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:

- 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
- 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 Attachment 3-1-1(A): Appendix 2-IB OEB - Load Forecast Analysis[1] 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.

[1] Hydro Ottawa has made adjustments to Appendix 2-IB to include rows for the 2021-2025 forecast.

2. LOAD FORECAST

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

Table 1 – 2021-2025 Energy Sales Forecast by Customer Class (MWh)[2]

	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
TOTAL MWh SALES	**7,065,745**	**7,088,184**	**7,116,619**	**7,165,092**	**7,179,631**

Table 2 below provides Hydro Ottawa's demand forecast by kW for 2021-2025.

[2] This forecast does not include the Dry Core Transformer Charge.

Table 2 – 2021-2025 Demand Sales Forecast by Customer 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
TOTAL KW DEMAND SALES	**9,456,512**	**9,452,590**	**9,452,792**	**9,472,485**	**9,457,798**

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
TOTAL CUSTOMERS	**344,939**	**348,107**	**351,141**	**354,091**	**357,020**

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
TOTAL CONNECTIONS	**66,182**	**67,101**	**68,021**	**68,940**	**69,860**

4. TRANSFORMER OWNERSHIP CREDIT FORECAST

Table 5 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 Exhibit 8-1-1: Fixed/Variable Proportion for more details.

Table 5 – 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
TOTAL KW DEMAND SALES	**2,346,838**	**2,346,539**	**2,347,151**	**2,352,635**	**2,349,424**

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

- Attachment 6-1-1(A): OEB Workform - 2021 Revenue Requirement Workform
- Attachment 6-1-1(B): OEB Workform - 2022 Revenue Requirement Workform
- Attachment 6-1-1(C): OEB Workform - 2023 Revenue Requirement Workform
- Attachment 6-1-1(D): OEB Workform - 2024 Revenue Requirement Workform
- Attachment 6-1-1(E): OEB Workform - 2025 Revenue Requirement Workform

5. CDM ADJUSTMENTS

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

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

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

Table 6 – 2021-2025 Energy Sales CDM Adjustments by Customer Class (MWh)[3]

	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
TOTAL MWh SALES	**162,517**	**185,852**	**207,169**	**228,488**	**247,464**

[3] This forecast does not include the Dry Core Transformer Charge.

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

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
TOTAL KW DEMAND SALES	**260,053**	**297,884**	**331,277**	**364,614**	**395,017**

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	7,404,408,000		
Historical	2016		Actual	7,407,917,661	7,262,299,000	OEB-approved	
Historical	2017		Actual	7,221,217,891	7,273,222,000		
Historical	2018		Actual	7,396,491,892	7,185,136,000		
Bridge Year	2019		Actual	0	7,239,278,000		
Bridge Year	2020		Forecast		7,131,075,000		
Test Year	2021		Forecast		7,065,745,000		
Test Year	2022		Forecast		7,088,184,000		
Test Year	2023		Forecast		7,116,619,000		
Test Year	2024		Forecast		7,165,092,000		
Test Year	2025		Forecast		7,179,631,000		

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	-100.0%	0.8%		
	2020		-1.5%		
	2021		-0.9%		
	2022		0.3%		
	2023		0.4%		
	2024		0.7%		
	2025		0.2%		
	Geometric Mean	-100.0%	-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			
Historical	*2015*	Actual	293,884		
Historical	*2016*	Actual	298,001	OEB-approved	
Historical	*2017*	Actual	301,839		
Historical	*2018*	Actual	305,390		
Bridge Year	*2019*	Forecast	309,165		
Bridge Year	*2020*	Forecast	313,134		
Test Year	*2021*	Forecast	316,346		
Test Year	*2022*	Forecast	319,386		
Test Year	*2023*	Forecast	322,306		
Test Year	*2024*	Forecast	325,150		
Test Year	*2025*	Forecast	327,975		

	Calendar Year	Consumption (kWh) (3)				
			Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2015*	Actual	2,242,517,759	2,241,278,000		
Historical	*2016*	Actual	2,260,335,626	2,203,868,000	OEB-approved	
Historical	*2017*	Actual	2,188,889,238	2,232,964,000		
Historical	*2018*	Actual	2,318,157,312	2,227,860,000		
Bridge Year	*2019*	Forecast		2,263,788,000		
Bridge Year	*2020*	Forecast		2,254,563,000		
Test Year	*2021*	Forecast		2,253,081,000		
Test Year	*2022*	Forecast		2,273,964,000		
Test Year	*2023*	Forecast		2,299,513,000		
Test Year	*2024*	Forecast		2,333,345,000		
Test Year	*2025*	Forecast		2,353,299,000		

	Calendar Year	Consumption (kWh) per Customer				
			Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2015*	Actual	7,630.62	7,626.40		
Historical	*2016*	Actual	7,584.99	7,395.51	OEB-approved	
Historical	*2017*	Actual	7,251.84	7,397.86		
Historical	*2018*	Actual	7,590.81	7,295.13		
Bridge Year	*2019*	Forecast	0.00	7,322.26		
Bridge Year	*2020*	Forecast	0.00	7,199.99		
Test Year	*2021*	Forecast	0.00	7,122.20		
Test Year	*2022*	Forecast	0.00	7,119.80		
Test Year	*2023*	Forecast	0.00	7,134.56		
Test Year	*2024*	Forecast	0.00	7,176.21		
Test Year	*2025*	Forecast	0.00	7,175.24		

Variance Analysis	Year	Customers Year-over-year	Test Year Versus OEB-approved	Year	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Year	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	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%	
Bridge Year	*2019*	1.2%		*2019*	-100.0%	1.6%		*2019*	-100.0%	0.4%	
Bridge Year	*2020*	1.3%		*2020*		-0.4%		*2020*		-1.7%	
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	-100.0%	0.5%		Geometric Mean	-100.0%	-0.7%	

	Calendar Year (for 2021 Cost of Service	Revenues			
Historical	*2015*	Actual	$ 86,662,173		
Historical	*2016*	Actual	$ 90,945,757	OEB-approved	
Historical	*2017*	Actual	$ 92,970,029		
Historical	*2018*	Actual	$ 99,559,087		
Bridge Year	*2019*	Forecast	$ 102,025,319		
Bridge Year	*2020*	Forecast	$ 104,307,875		
Test Year	*2021*	Forecast	$ 115,137,290		
Test Year	*2022*	Forecast	$ 124,905,477		
Test Year	*2023*	Forecast	$ 131,384,818		
Test Year	*2024*	Forecast	$ 136,367,910		
Test Year	*2025*	Forecast	$ 139,953,492		

	Calendar Year	Demand (kW)				
			Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2015*	Actual				
Historical	*2016*	Actual			OEB-approved	
Historical	*2017*	Actual				
Historical	*2018*	Actual				
Bridge Year	*2019*	Forecast				
Bridge Year	*2020*	Forecast				
Test Year	*2021*	Forecast				
Test Year	*2022*	Forecast				
Test Year	*2023*	Forecast				
Test Year	*2024*	Forecast				
Test Year	*2025*	Forecast				

