	7,273,227	7,185,159	7,216,529	7,129,018

**Table 3 – Hydro Ottawa 2016 through 2020 Forecast vs Actual # Difference (MWh) by class**

	2016	2017	2018	2019	2020
Residential	-12,182	34,707	21,447	41,997	36,796
GS < 50 kW	-1,376	2,651	2,254	16,343	7,820
GS > 50 to 1,499 kW	-63,465	-8,394	6,830	17,438	2,855
GS > 1,500 to 4,999 kW	-65,939	-118,396	-182,444	-190,503	-233,811
Large Use	-36,051	-10,076	-15,019	-13,446	-26,367
Street Lighting	1,654	-5,449	-12,042	-17,148	-19,951
Unmetered Scattered Load	-992	-1,459	-1,870	-2,222	-2,721
Sentinel Lights	-1	-1	-1	-1	-1
Total mWH Sales	-178,352	-106,417	-180,845	-147,542	-235,380

**Table 4 – Hydro Ottawa 2016 through 2020 Forecast vs Actual # Difference (MWh) by class**

	2016	2017	2018	2019	2020
Residential	-0.55%	1.58%	0.97%	1.90%	1.66%
GS < 50 kW	-0.19%	0.37%	0.32%	2.32%	1.12%
GS > 50 to 1,499 kW	-2.15%	-0.29%	0.24%	0.61%	0.10%
GS > 1,500 to 4,999 kW	-7.64%	-13.49%	-20.38%	-20.83%	-24.99%
Large Use	-5.81%	-1.63%	-2.43%	-2.18%	-4.29%
Street Lighting	3.80%	-12.48%	-27.52%	-39.08%	-45.33%
Unmetered Scattered Load	-5.96%	-8.74%	-11.18%	-13.25%	-16.17%
Sentinel Lights	-2.08%	-2.08%	-2.08%	-2.08%	-2.08%
Total mWH Sales	-2.40%	-1.44%	-2.46%	-2.00%	-3.20%

**Table 5 – Hydro Ottawa 2016 through 2020 Demand Forecast (kW) by class**

	2016	2017	2018	2019	2020
GS > 50 to 1,499 kW	7,027,979	6,908,640	6,824,350	6,761,930	6,711,579
GS > 1,500 to 4,999 kW	1,847,365	1,877,691	1,916,044	1,957,009	2,001,525
Large User	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342
Street Lighting	123,144	123,144	123,144	123,144	123,144
Sentinel Lights	216	216	216	216	216
Total	10,120,153	10,029,417	9,982,054	9,958,001	9,948,806

**Table 6 – Hydro Ottawa 2016 through 2020 Demand Actual (kW) by class**

	2016	2017	2018	2019	2020
GS > 50 to 1,499 kW	7,020,354	7,028,949	6,973,449	6,937,927	6,866,524
GS > 1,500 to 4,999 kW	1,731,827	1,650,012	1,548,930	1,573,758	1,551,714
Large User	1,061,398	1,105,747	1,095,710	1,096,064	1,075,011
Street Lighting	125,465	106,296	88,707	74,394	67,032
Sentinel Lights	132	132	132	132	132
Total	9,939,176	9,891,136	9,706,928	9,682,275	9,560,413

**Table 7 – Hydro Ottawa 2016 through 2020 Forecast vs Actual (kW) by class**

	2016	2017	2018	2019	2020
GS > 50 to 1,499 kW	(7,625)	120,309	149,099	175,997	154,945
GS > 1,500 to 4,999 kW	(115,538)	(227,679)	(367,114)	(383,251)	(449,811)
Large User	(60,051)	(13,979)	(22,590)	(19,638)	(37,331)
Street Lighting	2,321	(16,848)	(34,437)	(48,750)	(56,112)
Sentinel Lights	(84)	(84)	(84)	(84)	(84)
Total	(180,977)	(138,281)	(275,126)	(275,726)	(388,393)

**Table 8 – Hydro Ottawa 2016 through 2020 Forecast vs Actual (kW) by class**

	2016	2017	2018	2019	2020
GS > 50 to 1,499 kW	-0.11%	1.74%	2.18%	2.60%	2.31%
GS > 1,500 to 4,999 kW	-6.25%	-12.13%	-19.16%	-19.58%	-22.47%
Large User	-5.35%	-1.25%	-2.02%	-1.76%	-3.36%
Street Lighting	1.88%	-13.68%	-27.96%	-39.59%	-45.57%
Sentinel Lights	-38.89%	-38.89%	-38.89%	-38.89%	-38.89%
Total	-1.79%	-1.38%	-2.76%	-2.77%	-3.90%

**Table 9 – Hydro Ottawa 2016 through 2020 Forecasted Average Number of Customers and Connections by class**

	2016	2017	2018	2019	2020
Residential	297,343	301,258	305,144	308,990	312,786
GS < 50 kW	24,512	24,626	24,739	24,850	24,959
GS > 50 to 1,499 kW	3,296	3,323	3,351	3,380	3,408
GS > 1,500 to 4,999 kW	76	76	76	76	76
Large Users	11	11	11	11	11
Total Customers	325,238	329,294	333,321	337,307	341,240
Street Lighting	55,516	55,516	55,516	55,516	55,516
Sentinel Lights	55	51	47	43	39
Unmetered Scattered Loads	3,477	3,525	3,573	3,621	3,669
Total Connections	59,048	59,092	59,136	59,180	59,224

**Table 10 – Hydro Ottawa 2016 through 2020 Actual Number of Customers and Connections by class**

	2016	2017	2018	2019	2020
Residential	298,001	301,839	305,390	309,165	313,134
GS < 50 kW	24,623	24,786	24,926	25,030	25,200
GS > 50 to 1,499 kW	3,208	3,216	3,223	3,181	3,146
GS > 1,500 to 4,999 kW	72	74	68	67	68
Large Users	11	12	13	11	11
Total Customers	325,915	329,927	333,620	337,454	341,559
Street Lighting	58,588	58,470	59,286	60,538	61,886
Sentinel Lights	62	58	57	55	55
Unmetered Scattered Loads	3,416	3,433	3,440	3,382	3,321
Total Connections	62,066	61,961	62,783	63,975	65,262

**Table 11 – Hydro Ottawa 2016 through 2020 Actual Number of Customers and Connections by class**

	2016	2017	2018	2019	2020
Residential	658	581	246	175	348
GS < 50 kW	111	160	187	180	241
GS > 50 to 1,499 kW	(88)	(107)	(128)	(199)	(262)
GS > 1,500 to 4,999 kW	(4)	(2)	(8)	(9)	(8)
Large Users	-	1	2	-	-
Total Customers	677	633	299	147	319
Street Lighting	3,072	2,954	3,770	5,022	6,370
Sentinel Lights	7	7	10	12	16
Unmetered Scattered Loads	(61)	(92)	(133)	(239)	(348)
Total Connections	3,018	2,869	3,647	4,795	6,038

**Table 12 – Hydro Ottawa 2016 through 2020 Actual Number of Customers and Connections by class**

	2016	2017	2018	2019	2020
Residential	0.22%	0.19%	0.08%	0.06%	0.11%
GS < 50 kW	0.45%	0.65%	0.76%	0.72%	0.97%
GS > 50 to 1,499 kW	-2.67%	-3.22%	-3.82%	-5.89%	-7.69%
GS > 1,500 to 4,999 kW	-5.26%	-2.63%	-10.53%	-11.84%	-10.53%
Large Users	0.00%	9.09%	18.18%	0.00%	0.00%
Total Customers	0.21%	0.19%	0.09%	0.04%	0.09%
Street Lighting	5.53%	5.32%	6.79%	9.05%	11.47%
Sentinel Lights	12.73%	13.73%	21.28%	27.91%	41.03%
Unmetered Scattered Loads	-1.75%	-2.61%	-3.72%	-6.60%	-9.48%
Total Connections	5.11%	4.86%	6.17%	8.10%	10.20%



## UPDATED OTHER REVENUE SUMMARY

1

2

### 3 1. INTRODUCTION

4 Other Revenue, also referred to as Revenue Offsets, relates to all utility revenues other than  
5 distribution and cost of power revenues. Hydro Ottawa has classified these into the following  
6 categories: Specific Service Charges ("SSCs"), Late Payment Charges, Other Operating  
7 Revenue, and Other Income and Deductions.

8

9 Table 1 provides a summary of Other Revenue from 2016-2025, along with the associated  
10 Uniform System of Accounts ("USofA"). Table 1 has been both revised and updated, as detailed  
11 below. The revisions to 2016-2019 were made to remove some costs from Rate Base to  
12 non-distribution, resulting in an increase in Other Revenue. The revision to 2020 was made to  
13 include the offsetting entry to the regulatory asset for the Gains and Losses on Disposal of  
14 Fixed Assets Variance Account, as described in UPDATED Exhibit 9-1-3: Group 2 Accounts.  
15 The update in 2020-2022 was made as a result of the updated MiGen project, as described in  
16 the updates to section 2.3.3 of Attachment 2-4-3(E): Material Investments.



1 **Table 1 – AS ORIGINALLY SUBMITTED – Other Revenue Summary (\$'000s)**

Other Revenue	Historical Years			Bridge Years		Test Years				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Specific Service Charges (4235)	\$6,160	\$5,490	\$5,691	\$5,535	\$5,555	\$5,118	\$5,394	\$5,679	\$5,910	\$6,213
Late Payment Charges (4225)	\$1,029	\$1,072	\$1,041	\$1,126	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000
Other Operating Revenue (4082, 4084, 4086, 4090)	\$1,368	\$1,412	\$1,438	\$1,492	\$1,527	\$2,790	\$2,885	\$2,971	\$3,060	\$3,163
Other Income & Deductions (4315, 4325, 4330, 4362, 4375, 4405)	\$3,796	\$5,230	\$4,923	\$1,270	\$2,186	\$2,069	\$1,733	\$2,017	\$2,181	\$2,081
<b>TOTAL OTHER REVENUE<sup>1</sup></b>	<b>\$12,354</b>	<b>\$13,203</b>	<b>\$13,093</b>	<b>\$9,422</b>	<b>\$10,268</b>	<b>\$10,977</b>	<b>\$11,013</b>	<b>\$11,667</b>	<b>\$12,151</b>	<b>\$12,457</b>

2

3 **Table 1 – AS REVISED – Other Revenue Summary (\$'000s)**

Other Revenue	Historical Years			Bridge Years		Test Years				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Specific Service Charges (4235)	\$6,160	\$5,490	\$5,691	\$5,535	\$5,555	\$5,118	\$5,394	\$5,679	\$5,910	\$6,213
Late Payment Charges (4225)	\$1,029	\$1,072	\$1,041	\$1,126	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000
Other Operating Revenue (4082, 4084, 4086, 4090)	\$1,368	\$1,412	\$1,438	\$1,492	\$1,527	\$2,790	\$2,885	\$2,971	\$3,060	\$3,163
Other Income & Deductions (4315, 4325, 4330, 4362, 4375, 4405)	\$3,796	\$5,239	\$5,168	\$1,508	\$2,685	\$2,069	\$1,733	\$2,017	\$2,181	\$2,081
<b>TOTAL OTHER REVENUE<sup>2</sup></b>	<b>\$12,354</b>	<b>\$13,213</b>	<b>\$13,338</b>	<b>\$9,661</b>	<b>\$10,767</b>	<b>\$10,977</b>	<b>\$11,013</b>	<b>\$11,667</b>	<b>\$12,151</b>	<b>\$12,457</b>

4

5 <sup>1</sup> Totals may not sum due to rounding.