	Calendar Year	Demand (kW) per Customer				
			Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2015*	Actual	0	0		
Historical	*2016*	Actual	0	0	OEB-approved	
Historical	*2017*	Actual	0	0		
Historical	*2018*	Actual	0	0		
Bridge Year	*2019*	Forecast	0	0		
Bridge Year	*2020*	Forecast	0	0		
Test Year	*2021*	Forecast	0	0		
Test Year	*2022*	Forecast	0	0		
Test Year	*2023*	Forecast	0	0		
Test Year	*2024*	Forecast	0	0		
Test Year	*2025*	Forecast	0	0		

Variance Analysis	Year	Revenues Year-over-year	Test Year Versus OEB-approved	Year	Demand Year-over-year	Test Year Versus OEB-approved	Year	Demand per Customer 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*		
Bridge Year	*2019*	2.5%		*2019*			*2019*		
Bridge Year	*2020*	14.7%		*2020*			*2020*		
Test Year	*2021*	10.4%		*2021*			*2021*		
Test Year	*2022*	8.5%		*2022*			*2022*		
Test Year	*2024*	9.2%		*2024*			*2024*		
Test Year	*2025*	2.6%		*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			
Historical	2015	Actual	24,392		
Historical	2016	Actual	24,623	OEB-approved	
Historical	2017	Actual	24,786		
Historical	2018	Actual	24,926		
Bridge Year	2019	Forecast	25,030		
Bridge Year	2020	Forecast	25,200		
Test Year	2021	Forecast	25,391		
Test Year	2022	Forecast	25,554		
Test Year	2023	Forecast	25,704		
Test Year	2024	Forecast	25,846		
Test Year	2025	Forecast	25,987		

	Calendar Year	Consumption (kWh) (3)				
			Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2015	Actual	723,754,871	722,460,000		
Historical	2016	Actual	733,311,565	724,984,000	OEB-approved	
Historical	2017	Actual	712,368,648	719,547,000		
Historical	2018	Actual	727,990,864	712,044,000		
Bridge Year	2019	Forecast		724,602,000		
Bridge Year	2020	Forecast		707,799,000		
Test Year	2021	Forecast		700,163,000		
Test Year	2022	Forecast		699,456,000		
Test Year	2023	Forecast		697,989,000		
Test Year	2024	Forecast		698,161,000		
Test Year	2025	Forecast		696,245,000		

	Calendar Year	Consumption (kWh) per Customer				
			Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2015	Actual	29,671.81	29,618.73		
Historical	2016	Actual	29,781.57	29,443.37	OEB-approved	
Historical	2017	Actual	28,740.77	29,030.38		
Historical	2018	Actual	29,206.08	28,566.32		
Bridge Year	2019	Forecast	0.00	28,949.34		
Bridge Year	2020	Forecast	0.00	28,087.26		
Test Year	2021	Forecast	0.00	27,575.24		
Test Year	2022	Forecast	0.00	27,371.68		
Test Year	2023	Forecast	0.00	27,154.88		
Test Year	2024	Forecast	0.00	27,012.34		
Test Year	2025	Forecast	0.00	26,792.05		

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved
Historical	2015		
Historical	2016	0.9%	
Historical	2017	0.7%	
Historical	2018	0.6%	
Bridge Year	2019	0.4%	
Bridge Year	2020	0.7%	
Test Year	2021	0.8%	
Test Year	2022	0.6%	
Test Year	2023	0.6%	
Test Year	2024	3.3%	
Test Year	2025	0.5%	
	Geometric Mean	0.7%	

Variance Analysis	Year	Year-over-year		Test Year Versus OEB-approved
Historical	2015			
Historical	2016	1.3%	0.3%	
Historical	2017	-2.9%	-0.7%	
Historical	2018	2.2%	-1.0%	
Bridge Year	2019	-100.0%	1.8%	
Bridge Year	2020		-2.3%	
Test Year	2021		-1.1%	
Test Year	2022		-0.1%	
Test Year	2023		-0.2%	
Test Year	2024		-3.6%	
Test Year	2025		-0.3%	
	Geometric Mean		-0.4%	

Variance Analysis	Year	Year-over-year		Test Year Versus OEB-approved
Historical	2015			
Historical	2016	0.4%	-0.6%	
Historical	2017	-3.5%	-1.4%	
Historical	2018	1.6%	-1.6%	
Bridge Year	2019	-100.0%	1.3%	
Bridge Year	2020		-3.0%	
Test Year	2021		-1.8%	
Test Year	2022		-0.7%	
Test Year	2023		-0.8%	
Test Year	2024		-0.5%	
Test Year	2025		-0.8%	
	Geometric Mean	-100.0%	-1.1%	

	Calendar Year (for 2021 Cost of Service)	Revenues			
Historical	2015	Actual	$ 20,147,319		
Historical	2016	Actual	$ 21,249,335	OEB-approved	
Historical	2017	Actual	$ 21,132,353		
Historical	2018	Actual	$ 22,199,693		
Bridge Year	2019	Forecast	$ 23,009,822		
Bridge Year	2020	Forecast	$ 23,280,095		
Test Year	2021	Forecast	$ 24,718,302		
Test Year	2022	Forecast	$ 26,720,616		
Test Year	2023	Forecast	$ 28,120,339		
Test Year	2024	Forecast	$ 29,196,775		
Test Year	2025	Forecast	$ 29,937,710		

	Calendar Year	Demand (kWh)				
			Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2015	Actual				
Historical	2016	Actual			OEB-approved	
Historical	2017	Actual				
Historical	2018	Actual				
Bridge Year	2019	Forecast				
Bridge Year	2020	Forecast				
Test Year	2021	Forecast				
Test Year	2022	Forecast				
Test Year	2023	Forecast				
Test Year	2024	Forecast				
Test Year	2025	Forecast				

	Calendar Year	Demand (kWh) per Customer				
			Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2015	Actual	0	0		
Historical	2016	Actual	0	0	OEB-approved	
Historical	2017	Actual	0	0		
Historical	2018	Actual	0	0		
Bridge Year	2019	Forecast	0	0		
Bridge Year	2020	Forecast	0	0		
Test Year	2021	Forecast				
Test Year	2022	Forecast				
Test Year	2023	Forecast				
Test Year	2024	Forecast				
Test Year	2025	Forecast	0	0		

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved
Historical	2015		
Historical	2016	5.5%	
Historical	2017	-0.6%	
Historical	2018	5.1%	
Bridge Year	2019	3.6%	
Bridge Year	2020	1.2%	
Test Year	2021	6.2%	
Test Year	2022	8.1%	
Test Year	2023	5.2%	
Test Year	2024	3.8%	
Test Year	2025	2.5%	
	Geometric Mean	4.5%	

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

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved
Historical	2015		
Historical	2016		
Historical	2017		
Historical	2018		
Bridge Year	2019		
Bridge Year	2020		
Test Year	2021		
Test Year	2022		
Test Year	2023		
Test Year	2024		
Test Year	2025		
	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		Actual	2,949,262,003	2,945,575,000		Actual	886,729.41	885,620.87	
Historical	2016	Actual	3,207	OEB-approved	Actual	2,958,900,805	2,890,997,000	OEB-approved	Actual	922,638.23	901,464.61	OEB-approved
Historical	2017	Actual	3,215		Actual	2,907,121,740	2,899,049,000		Actual	904,236.93	901,725.97	
Historical	2018	Actual	3,224		Actual	2,971,283,949	2,882,228,000		Actual	921,614.13	893,991.32	
Bridge Year	2019	Forecast	3,181		Forecast		2,884,379,000		Forecast	0.00	906,752.28	
Bridge Year	2020	Forecast	3,146		Forecast		2,839,873,000		Forecast	0.00	902,693.26	
Test Year	2021	Forecast	3,120		Forecast		2,819,476,000		Forecast	0.00	903,678.21	
Test Year	2022	Forecast	3,085		Forecast		2,825,111,000		Forecast	0.00	915,757.21	
Test Year	2023	Forecast	3,049		Forecast		2,831,390,000		Forecast	0.00	928,629.06	
Test Year	2024	Forecast	3,013		Forecast		2,844,419,000		Forecast	0.00	944,048.79	
Test Year	2025	Forecast	2,976		Forecast		2,845,454,000		Forecast	0.00	956,133.74	

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%	
Bridge Year	2019	Forecast	-1.3%		2019	-100.0%	0.1%		2019	-100.0%	1.4%	
Bridge Year	2020	Forecast	-1.1%		2020		-1.5%		2020		-0.4%	
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%	0.9%	

	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		Actual	7,203,146	7,015,544		Actual	0.20064666	0.195420932	
Historical	2016	Actual	$ 36,179,929	OEB-approved	Actual	7,075,314	7,006,074	OEB-approved	Actual	0.19555910	0.193645323	OEB-approved
Historical	2017	Actual	$ 37,626,286		Actual	6,985,551	7,015,544		Actual	0.18565614	0.186453270	
Historical	2018	Actual	$ 39,429,376		Actual	7,171,762	6,960,266		Actual	0.18188880	0.176524882	
Bridge Year	2019	Forecast	$ 40,352,882		Forecast		6,930,957		Forecast			
Bridge Year	2020	Forecast	$ 40,904,860		Forecast		6,867,852		Forecast			
Test Year	2021	Forecast	$ 44,681,435		Forecast		6,816,104		Forecast			
Test Year	2022	Forecast	$ 48,305,908		Forecast		6,818,165		Forecast	0	0.141145571	
Test Year	2023	Forecast	$ 50,802,995		Forecast		6,821,528		Forecast	0	0.134274130	
Test Year	2024	Forecast	$ 52,730,181		Forecast		6,838,752		Forecast	0	0.129693315	
Test Year	2025	Forecast	$ 54,053,167		Forecast		6,831,218		Forecast	0	0.126379607	

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%	-0.1%		2016	-2.5%	-0.9%	
Historical	2017	4.0%		2017	-1.3%	0.1%		2017	-5.1%	-3.7%	
Historical	2018	4.8%		2018	2.7%	-0.8%		2018	-2.0%	-5.3%	
Bridge Year	2019	2.3%		2019	-100.0%	-0.4%		2019	-100.0%	-100.0%	
Bridge Year	2020	1.4%		2020		-0.9%		2020			
Test Year	2021	9.2%		2021		-0.8%		2021			
Test Year	2022	8.1%		2022		0.0%		2022			
Test Year	2023	5.2%		2023		0.0%		2023		-4.9%	
Test Year	2024	3.8%		2024		0.3%		2024		-3.4%	
Test Year	2025	2.5%		2025		-0.1%		2025		-2.6%	
	Geometric Mean	4.7%		Geometric Mean	-100.0%	-0.3%		Geometric Mean	-100.0%	-4.7%	

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			Actual	867,663,053	868,325,000			Actual	10,983,076.	10,991,455.7	
Historical	2016	Actual	72	OEB-approved		Actual	805,583,761	797,371,000	OEB-approved		Actual	11,188,663.	11,074,597.2	OEB-approved
Historical	2017	Actual	74			Actual	753,196,269	759,003,000			Actual	10,178,327.	10,256,797.3	
Historical	2018	Actual	68			Actual	723,849,223	712,925,000			Actual	10,644,841.	10,484,191.1	
Bridge Year	2019	Forecast	67			Forecast		723,102,000			Forecast	0.00	10,792,567.1	
Bridge Year	2020	Forecast	68			Forecast		701,795,000			Forecast	0.00	10,320,514.7	
Test Year	2021	Forecast	68			Forecast		682,977,000			Forecast	0.00	10,043,779.4	
Test Year	2022	Forecast	68			Forecast		682,362,000			Forecast	0.00	10,034,735.2	
Test Year	2023	Forecast	68			Forecast		682,571,000			Forecast	0.00	10,037,808.8	
Test Year	2024	Forecast	68			Forecast		684,488,000			Forecast	0.00	10,066,000.0	
Test Year	2025	Forecast	68			Forecast		683,614,000			Forecast	0.00	10,053,147.0	

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	-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%	
Bridge Year	2019	-1.5%		2019	-100.0%	1.4%		2019	-100.0%	2.9%	
Bridge Year	2020	1.5%		2020		-2.9%		2020		-4.4%	
Test Year	2021	-8.1%		2021		-2.7%		2021		2.2%	
Test Year	2022	-1.5%		2022		1.4%		2022		2.9%	
Test Year	2023	1.5%		2023		-5.3%		2023		-6.7%	
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	-100.0%	-2.6%		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	$ 9,361,880			Actual	1,848,869	1,648,910			Actual	0.19748907	0.176130223	
Historical	2016	Actual	$ 9,521,453	OEB-approved		Actual	1,726,981	1,729,271	OEB-approved		Actual	0.18137789	0.181618399	OEB-approved
Historical	2017	Actual	$ 9,754,449			Actual	1,649,388	1,648,910			Actual	0.16909084	0.169041839	
Historical	2018	Actual	$ 9,406,664			Actual	1,580,852	1,547,429			Actual	0.16805659	0.164503475	
Bridge Year	2019	Forecast	$ 12,358,989			Forecast		1,572,857			Forecast			
Bridge Year	2020	Forecast	$ 12,744,060			Forecast		1,552,781			Forecast			
Test Year	2021	Forecast	$ 11,144,722			Forecast		1,518,349			Forecast			
Test Year	2022	Forecast	$ 12,018,297			Forecast		1,517,223			Forecast	0	0.126242761	
Test Year	2023	Forecast	$ 12,623,958			Forecast		1,517,607			Forecast	0	0.120216417	
Test Year	2024	Forecast	$ 13,091,869			Forecast		1,521,105			Forecast	0	0.116187001	
Test Year	2025	Forecast	$ 13,361,275			Forecast		1,519,514			Forecast	0	0.113725224	