6 <sup>2</sup> Totals may not sum due to rounding. Note that the revision to 2016 Other Income and Deductions is immaterial

7 when rounded to thousands.





1 **Table 1 – UPDATED FOR 2019 ACTUALS – Other Revenue Summary (\$'000s)**

Other Revenue	Historical Years				Bridge Year	Test Years				
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Specific Service Charges (4235)	\$6,160	\$5,490	\$5,691	\$5,522	\$5,555	\$5,118	\$5,394	\$5,679	\$5,910	\$6,213
Late Payment Charges (4225)	\$1,029	\$1,072	\$1,041	\$994	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000
Other Operating Revenue (4082, 4084, 4086, 4090)	\$1,368	\$1,412	\$1,438	\$1,491	\$1,527	\$2,790	\$2,885	\$2,971	\$3,060	\$3,163
Other Income & Deductions (4315, 4325, 4330, 4362, 4375, 4405)	\$3,796	\$5,239	\$5,168	\$1,828	\$2,691	\$2,105	\$1,691	\$2,017	\$2,181	\$2,081
<b>TOTAL OTHER REVENUE<sup>3</sup></b>	<b>\$12,354</b>	<b>\$13,213</b>	<b>\$13,338</b>	<b>\$9,835</b>	<b>\$10,773</b>	<b>\$11,013</b>	<b>\$10,970</b>	<b>\$11,667</b>	<b>\$12,151</b>	<b>\$12,457</b>

2

3 A detailed breakdown of Other Operating Revenue and Other Income and Deductions is  
4 provided in **UPDATED** Attachment 3-2-1(A): OEB Appendix 2-H - Other Operating Revenue.

5

## 6 **2. SPECIFIC SERVICE CHARGES**

7 SSCs are applied for service requests or activities which primarily benefit or are attributed to the  
8 customer who requests or initiates the specific service or activity. An example would be setting  
9 up an account for a new customer. Conversely, some SSCs are applied as a result of a  
10 customer's inaction, such as non-payment. As part of this Application, Hydro Ottawa undertook  
11 a review of many routine service charges to ensure that the associated costs of providing such  
12 services were appropriately recovered.

13

### 14 **2.1. SUMMARY OF PROPOSED SSC CHANGES**

15 Changes to Hydro Ottawa's SSCs for the 2021-2025 period are discussed in more detail below.  
16 Additional information regarding SSCs can be found in **UPDATED** Exhibit 8-7-1: Specific  
17 Service Charges and Attachment 8-7-1(A): Proposed and New Specific Service Charge

<sup>3</sup> Totals may not sum due to rounding.



1 Calculations. Hydro Ottawa is proposing to apply its Custom Price Escalation Factor (“CPEF”) of  
2 2.51% to all SSCs for the years 2022-2025.<sup>4</sup> For detail and context on Hydro Ottawa’s CPEF,  
3 refer to **UPDATED** Exhibit 1-1-10: Alignment with the Renewed Regulatory Framework.

4

#### 5 **2.1.1. Removal of “Account Certificate” Charge**

6 The “Account Certificate” charge applies to the provision of both an Easement Certificate and an  
7 Arrears Certificate. The Easement Certificate confirms if Hydro Ottawa has any associated  
8 property easements, whereas the Arrears Certificate confirms if the current account has any  
9 outstanding payments. While historically, these two requests were routinely received for real  
10 estate transactions, over more recent years demand for the combined services has significantly  
11 declined. Additionally, the costs associated with the provision of each service have become  
12 distinctly different. Specifically, the Easement Certificate is now more labour intensive, relative to  
13 the Arrears Certificate. A separation of these related charges is therefore required to more  
14 accurately align the respective charge with associated costs.

15

16 Hydro Ottawa is requesting that the “Account Certificate” charge be eliminated and replaced  
17 with an “Easement Certificate for Unregistered Easements” charge to cover the costs of  
18 confirming unregistered easements and/or issuing compliance letters, per property search. The  
19 proposed charge would be set at \$25 in 2021 and escalated by Hydro Ottawa’s CPEF of 2.51%  
20 over the course of 2022-2025.

21

22 Similarly, Hydro Ottawa requests approval for an “Arrears Certificate” charge to cover the costs  
23 associated with confirming the payment status of an account, at the existing 2020 rate of \$15  
24 and escalated by 2.51% over the 2022-2025 period.

---

25 <sup>4</sup> The only exception to this approach is with respect to Dry Core Transformer Distribution Charges, which are based  
26 on proposed 2021-2025 distribution rates of the >50kW commercial classes, as well as the forecasted Regulated  
27 Price Plan, transmission, low voltage, and regulatory rates.



1 **2.1.2. Account Set Up/Change of Occupancy Charge**

2 A productivity initiative to streamline the customer move process reduced certain labour costs  
3 associated with opening and closing customer accounts. As a result, Hydro Ottawa is applying  
4 for a new rate of \$25 in 2021, which represents a \$5 reduction from the 2020 rate of \$30. Hydro  
5 Ottawa also proposes to apply its escalation factor of 2.51% annually between 2022 and 2025.

6

7 **2.1.3. Reconnect at Meter after Regular Hours**

8 During the previous rate period of 2016-2020, Hydro Ottawa phased-in remote meter  
9 reconnection technology in hard-to-access locations and premises that have high  
10 move-in/move-out trends. Through the use of Honeywell (formerly Elster) technology, Hydro  
11 Ottawa can remotely reconnect meters through its Advanced Metering Infrastructure ("AMI")  
12 equipped with the EnergyAxis Management System ("EA\_MS"). The operational productivity  
13 and efficiencies, including the elimination of a field trip to a customer's premise to reconnect  
14 electricity service, has reduced associated labour and fleet costs. Customers also benefit from  
15 more timely service restoration. As a result, Hydro Ottawa is applying for a new rate of \$100 in  
16 2021, which represents an \$85 reduction from the 2020 rate of \$185. Hydro Ottawa also  
17 proposes to apply its escalation factor of 2.51% annually between 2022 and 2025.

18

19 **2.1.4. Duplicate Invoices for Previous Billing**

20 The availability of online bills, presented in bill format, has enabled Hydro Ottawa to issue  
21 duplicate bills by email, rather than by Canada Post. This efficiency measure has resulted in  
22 both bill printing and mailing cost savings. Hydro Ottawa is seeking approval for a rate reduction  
23 from \$15 in 2020 to \$5 in 2021, along with its annual 2.51% escalation factor increase for the  
24 years 2022-2025. Requests for this service are forecast to remain static.

25

26 **2.1.5. Interval Meter - Field Reading**

27 This service charge initially included the costs associated with a Hydro Ottawa representative  
28 attending to the site of interval-metered customers to obtain a scheduled meter reading. Such



1 site visits would occur, within a reasonable timeframe, in situations in which the phone line was  
2 inoperable and the customer had not taken steps to have the phone line fixed.

3

4 More recently, Hydro Ottawa has partnered with a cellular carrier to provide a cellular modem  
5 that will eliminate the need for interval meter phone lines. As this initiative is being phased in,  
6 Hydro Ottawa may nevertheless need to continue visiting some interval-metered premises to  
7 take a meter reading, when the phone lines are inoperable. Where applicable, additional trips to  
8 the site to obtain manual readings will continue to be recovered.

9

10 The revenue associated with this service is expected to decline significantly as remote cellular  
11 communications are phased in. Hydro Ottawa is requesting approval to reduce the 2020 rate of  
12 \$378 to \$314 in 2021. An annual escalation of 2.51% for the years 2022-2025 is also sought.

13

#### 14 **2.1.6. Unprocessed Payment Charge**

15 This service charge recovers internal costs associated with unprocessable payments.  
16 Historically, Hydro Ottawa has been applying the standard 2006 Electricity Distribution Rate  
17 ("EDR") handbook rate. However, a recent internal costing review revealed there was a material  
18 shortfall in actual cost recovery. As a result, Hydro Ottawa is seeking approval for an increase  
19 from \$15 to \$25 in 2021. The utility is proposing to apply its escalation factor of 2.51% annually  
20 for the years 2022-2025.

21

#### 22 **2.1.7. Reconnect at Pole - During Regular Hours**

23 This service charge relates to service reconnections that must be conducted at the distribution  
24 pole by qualified lines persons. Historically, Hydro Ottawa has been applying the standard 2006  
25 EDR handbook rate. However, a recent internal costing review revealed there was a material  
26 shortfall in actual cost recovery. As a result, Hydro Ottawa is seeking approval for an increase  
27 from \$185 in 2020 to \$250 in 2021. The utility also proposes to apply its escalation factor  
28 increase of 2.51% annually between 2022 and 2025.



1 **2.1.8. Special Billing Service**

2 This SSC recovers the costs (primarily labour) associated with the provision of additional billing  
3 services that require sourcing, compiling, and presenting several months or years of billing  
4 information for customers or their agents. Hydro Ottawa is seeking approval for an increase  
5 from \$104 in 2020 to \$122 in 2021 and its escalation factor increase of 2.51% per year  
6 between 2022 and 2025.

7

8 **2.1.9. Specific Charge to Access Power Poles - Wireline**

9 For the 2016-2020 period, Hydro Ottawa secured approval from the OEB for a utility-specific  
10 rate of \$53 per pole per year. For the 2021 Test Year, Hydro Ottawa intends to move to the  
11 OEB's generic rate of \$45.39, consistent with the policy established by the OEB in 2018.<sup>5</sup> The  
12 OEB's approved 2020 inflationary factor has been used to increase the provincially approved  
13 rate for 2021, and an escalation factor increase of 2.51% per year between 2022 and 2025.

14

15 **2.1.10. Dry Core Transformer Charge**

16 On an annual basis, these charges are updated to reflect the new Regulated Price Plan ("RPP")  
17 prices, transmission rates, and Hydro Ottawa's distribution rates. Please see **UPDATED** Exhibit  
18 8-7-1: Specific Service Charges and **UPDATED** Attachment 8-7-1(B): Dry Core Calculations for  
19 more information. The distribution portion of the revenues for 2021-2025 are based on  
20 estimated bill impacts of the commercial customers that are charged for dry core transformers.

21

22 **2.2. HIGH LEVEL SSC VARIANCE ANALYSIS**

23 **2.2.1. 2016 Actual to 2017 Actual**

24 SSC revenues for 2017 were \$700K (11%) below 2016 actuals. The main driver was a one-time  
25 \$549K recognition of miscellaneous revenue in 2016. A contingent liability was booked in  
26 relation to a customer payment received prior to a bankruptcy proceeding. This liability was  
27 reversed once the provision recognition criteria no longer applied. Further, the introduction of

---

<sup>5</sup> Ontario Energy Board, *Report of the Ontario Energy Board - Wireline Pole Attachment Charge*, EB-2015-0304 (March 22, 2018).



1 the Disconnection Moratorium for residential customers in 2017 reduced the overall volume of  
2 reconnection activity – and by extension, revenues – in 2017 by approximately \$130K.

3

#### 4 **2.2.2. 2017 Actual to 2018 Actual**

5 SSC revenues in 2018 were \$221K (4%) above 2017 actuals. This increase was primarily due  
6 to an increase in Collection of Account revenue of \$134K (27.8%) and Pole Attachment revenue  
7 of \$121K (3.6%), due to higher than historical field collection activity and a higher than  
8 forecasted increase in actual pole attachments.

9

#### 10 **2.2.3. 2018 Actual to 2019 Bridge Year**

11 SSC revenues for 2019 are forecasted to be \$157K (3%) below 2018 actuals. The main driver is  
12 the removal of the Collection of Account Charge for residential customers, effective July 1,  
13 2019, in compliance with the Phase 1 amendments to the OEB's Customer Service Rules.<sup>6</sup>

14

#### 15 **2018 Actual to 2019 Actual**

16 SSC revenues in 2019 were \$170K (3%) below 2018 actuals. The main driver is the removal of  
17 the Collection of Account Charge for residential customers, effective July 1, 2019, in compliance  
18 with the Phase 1 amendments to the OEB's Customer Service Rules.

19

#### 20 **2.2.4. 2019 Bridge Year to 2020 Bridge Year**

21 SSC revenues for 2020 are forecasted to be \$21K (0.3%) above the 2019 forecast. There are  
22 no variances of material value to note. Modest revenues from wireless pole attachments are  
23 forecasted in 2020.

24

#### 25 **2019 Actual to 2020 Bridge Year**

26 SSC revenues for 2020 are forecasted to be \$34K (0.6%) above the 2019 actuals.

---

27 <sup>6</sup> Ontario Energy Board, *Notice of Amendments to Codes and a Rule: Amendments to the Distribution System Code,*  
28 *Standard Supply Service Code, Unit Sub-metering Code, and Gas Distribution Access Rule (and Associated Rate*  
29 *Order)*, EB-2017-0183 (March 14, 2019).



1 **2.2.5. 2020 Bridge Year to 2021 Test Year**

2 SSC revenues in 2021 are forecasted to be \$0.5M (8%) below the 2020 forecast. The reasons  
3 for this reduction are noted in section 2.1 above. The annual increase from 2021-2025 is  
4 primarily due to the escalation factor applied to the rates each year. One exception is wireless  
5 pole attachments, where volumes are expected to increase by 200 units on an annual basis out  
6 to 2025.

7

8 **2.3. SSC FORECAST AND VARIANCE ANALYSIS**

9 Each SCC is forecasted based on the rate factored by the estimated volume. Tables 2 and 3  
10 below provide the revenue actuals and forecast for each SSC. Table 2 has been updated to  
11 account for 2019 actuals.

12

13 Thereafter, Hydro Ottawa provides an analysis for each SCC of the difference in revenues that  
14 are expected between the 2016-2020 and 2021-2025 rate periods.



1 **Table 2 – AS ORIGINALLY SUBMITTED – Specific Service Charge Revenue 2016-2020**  
2 **(\$'000s)**

Specific Service Charge Revenue	Historical Years			Bridge Years	
	2016	2017	2018	2019	2020
<b>Customer Administration</b>					
Account Certificate	\$4	\$3	\$2	\$4	\$2
Easement Certificate for Unregistered Easements	\$0	\$0	\$0	\$0	\$0
Duplicate invoices for previous billing	\$3	\$2	\$3	\$2	\$3
Special Billing Service	\$4	\$4	\$6	\$5	\$5
Credit Reference/Credit Check (+ credit agency costs)	\$0	\$2	\$1	\$1	\$1
Unprocessed Payment Charge	\$36	\$33	\$32	\$33	\$30
Account Set Up Charge / Change of Occupancy Charge	\$1,870	\$1,775	\$1,696	\$1,733	\$1,696
<b>Reconnect at Meter</b>					
<i>Regular Hours</i>	\$15	\$5	\$4	\$6	\$4
<i>After Regular Hours</i>	\$5	\$1	\$0	\$2	\$1
Interval Meter - Field Reading	\$1	\$1	\$32	\$5	\$2
High Bill Investigation - If Billing is Correct	\$3	\$3	\$1	\$2	\$2
<b>Non-Payment of Account</b>					
Collection of Account Charge - No Disconnection	\$11	\$5	\$139	\$69	\$0
<b>Reconnect at Meter</b>					
<i>Regular Hours</i>	\$237	\$170	\$154	\$145	\$154
<i>After Regular Hours</i>	\$162	\$113	\$125	\$84	\$111
<b>Reconnect at Pole</b>					
<i>Regular Hours</i>	\$3	\$3	\$3	\$3	\$3
<i>After Regular Hours</i>	\$1	\$1	\$1	\$0	\$1
<b>Other</b>					
<b>Temporary Service - Install and Remove</b>					
<i>Overhead - no transformer</i>	\$5	\$11	\$8	\$12	\$11
<i>Underground - no transformer</i>	\$6	\$24	\$25	\$25	\$25
<i>Overhead - with transformer</i>	\$6	\$12	\$9	\$6	\$9
<b>Specific Access to Power Poles</b>					
<i>Wireline Pole Attachments</i>	\$3,218	\$3,296	\$3,417	\$3,356	\$3,415
<i>Wireless Pole Attachments</i>	\$0	\$0	\$0	\$0	\$34
Drycore Transformer Distribution Charge	\$23	\$27	\$32	\$42	\$46
Energy Resource Facilities Charge	\$0	\$0	\$0	\$0	\$0
<b>TOTAL<sup>7</sup></b>	<b>\$6,160</b>	<b>\$5,490</b>	<b>\$5,691</b>	<b>\$5,535</b>	<b>\$5,555</b>

3

4 <sup>7</sup> Totals may not sum due to rounding.





1 **Table 2 – UPDATED FOR 2019 ACTUALS – Specific Service Charge Revenue 2016-2020**  
2 **(\$'000s)**

Specific Service Charge Revenue	Historical Years				Bridge Years
	2016	2017	2018	2019	2020
<b>Customer Administration</b>					
Account Certificate	\$4	\$3	\$2	\$6	\$2
Easement Certificate for Unregistered Easements	\$0	\$0	\$0	\$0	\$0
Duplicate invoices for previous billing	\$3	\$2	\$3	\$2	\$3
Special Billing Service	\$4	\$4	\$6	\$9	\$5
Credit Reference/Credit Check (+ credit agency costs)	\$0	\$2	\$1	\$2	\$1
Unprocessed Payment Charge	\$36	\$33	\$32	\$38	\$30
Account Set Up Charge / Change of Occupancy Charge	\$1,870	\$1,775	\$1,696	\$1,690	\$1,696
<b>Reconnect at Meter</b>					
Regular Hours	\$15	\$5	\$4	\$3	\$4
After Regular Hours	\$5	\$1	\$0	\$1	\$1
Interval Meter - Field Reading	\$1	\$1	\$32	\$5	\$2
High Bill Investigation - If Billing is Correct	\$3	\$3	\$1	\$2	\$2
<b>Non-Payment of Account</b>					
Collection of Account Charge - No Disconnection	\$11	\$5	\$139	\$18	\$0
<b>Reconnect at Meter</b>					
Regular Hours	\$237	\$170	\$154	\$176	\$154
After Regular Hours	\$162	\$113	\$125	\$42	\$111
<b>Reconnect at Pole</b>					
Regular Hours	\$3	\$3	\$3	\$3	\$3
After Regular Hours	\$1	\$1	\$1	\$0	\$1
<b>Other</b>					
<b>Temporary Service - Install and Remove</b>					
Overhead - no transformer	\$5	\$11	\$8	\$10	\$11
Underground - no transformer	\$6	\$24	\$25	\$34	\$25
Overhead - with transformer	\$6	\$12	\$9	\$9	\$9
<b>Specific Access to Power Poles</b>					
Wireline Pole Attachments	\$3,218	\$3,296	\$3,417	\$3,432	\$3,415
Wireless Pole Attachments	\$0	\$0	\$0	\$0	\$34
Drycore Transformer Distribution Charge	\$23	\$27	\$32	\$39	\$46
Energy Resource Facilities Charge	\$0	\$0	\$0	\$0	\$0
<b>TOTAL<sup>8</sup></b>	<b>\$6,160</b>	<b>\$5,490</b>	<b>\$5,691</b>	<b>\$5,522</b>	<b>\$5,555</b>

3 <sup>8</sup> Totals may not sum due to rounding.



1 **Table 3 – Specific Service Charge Revenue 2021-2025 (\$'000s)**

Specific Service Charge Revenue	Test Years				
	2021	2022	2023	2024	2025
<b>Customer Administration</b>					
Arrears Certificate (formerly Account Certificate)	\$0	\$0	\$0	\$0	\$0
Easement Certificate for Unregistered Easements	\$8	\$8	\$8	\$8	\$8
Duplicate invoices for previous billing	\$1	\$1	\$1	\$1	\$1
Special Billing Service	\$6	\$6	\$6	\$7	\$7
Credit Reference/Credit Check (+ credit agency costs)	\$2	\$3	\$3	\$3	\$3
Unprocessed Payment Charge	\$50	\$52	\$54	\$54	\$56
Account Set Up Charge / Change of Occupancy Charge	\$1,413	\$1,470	\$1,526	\$1,526	\$1,583
<b>Reconnect at Meter</b>					
<i>Regular Hours</i>	\$4	\$4	\$4	\$4	\$4
<i>After Regular Hours</i>	\$0	\$0	\$0	\$0	\$0
Interval Meter - Field Reading	\$1	\$1	\$1	\$1	\$1
High Bill Investigation - If Billing is Correct	\$2	\$2	\$3	\$3	\$3
<b>Non-Payment of Account</b>					
Collection of Account Charge - No Disconnection	\$0	\$0	\$0	\$0	\$0
<b>Reconnect at Meter</b>					
<i>Regular Hours</i>	\$159	\$164	\$168	\$171	\$176
<i>After Regular Hours</i>	\$60	\$62	\$64	\$65	\$67
<b>Reconnect at Pole</b>					
<i>Regular Hours</i>	\$4	\$4	\$4	\$5	\$5
<i>After Regular Hours</i>	\$1	\$1	\$1	\$1	\$1
<b>Other</b>					
<b>Temporary Service - Install and Remove</b>					
<i>Overhead - no transformer</i>	\$12	\$12	\$12	\$12	\$13
<i>Underground - no transformer</i>	\$26	\$26	\$27	\$28	\$28
<i>Overhead - with transformer</i>	\$9	\$10	\$10	\$10	\$10
<b>Specific Access to Power Poles</b>					
<i>Wireline Pole Attachments</i>	\$3,240	\$3,373	\$3,512	\$3,657	\$3,808
<i>Wireless Pole Attachments</i>	\$69	\$142	\$217	\$295	\$376
Drycore Transformer Distribution Charge	\$49	\$53	\$56	\$59	\$63
Energy Resource Facilities Charge	\$0	\$0	\$0	\$0	\$0
<b>TOTAL<sup>9</sup></b>	<b>\$5,118</b>	<b>\$5,394</b>	<b>\$5,679</b>	<b>\$5,910</b>	<b>\$6,213</b>

2 <sup>9</sup> Totals may not sum due to rounding.

1 **2.3.1. Arrears Certificate**

2 For the Arrears Certificate (formerly Account Certificate), Hydro Ottawa will continue to use the  
3 standard provincial rate for 2020 and increase by its escalation factor of 2.51% per year starting  
4 in 2021 through 2025.

5

6 **Variance analysis:**

7 Future demand for this service is expected to be lower than Historical Years, partially due to the  
8 separation of the Easement Certificate for Unregistered Easements charge, as noted in 2.3.2  
9 below. Therefore, the volume and estimated revenue is set at zero. Hydro Ottawa wishes to  
10 maintain this charge in the event that customers should require this service.