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%	4.9%		2016	-8.2%	3.1%	
Historical	2017	2.4%		2017	-4.5%	-4.6%		2017	-6.8%	-6.9%	
Historical	2018	-3.6%		2018	-4.2%	-6.2%		2018	-0.6%	-2.7%	
Bridge Year	2019	31.4%		2019	-100.0%	1.6%		2019	-100.0%	-100.0%	
Bridge Year	2020	3.1%		2020		-1.3%		2020			
Test Year	2021	-12.5%		2021		-2.2%		2021			
Test Year	2022	7.8%		2022		-0.1%		2022			
Test Year	2023	5.0%		2023		0.0%		2023		-4.8%	
Test Year	2024	3.7%		2024		0.2%		2024		-3.4%	
Test Year	2025	2.1%		2025		-0.1%		2025		-2.1%	
	Geometric Mean	4.0%		Geometric Mean	-100.0%	-0.9%		Geometric Mean	-100.0%	-4.7%	

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			Actual	564,803,671	565,577,000		Actual	56,480,367.	56,557,700.0	
Historical	2016	Actual	11	OEB-approved		Actual	588,872,536	584,167,000	OEB-approved	Actual	53,533,866.	53,106,090.9	OEB-approved
Historical	2017	Actual	12			Actual	606,156,949	609,177,000		Actual	50,513,079.	50,764,750.0	
Historical	2018	Actual	13			Actual	608,577,999	603,448,000		Actual	46,813,692.	46,419,076.9	
Bridge Year	2019	Forecast	11			Forecast		602,082,000		Forecast	0.00	54,734,727.2	
Bridge Year	2020	Forecast	11			Forecast		588,828,000		Forecast	0.00	53,529,818.1	
Test Year	2021	Forecast	11			Forecast		574,292,000		Forecast	0.00	52,208,363.6	
Test Year	2022	Forecast	11			Forecast		572,889,000		Forecast	0.00	52,080,818.1	
Test Year	2023	Forecast	11			Forecast		572,033,000		Forecast	0.00	52,003,000.0	
Test Year	2024	Forecast	11			Forecast		572,834,000		Forecast	0.00	52,075,818.1	
Test Year	2025	Forecast	11			Forecast		570,390,000		Forecast	0.00	51,853,636.3	

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%	
Bridge Year	2019	-15.4%		2019	-100.0%	-0.2%		2019	-100.0%	17.9%	
Bridge Year	2020	0.0%		2020		-2.2%		2020		-2.2%	
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			Actual	1,045,761	1,114,963		Actual	0.21133236	0.225317034	
Historical	2016	Actual	$ 5,152,898	OEB-approved		Actual	1,071,626	1,070,337	OEB-approved	Actual	0.20796569	0.207715555	OEB-approved
Historical	2017	Actual	$ 6,052,658			Actual	1,100,755	1,114,963		Actual	0.18186307	0.184210471	
Historical	2018	Actual	$ 6,218,737			Actual	1,106,783	1,104,851		Actual	0.17797554	0.177664867	
Bridge Year	2019	Forecast	$ 6,634,003			Forecast		1,105,225		Forecast	0	0.166600015	
Bridge Year	2020	Forecast	$ 6,729,311			Forecast		1,075,011		Forecast	0	0.159750530	
Test Year	2021	Forecast	$ 7,563,629			Forecast		1,052,899		Forecast	0	0.139205532	
Test Year	2022	Forecast	$ 8,153,268			Forecast		1,050,767		Forecast	0	0.128876789	
Test Year	2023	Forecast	$ 8,561,693			Forecast		1,049,467		Forecast	0	0.122577041	
Test Year	2024	Forecast	$ 8,877,331			Forecast		1,050,683		Forecast	0	0.118355731	
Test Year	2025	Forecast	$ 9,051,156			Forecast		1,046,964		Forecast	0	0.115671854	

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%	-4.0%		2016	-1.6%	-7.8%	
Historical	2017	17.5%		2017	2.7%	4.2%		2017	-12.6%	-11.3%	
Historical	2018	2.7%		2018	0.5%	-0.9%		2018	-2.1%	-3.6%	
Bridge Year	2019	6.7%		2019	-100.0%	0.0%		2019	-100.0%	-6.2%	
Bridge Year	2020	1.4%		2020		-2.7%		2020		-4.1%	
Test Year	2021	12.4%		2021		-2.1%		2021		-12.9%	
Test Year	2022	7.8%		2022		-0.2%		2022		-7.4%	
Test Year	2023	5.0%		2023		-0.1%		2023		-4.9%	
Test Year	2024	3.7%		2024		0.1%		2024		-3.4%	
Test Year	2025	2.0%		2025		-0.4%		2025		-2.3%	
	Geometric Mean	6.9%		Geometric Mean	-100.0%	-0.7%		Geometric Mean	-100.0%	-7.1%	

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		Actual	45,151,658	45,150,000		Actual	796.58	796.55	
Historical	2016	Actual	58,588		Actual	45,206,290	45,206,000		Actual	771.60	771.59	
Historical	2017	Actual	58,470		Actual	38,203,632	38,204,000		Actual	653.39	653.39	
Historical	2018	Actual	59,286		Actual	31,723,370	31,723,000		Actual	535.09	535.08	
Bridge Year	2019	Forecast	60,538		Forecast		26,728,000		Forecast	0.00	441.51	
Bridge Year	2020	Forecast	61,886		Forecast		24,064,000		Forecast	0.00	388.84	
Test Year	2021	Forecast	62,806		Forecast		22,107,000		Forecast	0.00	351.99	
Test Year	2022	Forecast	63,725		Forecast		21,225,000		Forecast	0.00	333.07	
Test Year	2023	Forecast	64,645		Forecast		20,413,000		Forecast	0.00	315.77	
Test Year	2024	Forecast	65,564		Forecast		19,603,000		Forecast	0.00	298.99	
Test Year	2025	Forecast	66,484		Forecast		18,854,000		Forecast	0.00	283.59	

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%	
Bridge Year	2019	2.1%		2019	-100.0%	-15.7%		2019	-100.0%	-17.5%	
Bridge Year	2020	2.2%		2020		-10.0%		2020		-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		Actual	125,349	125,350		Actual	0.14628817	0.146289338	
Historical	2016	Actual	$	1,211,096	OEB-approved	Actual	125,463	125,465		Actual	0.10359483	0.103596240	
Historical	2017	Actual	$	1,150,869		Actual	106,296	106,296		Actual	0.09236149	0.092361490	
Historical	2018	Actual	$	1,121,289		Actual	81,768	88,707		Actual	0.07292323	0.079111652	
Bridge Year	2019	Forecast	$	1,357,056		Forecast		74,394		Forecast	0	0.054820140	
Bridge Year	2020	Forecast	$	1,387,140		Forecast		67,032		Forecast			
Test Year	2021	Forecast	$	1,114,249		Forecast		61,588		Forecast	0	0.055273103	
Test Year	2022	Forecast	$	1,206,068		Forecast		58,863		Forecast	0	0.048805705	
Test Year	2023	Forecast	$	1,268,175		Forecast		56,618		Forecast	0	0.044645257	
Test Year	2024	Forecast	$	1,315,952		Forecast		54,373		Forecast	0	0.041318376	
Test Year	2025	Forecast	$	1,350,026		Forecast		52,530		Forecast	0	0.038910361	