11

12 **2.3.2. Easement Certificate for Unregistered Easements**

13 Hydro Ottawa is proposing to introduce a new charge for Easement Certificate for Unregistered  
14 Easements, which was previously embedded in the Account Certificate Charge.

15

16 **Variance analysis:**

17 Most historical revenues were associated with this service. A new rate of \$25 is proposed for  
18 2021 and will be increased annually by 2.51% per year through to 2025. This rate is reflective of  
19 the cost to offer this service. The estimated revenue is based upon a volume of 320 requests  
20 per year.

21

22 **2.3.3. Duplicate Invoices for Previous Billing**

23 Hydro Ottawa is proposing to reduce the current 2020 rate of \$15 to \$5 in 2021 and adjust the  
24 rate annually by 2.51% through to 2025. Further automation of this service provision has  
25 reduced costs and, hence, the rate. The forecasted volume is based upon historical trends,  
26 which are modest at 170 requests per year.



1 **Variance analysis:**

2 There are no material differences in actual versus budgeted revenues for the 2016-2018 period  
3 or in the year-over-year revenue forecast from 2016-2025. The lower revenue forecast, as of  
4 2021, reflects the proposed reduced rate.

5

6 **2.3.4. Special Billing Service**

7 The Special Billing Service charge (formerly Request for other Billing Information) was  
8 introduced as part of Hydro Ottawa's 2016-2020 rate application.<sup>10</sup> It was applied to all requests  
9 for customized billing information that involves sourcing, compiling, and presenting several  
10 months or years of billing information for customers or their agents. Hydro Ottawa is proposing a  
11 rate of \$122 in 2021 and making an annual adjustment of 2.51% through to 2025. This rate  
12 reflects the Hydro Ottawa labour rate for this labour-intensive service. The volume estimated is  
13 expected to remain similar to the 2016-2020 period.

14

15 **Variance analysis:**

16 There are no material revenue differences in actual versus budgeted revenues during the  
17 2016-2018 period or year-over-year during the 2016-2025 period.

18

19 **2.3.5. Credit Reference/Credit Check**

20 Hydro Ottawa will continue to apply the standard provincial rate of \$15 for 2020 and adjust  
21 annually in accordance with its escalation factor, beginning in 2021 through 2025. The volume  
22 estimate will continue to be based on historical trends with a forecast of 66 per year. This is in  
23 line with the 2016-2018 actual volumes.

24

25 **Variance analysis:**

26 There are no material differences in actual versus budgeted revenues for the 2016-2018 period,  
27 or in the year-over-year revenue forecast over the 2016-2025 period.

---

28 <sup>10</sup> Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-setting Distribution Rate Application*, EB-2015-0004  
29 (April 29, 2015).



1 **2.3.6. Unprocessed Payment Charge**

2 Hydro Ottawa is proposing to increase the current 2020 rate of \$15 to \$25 in 2021 and apply its  
3 escalation factor of 2.51% annually through to 2025. The proposed rate increase is based upon  
4 internal costing analysis which determined insufficient cost recovery for this service. Costs  
5 associated with this service include internal costs for administering an unprocessable payment  
6 (i.e. non-sufficient funds or "NSF"), labour, and bank fees. Annual volume estimates for the  
7 2021-2025 rate period are estimated to be 2,000. The increase in revenue between 2021 and  
8 2025 reflects the proposed, revised service charge.

9

10 **Variance analysis:**

11 There were no material differences in actual versus budgeted revenue for the 2016-2018 period  
12 or in year-over-year for the 2016-2025 period. The increase in revenue forecast, as of 2021, is a  
13 reflection of the new proposed rate.

14

15 **2.3.7. Account Set Up Charge/Change of Occupancy Charge**

16 Hydro Ottawa is proposing to reduce the current 2020 rate of \$30 to \$25 in 2021 and increase  
17 by 2.51% annually through to 2025. The proposed new rate reflects labour savings due to a  
18 streamlined customer Move-In/Move-Out process, which enables the Contact Centre to  
19 complete 50% of customer moves. The volume estimate for the last rate application estimated  
20 1% growth per year. Actual volumes from 2016-2020 have averaged 56,500 moves on an  
21 annual basis. Therefore, the 2018 actual volume has been applied from 2021-2025.

22

23 **Variance analysis:**

24 Hydro Ottawa is trending below budget from 2016-2018 by \$122K, \$237K, and \$336K,  
25 respectively. While the budget assumed 1% growth in account setup revenue year-over-year,  
26 actuals are showing a decline of about 5% from 2016 to 2017 and 4% from 2017 to 2018. The  
27 associated reduction in forecasted revenue through 2025, as of 2021, reflects the reduced  
28 service charge rate.



1 **2.3.8. Interval Meter - Field Reading**

2 Hydro Ottawa is proposing to reduce the current 2020 rate of \$378 to \$314 in 2021 and apply its  
3 annual escalation factor of 2.51% through to 2025. The main driver of the reduced rate is to  
4 align this business practice with other field practices, which provides a Hydro Ottawa  
5 representative field visit once without charge. As such, Hydro Ottawa is no longer proposing to  
6 include the cost of an initial visit to obtain an interval meter field reading. The volume estimate is  
7 based on recent annual trends.

8

9 **Variance analysis:**

10 There are no material revenue differences year-over-year for the 2016-2025 period.

11

12 **2.3.9. High Bill Investigation - If Billing is Correct**

13 Hydro Ottawa proposes to continue with the 2020 utility-specific rate and adjust by its annual  
14 escalation factor of 2.51% between 2021 to 2025. The forecasted volume has been reduced to  
15 align with recent trending.

16

17 **Variance analysis:**

18 There are no material revenue differences year-over-year for the 2016-2025 period.

19

20 **2.3.10. Collection of Account Charge**

21 This charge was removed, effective July 1, 2019, in accordance with the implementation of  
22 Phase 1 of the OEB's Customer Service Rules.

23

24 **Variance analysis:**

25 Actual revenues exceeded budget in 2018 due to increased use of this charge to offset some of  
26 the costs associated with rolling a truck to hand deliver a 48-hour warning notice, in advance of  
27 disconnection action. In 2019, Hydro Ottawa implemented an automated notification solution as  
28 the primary option for communication of the 48-hour disconnection notice. As a result, the  
29 revenue forecast for 2019 and 2020 has been reduced to reflect the lower than historical

1 premise visits associated with providing a 48-hour warning notice to customers scheduled to be  
2 disconnected for non-payment.

3

#### 4 **2.3.11. Reconnect at Meter during Regular Hours**

5 Hydro Ottawa shall continue to apply the standard provincial rate for 2020 and apply its annual  
6 escalation factor of 2.51% for the 2021-2025 period. The increasing availability of automated  
7 meter reconnections has reduced internal costs and has therefore allowed full cost recovery  
8 within the current rate. The estimated volumes for 2021-2025 are based upon 2018 actuals.

9

#### 10 **Variance analysis:**

11 Hydro Ottawa trended below budget in 2017 and 2018. This is primarily due to the  
12 Disconnection Moratorium, which is effective annually from November 15th to April 30th.

13

#### 14 **2.3.12. Reconnect at Meter after Regular Hours**

15 Hydro Ottawa is proposing to reduce the current 2020 rate of \$185 to \$100 in 2021 and apply its  
16 annual escalation factor of 2.51% through to 2025. Based upon 2017 and 2018 actual volumes,  
17 the volume estimates for 2021-2025 are slightly lower than the historical forecast.

18

#### 19 **Variance analysis:**

20 There are no material differences in actual versus budgeted revenues for the 2016-2018 period  
21 or in year-over-year for the 2016-2025 period. The reduced revenue forecast as of 2021 reflects  
22 the reduced charge.

23

#### 24 **2.3.13. Reconnect at Pole during Regular Hours**

25 Hydro Ottawa is proposing to increase the current 2020 rate of \$185 to \$250 in 2021 and apply  
26 its 2.51% escalation factor each year for the 2022-2025 period. An increase in this charge is  
27 sought to recover associated labour and fleet costs. Reconnection at the pole is more costly,  
28 because two specially-qualified employees are required due to the increased safety  
29 requirements of pole work. While the volume was estimated at zero for the previous rate



1 application, based upon more recent trending a volume of 17 per year is estimated for the  
2 2021-2025 rate term.

3

4 **Variance analysis:**

5 Actual volume exceeded the zero forecast. There are no material differences in actual versus  
6 budgeted revenues for the 2016-2018 period or in year-over-year for the 2016-2025 period.

7

8 **2.3.14. Reconnect at Pole after Regular Hours**

9 Hydro Ottawa will continue to adopt the standard provincial rate for 2020 and increase by the  
10 annual escalation factor between 2021 and 2025. The volume estimate has been increased to  
11 two per year for the 2021-2025 period, based upon recent trending.

12

13 **Variance analysis:**

14 Actuals were greater than forecast as these types of reconnections are relatively infrequent. As  
15 such, a volume of zero was estimated for the period 2016-2020. The small volume reflects  
16 actual revenue. There are no material revenue differences in actual versus budgeted for the  
17 2016-2018 period or in year-over-year for the 2016-2025 period.

18

19 **2.3.15. Temporary Service - Install & Remove**

20 Temporary services cover the connection, metering, installation, and removal of required assets  
21 to supply electrical energy on a planned temporary basis, as per Hydro Ottawa's Conditions of  
22 Service. Transformer rental costs are included in the Temporary Service - Install & Remove -  
23 Overhead - with transformer charge. Any additional material costs beyond the standard service,  
24 such as the installation of a pole, the upgrade of a secondary buss, or new underground  
25 transformer requirements will be charged in addition to this SSC and will be recorded as Other  
26 Income and Deductions.





1 Hydro Ottawa plans to continue with the 2020 utility-specific rates and increase them by its  
2 annual escalation factor of 2.51% starting in 2021 through 2025. The volume estimate has been  
3 based on the actual 2016-2018 values.

4

5 **Variance analysis:**

6 There are no material year-over-year revenue variances for the 2016-2025 period.

7

8 **2.3.16. Specific Access to Power Poles - Wireline Attachments**

9 Hydro Ottawa generates joint use revenue from third parties who place attachments on the  
10 utility's poles. There are currently pole attachment agreements with 11 telecommunication  
11 companies, and agreements with the City of Ottawa and Village of Casselman for streetlight  
12 attachments. Hydro Ottawa has seen modest increases in the number of pole attachments from  
13 2016-2020. This historical trend is the basis for the 2021-2025 forecasted volume. As of 2021,  
14 Hydro Ottawa will be moving from the utility-specific wireline pole attachment rate of \$53.00 per  
15 pole per year to the provincially approved rate of \$43.63. The generic provincial rate is adjusted  
16 on January 1st each year, based upon the OEB-approved inflation factor. Please refer to Exhibit  
17 8-7-1: Specific Service Charges for complete details on the updated rate.

18

19 **Variance analysis:**

20 Revenues in 2021 are forecasted to drop approximately \$175K over the 2020 forecast.

21 Between 2022 and 2025, revenues are expected to increase modestly.

22

23 **2.3.17. Specific Access to Power Poles - Wireless Attachments**

24 Hydro Ottawa currently has very few wireless pole attachment agreements. Revenues are only  
25 expected to commence in 2020. In 2021, Hydro Ottawa intends to close the Deferral and  
26 Variance Account established as part of the 2016-2020 rate application to record wireless pole  
27 attachment revenue, as it is anticipated that revenue from this source can reasonably be  
28 forecasted in the future. Please see Exhibit 9-1-3: Group 2 Accounts for further information.



1 Future volume and revenues for wireless attachments have been based on estimates. Please  
2 refer to Exhibit 8-7-1: Specific Service Charges for complete details on the wireless pole  
3 attachment rate.

4

5 **Variance analysis:**

6 Revenues between 2020 and 2025 are expected to increase modestly.

7

8 **2.3.18. Dry Core Transformer Charges**

9 Dry Core transformer charges are applied to recover energy lost in the operation of dry core  
10 transformers. A specific charge is calculated for each transformer size.

11

12 Hydro Ottawa is proposing to include rates for new sizes of transformers that are currently in the  
13 utility's service area, as well as sizes in CSA-C802-94 that were not previously included in the  
14 Schedule of Rates and Tariffs. In addition, Hydro Ottawa is proposing to calculate the dry core  
15 transformer loss charge for any new size of transformer upon connection, based on the  
16 approved dry core rate design. Hydro Ottawa proposes to add new dry core transformers to the  
17 Schedule of Rates and Tariffs on an annual basis as part of the utility's annual rate adjustment  
18 applications during the 2021-2025 period. Please see **UPDATED** Exhibit 8-7-1: Specific Service  
19 Charges for further details on the Dry Core transformer charges.

20

21 **Variance analysis:**

22 There are no material year-over-year revenue variances for the 2016-2025 period. Hydro  
23 Ottawa has used historical trending to estimate the revenue for 2021-2025.

24

25 **2.3.19. Miscellaneous Revenue**

26 There was a one-time \$549K recognition of miscellaneous revenue in 2016. This contingent  
27 liability was reversed as the provision recognition criteria were no longer applicable.



1 **3. LATE PAYMENT CHARGES**

2 An OEB-approved monthly interest rate of 1.5% (effective annual rate of 19.56% per annum or  
3 0.04896% compounded daily rate) is applied to outstanding account balances that exceed 16  
4 calendar days from the date on which the bill was issued to the customer. Effective March 1,  
5 2020, the minimum payment period will be extended to 20 calendar days, in accordance with  
6 Phase 1 of the OEB's Review of Customer Service Rules.

7

8 A decline in Late Payment Charge revenue is forecasted, taking into account the continued  
9 promotion of automated payment withdrawal services, effective use of the Auto Dialer tool  
10 during the Disconnection Moratorium timeframe, and additional proposed OEB Customer  
11 Service Rule changes.<sup>11</sup> As originally submitted, Late Payment Charge revenue is expected to  
12 decline to \$1.0M for the years 2020-2025. After accounting for 2019 actuals, Late Payment  
13 Charge revenue is expected to remain flat at \$1.0M for the years 2020-2025.

14

15 **4. OTHER OPERATING REVENUES**

16 Other Operating Revenues include revenue associated from the provision of Standard Supply,  
17 Retailer, and Generator services. Tables 4 and 5 show Historical Year (2016-2018), Bridge Year  
18 (2019-2020), and Test Year (2021-2025) revenue for Other Operating Revenues. Table 4 has  
19 been updated to account for 2019 actuals, and shows Historical Years (2016-2019) and Bridge  
20 Year (2020) revenue for Other Operating Revenues. Table 5 remains unchanged and displays  
21 revenue for Other Operating Revenues for the 2021-2025 Test Years.

22 <sup>11</sup> Ontario Energy Board, Letter re: *Review of Customer Service Rules for Electricity and Gas (Phase 2)*,  
23 EB-2017-0183 (October 25, 2018).



1 **Table 4 – AS ORIGINALLY SUBMITTED – Other Operating Revenue 2016-2020 (\$'000s)**

Other Operating Revenue	Historical Years			Bridge Years	
	2016	2017	2018	2019	2020
Standard Supply Administration	\$951	\$960	\$973	\$958	\$936
Retailer Services	\$160	\$135	\$122	\$157	\$188
Generator Services	\$257	\$316	\$342	\$378	\$403
<b>TOTAL <sup>12</sup></b>	<b>\$1,368</b>	<b>\$1,412</b>	<b>\$1,438</b>	<b>\$1,492</b>	<b>\$1,527</b>

2

3 **Table 4 – UPDATED FOR 2019 ACTUALS – Other Operating Revenue 2016-2020 (\$'000s)**

Other Operating Revenue	Historical Years				Bridge Years
	2016	2017	2018	2019	2020
Standard Supply Administration	\$951	\$960	\$973	\$996	\$936
Retailer Services	\$160	\$135	\$122	\$108	\$188
Generator Services	\$257	\$316	\$342	\$387	\$403
<b>TOTAL <sup>13</sup></b>	<b>\$1,368</b>	<b>\$1,412</b>	<b>\$1,438</b>	<b>\$1,491</b>	<b>\$1,527</b>

4

5 **Table 5 – Other Operating Revenue 2021-2025 (\$'000s)**

Other Operating Revenue	Test Years				
	2021	2022	2023	2024	2025
Standard Supply Administration	\$2,346	\$2,444	\$2,543	\$2,642	\$2,742
Retailer Services	\$165	\$148	\$133	\$119	\$107
Generator Services	\$279	\$293	\$296	\$299	\$314
<b>TOTAL <sup>14</sup></b>	<b>\$2,790</b>	<b>\$2,885</b>	<b>\$2,971</b>	<b>\$3,060</b>	<b>\$3,163</b>

6

7 **4.1. STANDARD SUPPLY SERVICE ADMINISTRATION CHARGE**

8 The Standard Supply Service Administration Charge (“SSS Charge”) is an administrative charge  
9 that allows Hydro Ottawa to recover its costs of providing standard supply service to all

<sup>12</sup> Totals may not sum due to rounding.

<sup>13</sup> Totals may not sum due to rounding.

<sup>14</sup> Totals may not sum due to rounding.



1 customers who are not enrolled with a Retailer. The SSS Charge was introduced on May 11,  
2 2005 as part of the 2006 EDR.<sup>15</sup>

3

4 The monthly SSS Charge of \$0.25 per customer per month has not been adjusted to reflect  
5 actual costs or inflation since implementation. In light of the OEB's review of miscellaneous  
6 service charges, as announced on November 5, 2015, it is anticipated that this rate will be  
7 updated.<sup>16</sup> Until such time, Hydro Ottawa is proposing to increase the SSS Charge to align with  
8 the 2021-2025 Retailer Services, Distributor-Consolidated Billing monthly charge. The  
9 corresponding increase will result in customers paying an equal service charge regardless of  
10 electricity service provider, and the pricing between Hydro Ottawa and the Retailer will be  
11 relatively maintained.

12

13 This approach will also ensure that Hydro Ottawa will not lose revenue regardless of what  
14 supply choice the customer makes. Please refer to **UPDATED** Exhibit 8-7-1: Specific Service  
15 Charges for further details on the SSS Charge rate design.

16

#### 17 **Variance analysis:**

18 Overall net customer growth has resulted in slightly higher revenue than forecasted. In addition,  
19 a lower number of retail customers than anticipated has increased the number of customers  
20 being charged the SSS Charge, as opposed to Hydro Ottawa collecting customer-related  
21 charges from Retailers. As a result, a similar decrease in revenue has occurred related to  
22 Retailer Service Charges. The net impact of these two variances has resulted in an average of  
23 \$44.2K higher revenues related to the SSS Charge on a yearly basis during the 2016-2018  
24 period. This trend continued in 2019.

25

#### 26 **4.2. RETAILER SERVICES**

27 Retailer Service Charges ("RSCs") recover the costs of services that Hydro Ottawa provides to  
28 electricity retailers, or their customers, in relation to the competitive supply of energy. The

---

<sup>15</sup> Ontario Energy Board, *2006 Electricity Distribution Rate Handbook* (May 11, 2005), page 126.

<sup>16</sup> Ontario Energy Board, Letter re: *Review of Miscellaneous Rates and Charges*, EB-2015-0304 (November 5, 2015).



1 revenue generated from the RSCs have declined annually due to a reduction in the number of  
2 customers enrolled with a Retailer. Notwithstanding the decrease in retailer-enrolled customers,  
3 Hydro Ottawa's expenses related to these services have remained constant.

4

5 Hydro Ottawa intends to apply the OEB generic rates for RSCs. Please see Exhibit 8-4-1: Retail  
6 Service Charges for more information on the 2021-2025 RSCs.

7

8 **Variance analysis:**

9 RSCs are mainly driven by the number of customers who are enrolled with a retailer. As the  
10 number of retail customers has been lower than that which was estimated in the utility's  
11 2016-2020 rate application, less revenue has been collected. On average, \$40.2K less revenue  
12 has been collected per year over the 2016-2018 period.

13

14 **4.3. GENERATOR SERVICES**

15 Monthly fixed charges for generation customers, other than the microFIT charge, were  
16 introduced in Hydro Ottawa's 2016-2021 rate application to reflect the cost of managing these  
17 accounts. The microFIT charge was requested to be a utility-specific charge in order to reflect  
18 the cost of managing related accounts. Hydro Ottawa has reviewed these charges and is  
19 proposing to update and continue using them for the 2021-2025 period.

20

21 As a result of greater efficiencies in managing an increasing number of generators, Hydro  
22 Ottawa is proposing to reduce the current 2020 monthly rate of \$19 for microFit and Net  
23 Metering customers to \$14 in 2021, and the current 2020 monthly rate of \$129 for FIT  
24 customers to \$76 in 2021.

25

26 Hydro Ottawa proposes an increase to the rate for managing a small number of larger  
27 generators from the 2020 rate of \$281 to \$314 in 2021.



1 Hydro Ottawa proposes to increase the generation charges annually by 2.51% for 2022-2025.  
2 This rate is consistent with the escalation rate applied to Hydro Ottawa's 2022-2025 operations,  
3 maintenance and administration ("OM&A") expenses and the majority of other revenue rates as  
4 part of this Application. For more details regarding the utility's proposed custom escalation rate  
5 for its 2021-2025 rate term, please see **UPDATED** Exhibit 1-1-10: Alignment with the Renewed  
6 Regulatory Framework.

7

8 For complete details on the design of generation charges, please refer to **UPDATED** Exhibit  
9 8-7-1: Specific Service Charges.

10

#### 11 **Variance Analysis:**

12 Fewer than expected generator contracts within Hydro Ottawa's service territory have come to  
13 fruition. By extension, the number of generator connections has been lower than anticipated.  
14 However, over the three-year period from 2016-2018 there is no material variance in revenue  
15 from generation charges.

16

#### 17 **5. OTHER INCOME AND DEDUCTIONS**

18 A fourth and final way in which Hydro Ottawa earns revenue is through the provision of services  
19 to customers and third parties, property rental income from leased plant, gains (or losses) on  
20 the disposal or retirement of utility property, the provision of services to Hydro Ottawa's affiliates,  
21 and earning interest income on short-term investments.