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	-29.2%	-29.2%	
Historical	2017	-5.0%		2017	-15.3%	-15.3%		2017	-10.8%	-10.8%	
Historical	2018	-2.6%		2018	-23.1%	-16.5%		2018	-21.0%	-14.3%	
Bridge Year	2019	21.0%		2019	-100.0%	-16.1%		2019	-100.0%	-30.7%	
Bridge Year	2020	2.2%		2020		-9.9%		2020		-100.0%	
Test Year	2021	-19.7%		2021		-8.1%		2021			
Test Year	2022	8.2%		2022		-4.4%		2022		-11.7%	
Test Year	2023	5.1%		2023		-3.8%		2023		-8.5%	
Test Year	2024	3.8%		2024		-4.0%		2024		-7.5%	
Test Year	2025	2.6%		2025		-3.4%		2025		-5.8%	
	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			
Historical	2015	Actual	55		
Historical	2016	Actual	62	OEB-approved	
Historical	2017	Actual	58		
Historical	2018	Actual	57		
Bridge Year	2019	Forecast	55		
Bridge Year	2020	Forecast	55		
Test Year	2021	Forecast	55		
Test Year	2022	Forecast	55		
Test Year	2023	Forecast	55		
Test Year	2024	Forecast	55		
Test Year	2025	Forecast	55		

	Consumption (kWh) (3)			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	48,804	47,000		
Actual	48,064	47,000	OEB-approved	
Actual	51,051	47,000		
Actual	48,433	47,000		
Forecast		47,000		
Forecast		47,000		
Forecast		47,000		
Forecast		47,000		
Forecast		47,000		
Forecast		47,000		
Forecast		47,000		

	Consumption (kWh) per Customer			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	887.35	854.55		
Actual	775.23	758.06	OEB-approved	
Actual	880.19	810.34		
Actual	849.70	824.56		
Forecast	0.00	854.55		
Forecast	0.00	854.55		
Forecast	0.00	854.55		
Forecast	0.00	854.55		
Forecast	0.00	854.55		
Forecast	0.00	854.55		
Forecast	0.00	854.55		

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved
Historical	2015		
Historical	2016	12.7%	
Historical	2017	-6.5%	
Historical	2018	-1.7%	
Bridge Year	2019	-3.5%	
Bridge Year	2020	0.0%	
Test Year	2021	-11.3%	
Test Year	2022	0.0%	
Test Year	2023	0.0%	
Test Year	2024	0.0%	
Test Year	2025	0.0%	
	Geometric Mean	0.0%	

Year	Year-over-year		Test Year Versus OEB-approved
2015			
2016	-1.5%	0.0%	
2017	6.2%	0.0%	
2018	-5.1%	0.0%	
2019	-100.0%	0.0%	
2020		0.0%	
2021		0.0%	
2022		0.0%	
2023		0.0%	
2024		0.0%	
2025		0.0%	
Geometric Mean	-100.0%	0.0%	

Year	Year-over-year		Test Year Versus OEB-approved
2015			
2016	-12.6%	-11.3%	
2017	13.5%	6.9%	
2018	-3.5%	1.8%	
2019	-100.0%	3.6%	
2020		0.0%	
2021		0.0%	
2022		0.0%	
2023		0.0%	
2024		0.0%	
2025		0.0%	
Geometric Mean	-100.0%	0.0%	

	Calendar Year (for 2021 Cost of Service	Revenues			
Historical	2015	Actual	$ 3,036		
Historical	2016	Actual	$ 3,505	OEB-approved	
Historical	2017	Actual	$ 3,912		
Historical	2018	Actual	$ 4,106		
Bridge Year	2019	Forecast	$ 4,858		
Bridge Year	2020	Forecast	$ 4,691		
Test Year	2021	Forecast	$ 4,955		
Test Year	2022	Forecast	$ 5,949		
Test Year	2023	Forecast	$ 6,815		
Test Year	2024	Forecast	$ 7,655		
Test Year	2025	Forecast	$ 8,456		

	Demand (kW)			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	136	132		
Actual	134	132	OEB-approved	
Actual	142	132		
Actual	135	132		
Forecast		132		
Forecast		132		
Forecast		132		
Forecast		132		
Forecast		132		
Forecast		132		
Forecast		132		

	Demand (kW) per Customer			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	0.04479681	0.043479263		
Actual	0.03823120	0.037660592	OEB-approved	
Actual	0.03630060	0.033744228		
Actual	0.03287839	0.032147762		
Forecast	0	0.027171675		
Forecast	0	0.028138989		
Forecast	0	0.026639757		
Forecast	0	0.022188603		
Forecast	0	0.019369038		
Forecast	0	0.017243631		
Forecast	0	0.015610217		

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved
Historical	2015		
Historical	2016	15.5%	
Historical	2017	11.6%	
Historical	2018	5.0%	
Bridge Year	2019	18.3%	
Bridge Year	2020	-3.4%	
Test Year	2021	5.6%	
Test Year	2022	20.1%	
Test Year	2023	14.6%	
Test Year	2024	12.3%	
Test Year	2025	10.5%	
	Geometric Mean	12.1%	

Year	Year-over-year		Test Year Versus OEB-approved
2015			
2016	-1.5%	0.0%	
2017	6.0%	0.0%	
2018	-4.9%	0.0%	
2019	-100.0%	0.0%	
2020		0.0%	
2021		0.0%	
2022		0.0%	
2023		0.0%	
2024		0.0%	
2025		0.0%	
Geometric Mean	-100.0%	0.0%	

Year	Year-over-year		Test Year Versus OEB-approved
2015			
2016	-14.7%	-13.4%	
2017	-5.0%	-10.4%	
2018	-9.4%	-4.7%	
2019	-100.0%	-15.5%	
2020		3.6%	
2021		-5.3%	
2022		-16.7%	
2023		-12.7%	
2024		-11.0%	
2025		-9.5%	
Geometric Mean	-100.0%	-10.8%	

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		
Historical	2015	Actual	3,398		
Historical	2016	Actual	3,416	OEB-approved	
Historical	2017	Actual	3,434		
Historical	2018	Actual	3,440		
Bridge Year	2019	Forecast	3,382		
Bridge Year	2020	Forecast	3,321		
Test Year	2021	Forecast	3,321		
Test Year	2022	Forecast	3,321		
Test Year	2023	Forecast	3,321		
Test Year	2024	Forecast	3,321		
Test Year	2025	Forecast	3,321		

Calendar Year		Consumption (kWh) (3) Actual (Weather actual)	Weather-normalized		Weather-normalized
2015	Actual	15,997,714	15,996,000		
2016	Actual	15,659,015	15,659,000	OEB-approved	
2017	Actual	15,230,364	15,231,000		
2018	Actual	14,860,742	14,861,000		
2019	Forecast		14,550,000		
2020	Forecast		14,106,000		
2021	Forecast		13,602,000		
2022	Forecast		13,130,000		
2023	Forecast		12,663,000		
2024	Forecast		12,195,000		
2025	Forecast		11,728,000		