22

23 These activities are classified under the Other Income and Deductions category as follows:

24

- 25 ● Services to Third Parties, net of costs
- 26 ● Property Rental Income
- 27 ● Gains and Losses on Disposal of Utility Property
- 28 ● SLA Services to Hydro Ottawa Affiliates, net of costs
- 29 ● Interest and Dividend Income



1 Tables 6 and 7 summarize Other Income and Deductions for the 2016-2025 period. The  
2 revisions to 2016-2019 were made to remove some costs from rate base to non-distribution,  
3 resulting in an increase in Other Revenue. The revision to 2020 was made to include the  
4 offsetting entry to the regulatory asset for the Gains and Losses on Disposal of Fixed Assets  
5 Variance Account, as described in UPDATED Exhibit 9-1-3: Group 2 Accounts. The update in  
6 2020-2022 was made as a result of the updated MiGen project, as described in the updates to  
7 section 2.3.3 in Attachment 2-4-3(E): Material Investments.

8  
9 **Table 6 – AS ORIGINALLY SUBMITTED – Other Income and Deductions 2016-2020**  
10 **(\$'000s)**

Other Income and Deductions	Historical Years			Bridge Years	
	2016	2017	2018	2019	2020
Services to Third Parties (net of costs)	\$949	\$1,021	\$254	\$489	\$1,182
Property Rental Income	\$606	\$629	\$557	\$547	\$516
Gains and (Losses) on Disposal of Utility Property	\$140	\$198	\$198	(\$486)	(\$301)
SLA Services to Hydro Ottawa Affiliates	\$2,063	\$3,305	\$3,797	\$4,439	\$4,683
SLA Costs from Hydro Ottawa Affiliates	\$0	\$0	\$0	(\$3,721)	(\$3,894)
Interest and Dividend Income	\$39	\$76	\$117	\$1	\$0
<b>TOTAL<sup>17</sup></b>	<b>\$3,796</b>	<b>\$5,230</b>	<b>\$4,923</b>	<b>\$1,270</b>	<b>\$2,186</b>

11  
12 **Table 6 – AS REVISED– Other Income and Deductions 2016-2020 (\$'000s)**

Other Income and Deductions	Historical Years			Bridge Years	
	2016	2017	2018	2019	2020
Services to Third Parties (net of costs)	\$949	\$1,030	\$500	\$728	\$1,182
Property Rental Income	\$606	\$629	\$557	\$547	\$516
Gains and (Losses) on Disposal of Utility Property	\$140	\$198	\$198	(\$486)	\$198
SLA Services to Hydro Ottawa Affiliates	\$2,063	\$3,305	\$3,797	\$4,439	\$4,683
SLA Costs from Hydro Ottawa Affiliates	\$0	\$0	\$0	(\$3,721)	(\$3,894)
Interest and Dividend Income	\$39	\$76	\$117	\$1	\$0
<b>TOTAL<sup>18</sup></b>	<b>\$3,796</b>	<b>\$5,239</b>	<b>\$5,168</b>	<b>\$1,508</b>	<b>\$2,685</b>

13 <sup>17</sup> Totals may not sum due to rounding.

14 <sup>18</sup> Totals may not sum due to rounding.





**Table 6 – UPDATED FOR 2019 ACTUALS – Other Income and Deductions 2016-2020**

(\$'000s)

Other Income and Deductions	Historical Years				Bridge Years
	2016	2017	2018	2019	2020
Services to Third Parties (net of costs)	\$949	\$1,030	\$500	\$385	\$1,188
Property Rental Income	\$606	\$629	\$557	\$564	\$516
Gains and (Losses) on Disposal of Utility Property	\$140	\$198	\$198	\$198	\$198
SLA Services to Hydro Ottawa Affiliates	\$2,063	\$3,305	\$3,797	\$3,835	\$4,683
SLA Costs from Hydro Ottawa Affiliates	\$0	\$0	\$0	(\$3,187)	(\$3,894)
Interest and Dividend Income	\$39	\$76	\$117	\$33	\$0
<b>TOTAL<sup>19</sup></b>	<b>\$3,796</b>	<b>\$5,239</b>	<b>\$5,168</b>	<b>\$1,828</b>	<b>\$2,691</b>

<sup>19</sup> Totals may not sum due to rounding.



**Table 7 – AS ORIGINALLY SUBMITTED – Other Income and Deductions 2021-2025**  
(\$'000s)

Other Income and Deductions	Test Years				
	2021	2022	2023	2024	2025
Services to Third Parties (net of costs)	\$1,133	\$1,140	\$974	\$1,130	\$1,117
Property Rental Income	\$516	\$516	\$516	\$516	\$516
Gains and (Losses) on Disposal of Utility Property	(\$389)	(\$751)	(\$323)	(\$336)	(\$445)
SLA Services to Hydro Ottawa Affiliates	\$4,800	\$4,920	\$5,043	\$5,169	\$5,298
SLA Costs from Hydro Ottawa Affiliates	(\$3,991)	(\$4,091)	(\$4,193)	(\$4,298)	(\$4,406)
Interest and Dividend Income	\$0	\$0	\$0	\$0	\$0
<b>TOTAL<sup>20</sup></b>	<b>\$2,069</b>	<b>\$1,733</b>	<b>\$2,017</b>	<b>\$2,181</b>	<b>\$2,081</b>

**Table 7 – UPDATED FOR 2019 ACTUALS – Other Income and Deductions 2021-2025**  
(\$'000s)

Other Income and Deductions	Test Years				
	2021	2022	2023	2024	2025
Services to Third Parties (net of costs)	\$1,170	\$1,097	\$974	\$1,130	\$1,117
Property Rental Income	\$516	\$516	\$516	\$516	\$516
Gains and (Losses) on Disposal of Utility Property	(\$389)	(\$751)	(\$323)	(\$336)	(\$445)
SLA Services to Hydro Ottawa Affiliates	\$4,800	\$4,920	\$5,043	\$5,169	\$5,298
SLA Costs from Hydro Ottawa Affiliates	(\$3,991)	(\$4,091)	(\$4,193)	(\$4,298)	(\$4,406)
Interest and Dividend Income	\$0	\$0	\$0	\$0	\$0
<b>TOTAL<sup>21</sup></b>	<b>\$2,105</b>	<b>\$1,691</b>	<b>\$2,017</b>	<b>\$2,181</b>	<b>\$2,081</b>

#### 5.1. SERVICES TO THIRD PARTIES

These revenues, net of expenses, relate to services provided to customers or third parties beyond the standard temporary services included in Specific Service Charges (as itemized in Tables 2 and 3 above). These additional services may include isolating and re-energizing services, mutual aid services, transformer vault shutdown escort services, inspection services, generator services, and a recently introduced bill reporting service. A small amount of revenue

<sup>20</sup> Totals may not sum due to rounding.

<sup>21</sup> Totals may not sum due to rounding.



1 is also forecasted for providing ad hoc web portal services for viewing interval meter data in a  
2 web-based format. Services to the City of Ottawa and to affiliates for the aforementioned  
3 services are included in USofA 4325 Revenues from Merchandise and 4330 Costs and  
4 Expenses of Merchandising.

5

6 Hydro Ottawa rents out its underground civil capacity to third parties, on a temporary basis,  
7 through a five-year Access Agreement. These duct rental agreements exist with the City of  
8 Ottawa and a major telecommunications provider. Hydro Ottawa has several third parties which  
9 pay the applicable Specific Service Charge for wireline pole attachments. These third parties  
10 include street light owners, telecommunications providers, and Hydro One Networks Inc.  
11 ("HONI").

12

### 13 **5.2. PROPERTY RENTAL INCOME**

14 Property rental relates to fees paid by HONI for land owned by Hydro Ottawa. In many locations  
15 in the City of Ottawa, Hydro Ottawa and HONI have joint facilities for transformer stations. For  
16 locations in which Hydro Ottawa owns the land on which HONI has facilities, a rental fee is paid.

17

18 An additional source of income is from rent paid by the tenants of a small number of houses that  
19 were previously purchased by Hydro Ottawa and that are located adjacent to certain distribution  
20 stations. These houses were purchased to facilitate future station expansion.

21

### 22 **5.3. GAINS AND LOSSES ON DISPOSAL OF UTILITY PROPERTY**

23 Hydro Ottawa periodically disposes of assets that are no longer necessary or re-usable in  
24 serving the public (e.g. end-of-life assets, asset failure, damaged beyond repair, relocation  
25 requests from third parties, surplus inventory, obsolescence, etc.). Where the proceeds vary  
26 from the net book value of an asset, Hydro Ottawa treats the variances as a debit or credit to  
27 income.



1 Hydro Ottawa applies the associated gains and losses to USofA 1508 Other Regulatory Assets  
2 - Sub-Account - Gains and Loss on Disposal of Fixed Assets Variance Account. Please refer to  
3 **UPDATED** Exhibit 9-1-3: Group 2 Accounts for further details on Account 1508.

4

5 As per the Approved Settlement Agreement governing Hydro Ottawa's 2016-2020 rate term, the  
6 utility is recording the net gain on the sale of the Albion land and building, as well as the  
7 Merivale land and building, in a separate regulatory account (Gains/Losses from Sale of  
8 Existing Facilities Deferral account). This account captures 100% of the after tax net gain/loss  
9 on the sale of these facilities. Please see **UPDATED** Exhibit 9-3-1: Group 2 Accounts for more  
10 information on this Regulatory Account.

11

#### 12 **5.4. SERVICES TO HYDRO OTTAWA AFFILIATES**

13 Hydro Ottawa provides services to its affiliates under the terms of Service Level Agreements  
14 ("SLAs"), which are updated annually. These affiliates are Hydro Ottawa Holding Inc. (the  
15 utility's parent company), as well as Energy Ottawa Inc. and Envari Holding Inc.

16

17 Hydro Ottawa provides Human Resources, Safety, Environment, Business Continuity, Facilities,  
18 Information Technology and Management, Finance, Regulatory, Legal, Communications, Key  
19 Account Support, Electricity Distribution Management, Meter Data, Fleet, and Mechanic  
20 Services to its affiliates. As described in section 5.1 above, in addition to shared corporate  
21 services Hydro Ottawa provides distribution design, flood restoration work, streetlight  
22 conversion, and emergency response to Energy Ottawa. Table 8 below provides a summary of  
23 all revenues earned from services provided to affiliates, whether through SLAs or other  
24 contractual arrangements.

25

26 Additional detail on the services Hydro Ottawa provides to and receives from affiliates is  
27 available in Exhibit 4-2-1: Shared Services and Corporate Cost Allocation.

1 Consistent with section 2.4.3.2 of the *Chapter 2 Filing Requirements for Electricity Distribution*  
2 *Rate Applications*, as updated on July 12, 2018 and addended on July 15, 2019, as well as with  
3 OEB guidance issued in 2018, SLA costs are no longer included in OM&A.<sup>22</sup> For additional  
4 details, please see Exhibit 4-2-1: Shared Services and Corporate Cost Allocation and  
5 **UPDATED** Exhibit 4-1-4: Operations, Maintenance and Administration Cost Drivers and  
6 Program Variance Analysis for additional details.

7

8 Prior to 2019, Hydro Ottawa recorded the SLA revenue in USofA 4325 as Revenues from  
9 Merchandising and Jobbing, and applied the associated costs to OM&A. With the growth of  
10 Hydro Ottawa's affiliates, the amounts charged to these affiliates and the associated costs  
11 through SLAs have increased significantly, as outlined in **UPDATED** Attachment 3-2-1(B): OEB  
12 Appendix 2-N - Shared Services and Corporate Cost Allocation. The costs, along with the  
13 associated SLA revenue, are now reported in USofA 4330 Costs from Merchandising and  
14 Jobbing and are therefore not included in OM&A as of 2019.