Calendar Year		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
2015	Actual	4,707.98	4,707.47		
2016	Actual	4,584.02	4,584.02	OEB-approved	
2017	Actual	4,435.17	4,435.35		
2018	Actual	4,319.98	4,320.06		
2019	Forecast	0.00	4,302.19		
2020	Forecast	0.00	4,247.52		
2021	Forecast	0.00	4,095.75		
2022	Forecast	0.00	3,953.63		
2023	Forecast	0.00	3,813.01		
2024	Forecast	0.00	3,672.09		
2025	Forecast	0.00	3,531.47		

Variance Analysis	Year	Customers Year-over-year	Test Year Versus OEB-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus OEB-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus OEB-approved
Historical	2015								
Historical	2016	0.5%		-2.1%	-2.1%		-2.6%	-2.6%	
Historical	2017	0.5%		-2.7%	-2.7%		-3.2%	-3.2%	
Historical	2018	0.2%		-2.4%	-2.4%		-2.6%	-2.6%	
Bridge Year	2019	-1.7%		-100.0%	-2.1%		-100.0%	-0.4%	
Bridge Year	2020	-1.8%			-3.1%			-1.3%	
Test Year	2021	-2.8%			-3.6%			-10.7%	
Test Year	2022	0.0%			-3.5%			-3.5%	
Test Year	2023	0.0%			-3.6%			-3.6%	
Test Year	2024	0.0%			-3.7%			-3.7%	
Test Year	2025	0.0%			-3.8%			-3.8%	
	Geometric Mean	-0.3%		-100.0%	-3.4%		-100.0%	-3.1%	

	Calendar Year (for 2021 Cost of Service)		Revenues		
Historical	2015	Actual	$ 521,845		
Historical	2016	Actual	$ 534,169	OEB-approved	
Historical	2017	Actual	$ 529,459		
Historical	2018	Actual	$ 376,075		
Bridge Year	2019	Forecast	$ 619,788		
Bridge Year	2020	Forecast	$ 631,316		
Test Year	2021	Forecast	$ 580,271		
Test Year	2022	Forecast	$ 628,486		
Test Year	2023	Forecast	$ 661,040		
Test Year	2024	Forecast	$ 685,855		
Test Year	2025	Forecast	$ 704,189		

Calendar Year		Demand (kWh) Actual (Weather actual)	Weather-normalized		Weather-normalized
2015	Actual				
2016	Actual			OEB-approved	
2017	Actual				
2018	Actual				
2019	Forecast				
2020	Forecast				
2021	Forecast				
2022	Forecast				
2023	Forecast				
2024	Forecast				
2025	Forecast				

Calendar Year		Demand (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
2015	Actual	0	0		
2016	Actual	0	0	OEB-approved	
2017	Actual				
2018	Actual				
2019	Forecast				
2020	Forecast				
2021	Forecast	0	0		
2022	Forecast	0	0		
2023	Forecast	0	0		
2024	Forecast	0	0		
2025	Forecast	0	0		

Variance Analysis	Year	Revenues Year-over-year	Test Year Versus OEB-approved	Demand Year-over-year	Test Year Versus OEB-approved	Demand per Customer Year-over-year	Test Year Versus OEB-approved
Historical	2015						
Historical	2016	2.4%					
Historical	2017	-0.9%					
Historical	2018	-29.0%					
Bridge Year	2019	64.8%					
Bridge Year	2020	1.9%					
Test Year	2021	-8.1%					
Test Year	2022	8.3%					
Test Year	2023	5.2%					
Test Year	2024	3.8%					
Test Year	2025	2.7%					
	Geometric Mean	3.4%					

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**		
Historical	*2015*	Actual		
Historical	*2016*	Actual		OEB-approved
Historical	*2017*	Actual		
Historical	*2018*	Actual		
Bridge Year	*2019*	Forecast		
Bridge Year	*2020*	Forecast		
Test Year	*2021*	Forecast		
Test Year	*2022*	Forecast		
Test Year	*2023*	Forecast		
Test Year	*2024*	Forecast		
Test Year	*2025*	Forecast		

Consumption (kWh) (3)				
	Actual (Weather actual)	**Weather-normalized**		**Weather-normalized**
Actual				
Actual			OEB-approved	
Actual				
Actual				
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				

Consumption (kWh) per Customer				
	Actual (Weather actual)	**Weather-normalized**		**Weather-normalized**
Actual				
Actual			OEB-approved	
Actual				
Actual				
Forecast				
Forecast				
Forecast				
Forecast				
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**		
Historical	*2015*	Actual		
Historical	*2016*	Actual		
Historical	*2017*	Actual		
Historical	*2018*	Actual		
Bridge Year	*2019*	Forecast		
Bridge Year	*2020*	Forecast		
Test Year	*2021*	Forecast		
Test Year	*2022*	Forecast		
Test Year	*2023*	Forecast		
Test Year	*2024*	Forecast		
Test Year	*2025*	Forecast		

Demand (kW)				
	Actual (Weather actual)	**Weather-normalized**		**Weather-normalized**
Actual				
Actual				
Actual				
Actual				
Forecast				
Forecast			OEB-approved	
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				

Demand (kW) per Customer				
	Actual (Weather actual)	**Weather-normalized**		**Weather-normalized**
Actual				
Actual				
Actual				
Actual				
Forecast				
Forecast			OEB-approved	
Forecast				
Forecast				
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)? kWh

	Calendar Year (for 2021 Cost of Service	Customers		
Historical	2015	Actual		
Historical	2016	Actual		OEB-approved
Historical	2017	Actual		
Historical	2018	Actual		
Bridge Year	2019	Forecast		
Bridge Year	2020	Forecast		
Test Year	2021	Forecast		
Test Year	2022	Forecast		
Test Year	2023	Forecast		
Test Year	2024	Forecast		
Test Year	2025	Forecast		

Consumption (kWh) (3)				
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual				
Actual			OEB-approved	
Actual				
Actual				
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				

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

Demand (kWh)				
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual				
Actual			OEB-approved	
Actual				
Actual				
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				
Forecast				

Demand (kWh) per Customer				
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual				
Actual			OEB-approved	
Actual				
Actual				
Forecast				
Forecast				
Forecast				
Forecast				
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		