---

15 <sup>22</sup> Ontario Energy Board, Presentation re: *Chapter 1 & 2 Filing Requirements Update for 2019 Applications: Summary*  
16 *of Key Changes* (July 19, 2018), slides 15-16.



1 **Table 8 – AS ORIGINALLY SUBMITTED – Summary of Total Affiliate Services Revenue**  
2 **Earned by Hydro Ottawa**

Provided By	Provided To	Historical Years			Bridge Years		Test Year
		2016	2017	2018	2019	2020	2021
Hydro Ottawa	Holding Company	\$861,944	\$690,560	\$1,093,093	\$1,330,390	\$1,450,389	\$1,486,649
Hydro Ottawa	Energy Ottawa	\$1,357,368	\$3,144,697	\$2,997,085	\$2,156,286	\$1,669,891	\$1,711,638
Hydro Ottawa	Enviri	\$0	\$0	\$0	\$1,688,131	\$1,562,625	\$1,601,691
<b>TOTAL</b>		<b>\$2,219,312</b>	<b>\$3,835,257</b>	<b>\$4,090,179</b>	<b>\$5,174,807</b>	<b>\$4,682,905</b>	<b>\$4,799,978</b>

3  
4 **Table 8 – UPDATED FOR 2019 ACTUALS – Summary of Total Affiliate Services Revenue**  
5 **Earned by Hydro Ottawa**

Provided By	Provided To	Historical Years				Bridge Years	Test Year
		2016	2017	2018	2019	2020	2021
Hydro Ottawa	Holding Company	\$861,944	\$690,560	\$1,093,093	\$1,216,876	\$1,450,389	\$1,486,649
Hydro Ottawa	Energy Ottawa	\$1,357,368	\$3,144,697	\$2,997,085	\$1,955,383	\$1,669,891	\$1,711,638
Hydro Ottawa	Enviri	\$0	\$0	\$0	\$1,656,960	\$1,562,625	\$1,601,691
<b>TOTAL</b>		<b>\$2,219,312</b>	<b>\$3,835,257</b>	<b>\$4,090,179</b>	<b>\$4,829,219</b>	<b>\$4,682,905</b>	<b>\$4,799,978</b>

6  
7 **5.5. INTEREST AND DIVIDEND INCOME**

8 Interest income refers to interest earned on cash balances within the year.

9

10 In the years 2016-2018, a modest amount of interest was recorded under USofA Account 4405.

11 Material cash balances are not anticipated between 2019 and 2025.



1 **5.6. VARIANCE ANALYSIS**

2 **5.6.1. 2016 Actual to 2017 Actual**

3 Other Income and Deductions in 2017 increased by \$1.4M, primarily due to the \$1.2M increase  
4 in SLA services to affiliates. Details are provided in Exhibit 4-2-1: Shared Services and  
5 Corporate Cost Allocation.

6

7 **5.6.2. 2017 Actual to 2018 Actual**

8 Other Income and Deductions in 2018 decreased by \$0.3M, due to a decrease in services  
9 provided to third parties, net of costs.

10

11 **5.6.3. 2018 Actual to 2019 Bridge Year**

12 Other Income and Deductions are projected to decrease by \$3.7M in 2019 due to a \$3.7M SLA  
13 cost allocation to USofA 4330 Costs from Merchandising and Jobbing. Additional information is  
14 provided in section 5.4 above. Increased interest income is offset by losses on disposal of utility  
15 property.

16

17 **2018 Actual to 2019 Actual**

18 Other Income and Deductions decreased by \$3.3M in 2019, due to a \$3.2M SLA cost allocation  
19 to USofA 4330 Costs from Merchandising and Jobbing. Additional information is provided in  
20 section 5.4 above.

21

22 **5.6.4. 2019 Bridge Year to 2020 Bridge Year**

23 Other Income and Deductions in 2020 are projected to increase by \$0.9M. Services to third  
24 parties are anticipated to increase.

25

26 **2019 Actual to 2020 Bridge Year**

27 Other Income and Deductions in 2020 are projected to increase by \$0.9M. Services to third  
28 parties are anticipated to increase.

1 **5.6.5. 2020 Bridge Year to 2021 Test Year**

2 Other Income and Deductions for the 2021-2025 Test Years are generally in line with 2020. A  
3 slight increase is forecast in 2022 for loss on disposal of utility property due to a one-time  
4 disposal of meters, as a result of an initiative focused on AMI analytics and integration.  
5 Additional information on this project is available in Exhibit 2-4-3: Distribution System Plan and  
6 Attachment 2-4-3(E): Material Investments. The changes in 2021 and 2022 are the result of the  
7 updated MiGen project, as described in the updates to section 2.3.3 in Attachment 2-4-3(E):  
8 Material Investments.



[illegible]

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

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

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income. Tables for the detailed breakdowns will be generated after cell B89 is filled in.

	2016 Actual <sup>2</sup>	2017 Actual <sup>2</sup>	2018 Actual <sup>2</sup>	2019 Actual	Bridge Year	Test Year	CGAAP
	2016	2017	2018	2019	2020	2021	Enter Transition Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	CGAAP
Short-term Investment Interest							
Bank Deposit Interest	\$ 38,905	\$ 75,768	\$ 116,864	\$ 933	\$ -	\$ -	
Miscellaneous Interest Revenue							
etc.1							
<b>Total</b>	<b>\$ 38,905</b>	<b>\$ 75,768</b>	<b>\$ 116,864</b>	<b>\$ 933</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ -</b>

1 List and specify any other interest revenue.

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

Please refer to Exhibit 3-2-1: Other Revenue, Tables 4 and 5 for a breakdown of "Other Operating Revenue" and Tables 6 and 7 for "Other Income and Deductions".

**UPDATED - Appendix 2-N  
Shared Services and Corporate Cost Allocation 1**

Year: 2016

**Shared Services**

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			\$	\$
HOL	HOHI	Communications	Cost	\$79,722	\$79,722
HOL	HOHI	Facilities	Market/Cost	\$238,441	\$127,795
HOL	HOHI	Finance	Cost	\$170,008	\$170,008
HOL	HOHI	Human Resources	Cost	\$128,904	\$128,904
HOL	HOHI	Information Technology	Cost	\$229,869	\$229,869
HOL	HOHI	Legal	Cost	\$15,000	\$15,000
<b>Total Charged HOL to HOHI</b>				<b>\$861,944</b>	<b>\$751,298</b>
HOL	EO	Administration Support	Cost	\$48,145	\$48,145
HOL	EO	Communications	Cost	\$38,993	\$38,993
HOL	EO	Facilities	Market/Cost	\$88,389	\$62,078
HOL	EO	Finance	Cost	\$115,017	\$115,017
HOL	EO	Human Resources, Safety, Environment and Business Continuity Management	Cost	\$244,119	\$244,119
HOL	EO	Information Technology	Cost	\$459,738	\$459,738
HOL	EO	Meter Data Services	Market	\$73,453	*
HOL	EO	Mechanic Services	Cost	\$132,867	\$132,867
<b>Total Charged HOL to EO</b>				<b>\$1,200,721</b>	<b>\$1,100,957</b>
HOL	CDM	Human Resources	Cost	\$105,358	\$105,358
HOL	CDM	Facilities	Market/Cost	\$50,373	\$30,810
HOL	CDM	Information Technology	Cost	\$187,880	\$187,880
HOL	CDM	Finance	Cost	\$118,536	\$118,536
HOL	CDM	Communications	Cost	\$32,820	\$32,820
HOL	CDM	Fleet	Cost	\$8,544	\$8,544
<b>Total Charged HOL to CDM</b>				<b>\$503,511</b>	<b>\$483,948</b>

\* Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

**Corporate Cost Allocation**

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	\$
HOHI	HOL	Management Services	Cost	46%	\$570,000
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgt	Cost	63%	\$1,220,000
HOHI	HOL	Human Resources	Cost	92%	\$690,000
HOHI	HOL	Treasury	Cost	66%	\$260,000
HOHI	HOL	Corporate Communications	Cost	36%	\$455,760
HOHI	HOL	Legal, Corporate Admin	Cost	38%	\$240,000
HOHI	HOL	Information Management & Technology	Cost	60%	\$320,000
<b>Total Charged from HOHI to HOL</b>					<b>\$3,755,760</b>
HOHI	CDM	Management Services	Cost	14%	\$175,060
<b>Total Charged from HOHI to CDM</b>					<b>\$175,060</b>

**Note:**

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

· **Type of Service:**

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

· **Pricing Methodology:**

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

· **% Allocation:**

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

**UPDATED - Appendix 2-N  
Shared Services and Corporate Cost Allocation 1**

Year: 2017

**Shared Services**

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			\$	\$
HOL	HOHI	Communications	Cost	\$21,130	\$21,130
HOL	HOHI	Facilities	Market/Cost	\$119,806	\$63,543
HOL	HOHI	Finance	Cost	\$41,113	\$41,113
HOL	HOHI	Human Resources	Cost	\$141,807	\$141,807
HOL	HOHI	Information Technology	Cost	\$357,451	\$357,451
HOL	HOHI	Legal	Cost	\$5,688	\$5,688
<b>Total Charged HOL to HOHI</b>				<b>\$686,995</b>	<b>\$630,732</b>
HOL	EO	Administration Support	Cost	\$76,780	\$76,780
HOL	EO	Communications	Cost	\$269,493	\$269,493
HOL	EO	Facilities	Market/Cost	\$123,068	\$80,393
HOL	EO	Finance	Cost	\$1,196,367	\$1,196,367
HOL	EO	Human Resources, Safety, Environment and Business Continuity Management	Cost	\$134,908	\$134,908
HOL	EO	Information Technology	Cost	\$516,867	\$516,867
HOL	EO	Legal	Cost	\$58,338	\$58,338
HOL	EO	Meter Data Services	Market	\$73,385	*
HOL	EO	Mechanic Services	Cost	\$169,200	\$169,200
<b>Total Charged HOL to EO</b>				<b>\$2,618,406</b>	<b>\$2,502,346</b>
HOL	CDM	Human Resources	Cost	\$83,430	\$83,430
HOL	CDM	Facilities	Market/Cost	\$59,618	\$32,290
HOL	CDM	Information Technology	Cost	\$219,565	\$219,565
HOL	CDM	Finance	Cost	\$182,665	\$182,665
HOL	CDM	Communications	Cost	\$64,456	\$64,456
HOL	CDM	Fleet	Cost	\$8,544	\$8,544
<b>Total Charged HOL to CDM</b>				<b>\$618,278</b>	<b>\$590,950</b>

\* Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

**Corporate Cost Allocation**

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	\$
HOHI	HOL	Management Services	Cost	46%	\$570,000
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgt	Cost	65%	\$1,270,000
HOHI	HOL	Human Resources	Cost	92%	\$820,000
HOHI	HOL	Treasury	Cost	66%	\$260,000
HOHI	HOL	Corporate Communications	Cost	33%	\$363,215
HOHI	HOL	Legal, Corporate Admin	Cost	38%	\$240,000
HOHI	HOL	Information Management & Technology	Cost	45%	\$270,000
<b>Total Charged from HOHI to HOL</b>					<b>\$3,793,215</b>
HOHI	CDM	Management Services	Cost	10%	\$106,785
<b>Total Charged from HOHI to CDM</b>					<b>\$106,785</b>

**Note:**

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

• **Type of Service:**

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

• **Pricing Methodology:**

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

• **% Allocation:**

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

**UPDATED - Appendix 2-N**  
**Shared Services and Corporate Cost Allocation 1**

Year: 2018

**Shared Services**

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			\$	\$
HOL	HOHI	Communications	Cost	\$234,981	\$234,981
HOL	HOHI	Facilities	Market/Cost	\$130,939	\$71,421
HOL	HOHI	Finance	Cost	\$41,642	\$41,642
HOL	HOHI	Human Resources	Cost	\$150,465	\$150,465
HOL	HOHI	Information Technology	Cost	\$325,518	\$325,518
HOL	HOHI	Legal	Cost	\$9,048	\$9,048
HOL	HOHI	Regulatory	Cost	\$139,811	\$139,811
HOL	HOHI	Electricity Distribution Management	Cost	\$49,580	\$49,580
<b>Total Charged HOL to HOHI</b>				<b>\$1,081,984</b>	<b>\$1,022,466</b>
HOL	EO	Electricity Distribution Management	Cost	\$49,580	\$49,580
HOL	EO	Communications	Cost	\$413,215	\$413,215
HOL	EO	Facilities	Market/Cost	\$118,036	\$63,903
HOL	EO	Finance	Cost	\$972,916	\$972,916
HOL	EO	Fleet	Cost	\$11,731	\$11,731
HOL	EO	Human Resources, Safety, Environment and Business Continuity Management	Cost	\$394,771	\$394,771
HOL	EO	Information Technology	Cost	\$488,280	\$488,280
HOL	EO	Legal	Cost	\$31,316	\$31,316
HOL	EO	Meter Data Services	Market	\$77,617	*
HOL	EO	Mechanic Services	Cost	\$157,282	\$157,282
<b>Total Charged HOL to EO</b>				<b>\$2,714,744</b>	<b>\$2,582,994</b>
HOL	CDM	Human Resources	Cost	\$107,830	\$107,830
HOL	CDM	Facilities	Market/Cost	\$65,470	\$35,711
HOL	CDM	Information Technology	Cost	\$244,140	\$244,140
HOL	CDM	Finance	Cost	\$149,642	\$149,642
HOL	CDM	Communications	Cost	\$68,076	\$68,076
HOL	CDM	Fleet	Cost	\$17,784	\$17,784
<b>Total Charged HOL to CDM</b>				<b>\$652,942</b>	<b>\$623,183</b>

\* Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

**Corporate Cost Allocation**

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	\$
HOHI	HOL	Management Services	Cost	56%	\$685,479
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgt	Cost	53%	\$970,752
HOHI	HOL	Human Resources	Cost	80%	\$463,026
HOHI	HOL	Treasury	Cost	73%	\$102,694
HOHI	HOL	Corporate Communications	Cost	58%	\$546,685
HOHI	HOL	Legal, Corporate Admin	Cost	23%	\$142,444
HOHI	HOL	Information Management & Technology	Cost	45%	\$311,256
<b>Total Charged from HOHI to HOL</b>					<b>\$3,222,336</b>
HOHI	CDM	Management Services	Cost	11%	\$92,207
<b>Total Charged from HOHI to CDM</b>					<b>\$92,207</b>

**Note:**

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

· **Type of Service:**

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

· **Pricing Methodology:**

· **% Allocation:**

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

**UPDATED - Appendix 2-N**  
**Shared Services and Corporate Cost Allocation 1**

Year: 2019

**Shared Services**

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			\$	\$
HOL	HOHI	Electricity Distribution Management	Cost	\$49,044	\$49,044
HOL	HOHI	Communications	Cost	\$226,585	\$226,585
HOL	HOHI	Facilities	Market/Cost	\$168,648	\$87,629
HOL	HOHI	Finance	Cost	\$24,516	\$24,516
HOL	HOHI	Human Resources	Cost	\$140,810	\$140,810
HOL	HOHI	Information Technology	Cost	\$357,593	\$357,593
HOL	HOHI	Legal	Cost	\$9,984	\$9,984
HOL	HOHI	Regulatory	Cost	\$183,276	\$183,276
HOL	HOHI	Engineering Services	Cost	\$14,157	\$14,157
<b>Total Charged HOL to HOHI</b>				<b>\$1,174,613</b>	<b>\$1,093,594</b>
HOL	EO	Electricity Distribution Management	Cost	\$0	\$0
HOL	EO	Communications	Cost	\$184,462	\$184,462
HOL	EO	Facilities	Market/Cost	\$20,736	\$11,781
HOL	EO	Finance	Cost	\$455,147	\$455,147
HOL	EO	Human Resources, Safety, Environment and Business Continuity Management	Cost	\$146,482	\$146,482
HOL	EO	Information Technology	Cost	\$311,450	\$311,450
HOL	EO	Legal	Cost	\$24,960	\$24,960
HOL	EO	Regulatory Affairs	Cost	\$91,632	\$91,632
HOL	EO	Meter Data Services	Market	\$18,600	*
HOL	EO	Mechanic Services	Cost	\$158,043	\$158,043
<b>Total Charged HOL to EO</b>				<b>\$1,411,512</b>	<b>\$1,383,957</b>
HOL	CDM	Human Resources	Cost	\$77,864	\$77,864
HOL	CDM	Facilities	Market/Cost	\$35,231	\$15,635
HOL	CDM	Information Technology	Cost	\$165,690	\$165,690
HOL	CDM	Finance	Cost	\$57,500	\$57,500
HOL	CDM	Communications	Cost	\$63,672	\$63,672
HOL	CDM	Fleet	Cost	\$9,960	\$9,960
<b>Total Charged HOL to CDM</b>				<b>\$409,917</b>	<b>\$390,321</b>
HOL	Enviri	Electricity Distribution Management	Cost	\$24,516	\$24,516
HOL	Enviri	Communications	Cost	\$187,289	\$187,289
HOL	Enviri	Facilities	Market/Cost	\$89,088	\$53,507
HOL	Enviri	Finance	Cost	\$220,230	\$220,230
HOL	Enviri	Fleet	Cost	\$9,781	\$9,781
HOL	Enviri	Human Resources	Cost	\$136,267	\$136,267
HOL	Enviri	Information Technology	Cost	\$346,057	\$346,057
HOL	Enviri	Key Accounts	Cost	\$60,372	\$60,372
HOL	Enviri	Legal	Cost	\$24,960	\$24,960
HOL	Enviri	Regulatory	Cost	\$91,632	\$91,632
HOL	Enviri	Data Services	Cost	\$58,278	\$58,278
<b>Total Charged HOL to Enviri</b>				<b>\$1,248,470</b>	<b>\$1,212,889</b>

\* Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

**Corporate Cost Allocation**

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	\$
HOHI	HOL	Management Services	Cost	50%	\$525,476
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgt	Cost	67%	\$976,909
HOHI	HOL	Human Resources	Cost	80%	\$434,491
HOHI	HOL	Treasury	Cost	56%	\$76,900
HOHI	HOL	Corporate Communications	Cost	55%	\$494,141
HOHI	HOL	Legal, Corporate Admin	Cost	40%	\$140,123
HOHI	HOL	Information Management & Technology	Cost	45%	\$319,920
<b>Total Charged from HOHI to HOL</b>					<b>\$2,967,960</b>
HOHI	CDM	Management Services	Cost	10%	\$105,817
<b>Total Charged from HOHI to CDM</b>					<b>\$105,817</b>

**Note:**

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

• **Type of Service:**

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

• **Pricing Methodology:**

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

• **% Allocation:**

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

**Appendix 2-N  
Shared Services and Corporate Cost Allocation 1**

Year: 2020

**Shared Services**

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			\$	\$
HOL	HOHI	Electricity Distribution Management	Cost	\$53,330	\$53,330
HOL	HOHI	Communications	Cost	\$236,781	\$236,781
HOL	HOHI	Facilities	Market/Cost	\$215,451	\$118,800
HOL	HOHI	Finance	Cost	\$17,770	\$17,770
HOL	HOHI	Human Resources	Cost	\$196,225	\$196,225
HOL	HOHI	Information Technology	Cost	\$515,803	\$515,803
HOL	HOHI	Legal	Cost	\$9,101	\$9,101
HOL	HOHI	Regulatory	Cost	\$205,928	\$205,928
<b>Total Charged HOL to HOHI</b>				<b>\$1,450,389</b>	<b>\$1,353,738</b>
HOL	EO	Communications	Cost	\$187,177	\$187,177
HOL	EO	Facilities	Market/Cost	\$27,318	\$15,627
HOL	EO	Finance	Cost	\$466,908	\$466,908
HOL	EO	Human Resources, Safety, Environment and Business Continuity Management	Cost	\$217,072	\$217,072
HOL	EO	Information Technology	Cost	\$473,981	\$473,981
HOL	EO	Legal	Cost	\$22,754	\$22,754
HOL	EO	Regulatory Affairs	Cost	\$102,964	\$102,964
HOL	EO	Meter Data Services	Market	\$18,600	*
HOL	EO	Mechanic Services	Cost	\$153,117	\$153,117
<b>Total Charged HOL to EO</b>				<b>\$1,669,891</b>	<b>\$1,639,600</b>
HOL	CDM	HR	Cost	\$35,385	\$35,385
HOL	CDM	Facilities	Market/Cost	\$17,697	\$9,025
HOL	CDM	Information Technology	Cost	\$75,825	\$75,825
HOL	CDM	Finance	Cost	\$33,000	\$33,000
HOL	CDM	Communications	Cost	\$27,335	\$27,335
<b>Total Charged HOL to CDM</b>				<b>\$189,242</b>	<b>\$180,570</b>
HOL	Enviri	Electricity Distribution Management	Cost	\$26,665	\$26,665
HOL	Enviri	Communications	Cost	\$187,177	\$187,177
HOL	Enviri	Facilities	Market/Cost	\$122,734	\$74,648
HOL	Enviri	Finance	Cost	\$180,290	\$180,290
HOL	Enviri	Fleet	Cost	\$11,731	\$11,731
HOL	Enviri	Human Resources	Cost	\$217,439	\$217,439
HOL	Enviri	Information Technology	Cost	\$571,566	\$571,566
HOL	Enviri	Key Accounts	Cost	\$60,747	\$60,747
HOL	Enviri	Legal	Cost	\$22,754	\$22,754
HOL	Enviri	Regulatory	Cost	\$102,964	\$102,964
HOL	Enviri	Data Services	Cost	\$58,560	\$58,560
<b>Total Charged HOL to Enviri</b>				<b>\$1,562,627</b>	<b>\$1,514,541</b>

\* Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

**Corporate Cost Allocation**

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	\$
HOHI	HOL	Management Services	Cost	50%	\$684,969
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgt	Cost	57%	\$1,148,327
HOHI	HOL	Human Resources	Cost	80%	\$550,297
HOHI	HOL	Treasury	Cost	66%	\$91,705
HOHI	HOL	Corporate Communications	Cost	57%	\$746,473
HOHI	HOL	Legal, Corporate Admin	Cost	20%	\$179,766
HOHI	HOL	Information Management & Technology	Cost	45%	\$321,179
<b>Total Charged from HOHI to HOL</b>					<b>\$3,722,716</b>
HOHI	CDM	Management Services	Cost	3%	\$45,898
<b>Total Charged from HOHI to CDM</b>					<b>\$45,898</b>

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• **Type of Service:**

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