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	0.00	0.00	0.00	0.00	0.00	**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-I 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**	
2006 to 2017 OPA CDM programs: Persistence to 2020.	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****	
Weight Factor for each year's CDM program impact on 2020 load forecast	**0**	**0**	**0**	**0.5**	**1**	**0.5**	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Full year impact of 2015 CDM is assumed to be reflected in the base forecast, as the full year persistence of 2015 CDM programs is in the 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
Amount used for CDM threshold for LRAMVA (2020)	77,765,005.00	89,950,886.00	108,371,102.00	55,983,898.00	46,758,492.00	105,210,396.00	**484,039,779.00**
Manual Adjustment for 2020 Load Forecast (billed basis)	-	-	-	27,991,949.00	46,758,492.00	52,605,198.00	127,355,639.00
Manual Adjustment for 2020 LDC-only CDM programs (billed basis)							
Total Manual Forecast to Load Forecast	-	-	-	27,991,949.00	46,758,492.00	52,605,198.00	**127,355,639.00**
Proposed Loss Factor (TLF)	3.35%	Format: X.XX%					
Manual Adjustment for 2020 Load Forecast (system purchased basis)	-	-	-	28,929,679.29	48,324,901.48	54,367,472.13	**131,622,052.91**

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:

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January 2020

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4 APPENDIX A: MODEL STATISTICS **32**

1 Overview

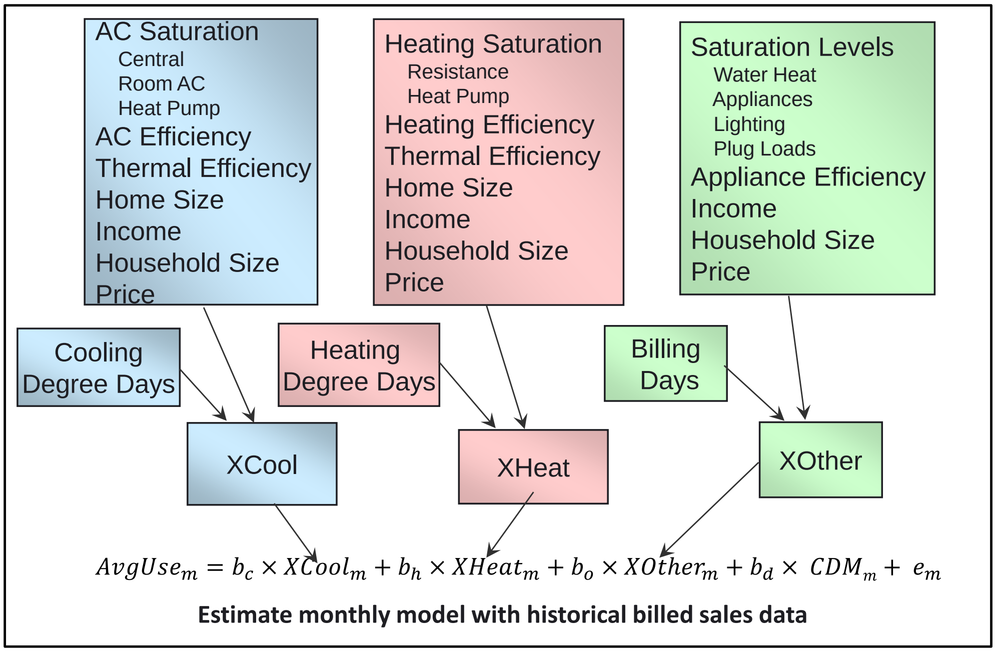
Itron, Inc. recently completed the 2020 to 2025 Hydro Ottawa sales and energy forecast. The forecast is based on actual sales, customer, and purchase data through December 2019. Forecasts are derived for rate class sales, customers, billing demands, system purchases and system peak demand. This document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

Hydro Ottawa serves approximately 311,500 residential customers and 28,300 nonresidential customers. Total 2019 sales equaled 7,244 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) 23% of sales; Street lighting, municipal, and DCL account for remaining sales.

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

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

Figure 1: Residential SAE Model Framework



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

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

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

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

Table 1: Rate Class Forecast

Class Sales Forecast (MWh)										
Year	Res	GS 50	GS 1000	GS I 50-1000kW	GS 1000-1500kw	GS 1500-5000kw	Large Users	Street Lght	MU	DCL
2013	2,256,550	720,479	1,556,240	1,106,483	343,408	857,549	613,514	44,769	17,055	3,408
2014	2,241,046	714,942	1,472,036	1,120,521	333,081	872,269	607,321	44,363	16,412	3,516
2015	2,242,518	723,756	1,392,724	1,181,621	374,915	867,663	564,803	45,150	15,996	3,492
2016	2,260,337	733,312	1,328,250	1,208,310	385,290	805,584	588,874	45,206	15,659	3,546
2017	2,188,889	712,368	1,259,105	1,214,651	399,392	753,194	606,155	38,204	15,231	3,630
2018	2,318,157	727,990	1,255,926	1,256,091	426,659	723,850	608,578	31,723	14,861	3,936
2019	2,263,788	724,602	1,185,849	1,305,564	392,966	723,102	602,082	26,728	14,550	4,923
2020	2,254,563	707,799	1,129,931	1,323,199	386,743	701,795	588,828	24,064	14,106	4,992
2021	2,253,081	700,163	1,080,341	1,353,381	385,754	682,977	574,292	22,107	13,602	4,992
2022	2,273,964	699,456	1,041,565	1,396,553	386,993	682,362	572,889	21,225	13,130	4,992
2023	2,299,513	697,989	1,002,911	1,440,200	388,279	682,571	572,033	20,413	12,663	4,992
2024	2,333,345	698,161	966,522	1,487,344	390,553	684,488	572,834	19,603	12,195	4,992
2025	2,353,299	696,245	925,376	1,528,486	391,592	683,614	570,390	18,854	11,728	4,992

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

Table 2: System Forecast

Year	Total Sales (MWh)	chg	System Purchases (MWh)	chg	Peak Demand (MW)	chg
2013	7,519,455		7,722,174		1,427	
2014	7,425,507	-1.2%	7,636,154	-1.1%	1,304	-8.7%
2015	7,412,638	-0.2%	7,622,795	-0.2%	1,392	6.8%
2016	7,374,368	-0.5%	7,600,821	-0.3%	1,407	1.1%
2017	7,190,819	-2.5%	7,410,782	-2.5%	1,369	-2.7%
2018	7,367,771	2.5%	7,612,657	2.7%	1,482	8.2%
2019	7,244,154	-1.7%	7,461,870	-2.0%	1,398	-5.6%
2020	7,136,020	-1.5%	7,355,364	-1.4%	1,458	4.3%
2021	7,070,690	-0.9%	7,288,050	-0.9%	1,452	-0.4%
2022	7,093,129	0.3%	7,311,171	0.3%	1,461	0.6%
2023	7,121,564	0.4%	7,340,477	0.4%	1,468	0.5%
2024	7,170,037	0.7%	7,390,403	0.7%	1,480	0.8%
2025	7,184,576	0.2%	7,405,423	0.2%	1,488	0.5%
2013-19		-0.6%		-0.6%		-0.2%
2020-25		0.1%		0.1%		0.4%

2 Forecast Data and Assumptions

2.1 Historical Class Sales and Energy Data

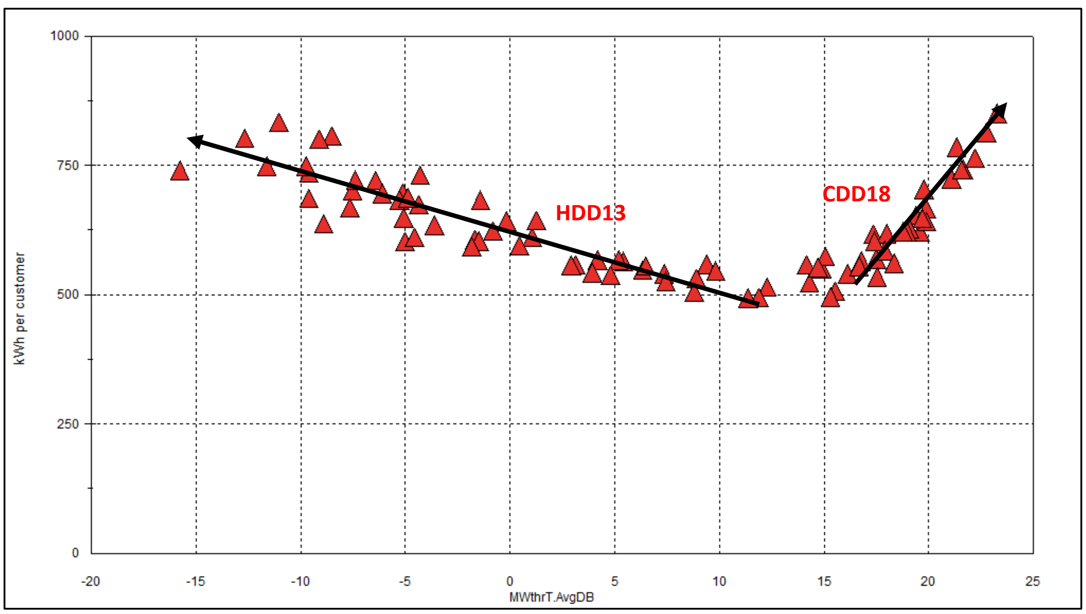
Rate class linear regression models are estimated using monthly billed sales and customer data from January 2013 through December 2019. Prior to 2013 the monthly billed sales data is a poor measure of what was actually used during the calendar month; unbilled sales estimates were significantly improved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

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

2.2 Weather Data

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

Figure 2: Residential Average Use vs Monthly Average Temperature



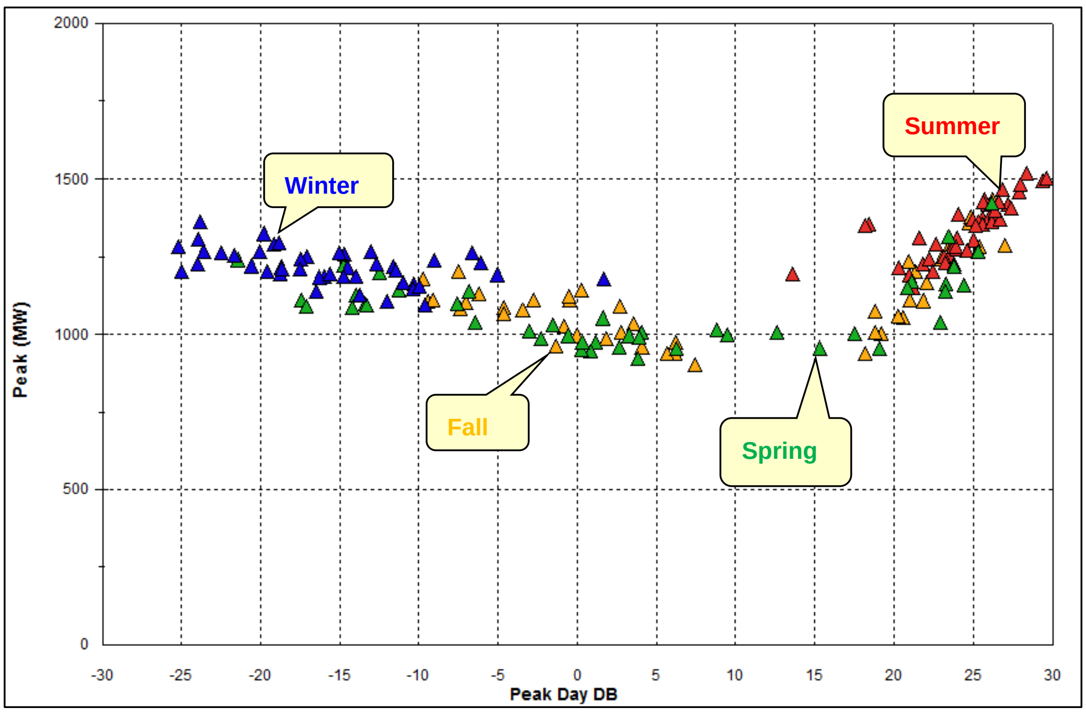
Normal monthly degree-days are calculated as an average of monthly degree-days over the past twenty years – 1999 through 2018.

Peak-Day Weather Variables

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

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

Figure 3: Monthly Peak Demand /Temperature Relationship



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

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

2.3 Economic Data

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

Table 3: Ottawa Regional Economic Forecast

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

2.4 Appliance Saturation and Efficiency Trends

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

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

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

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

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

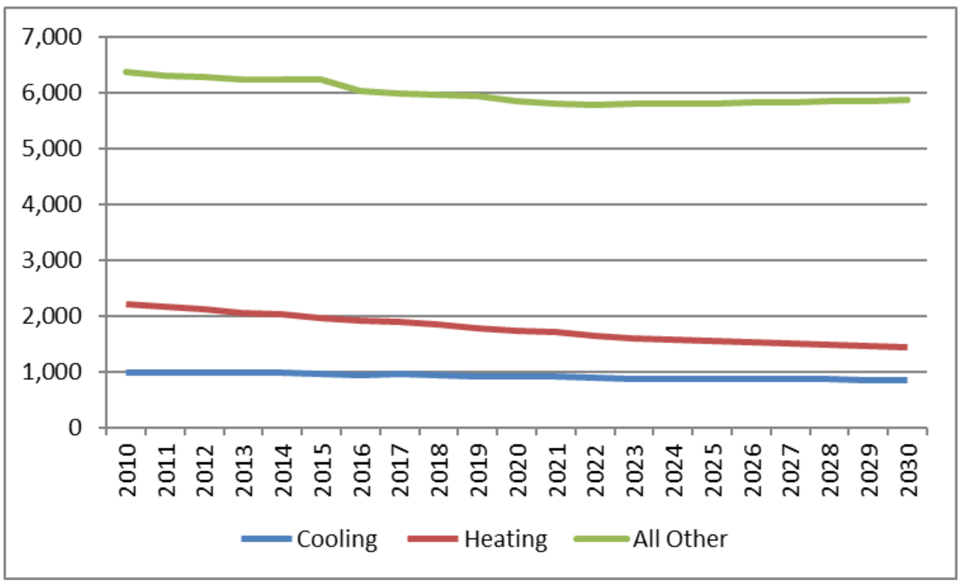
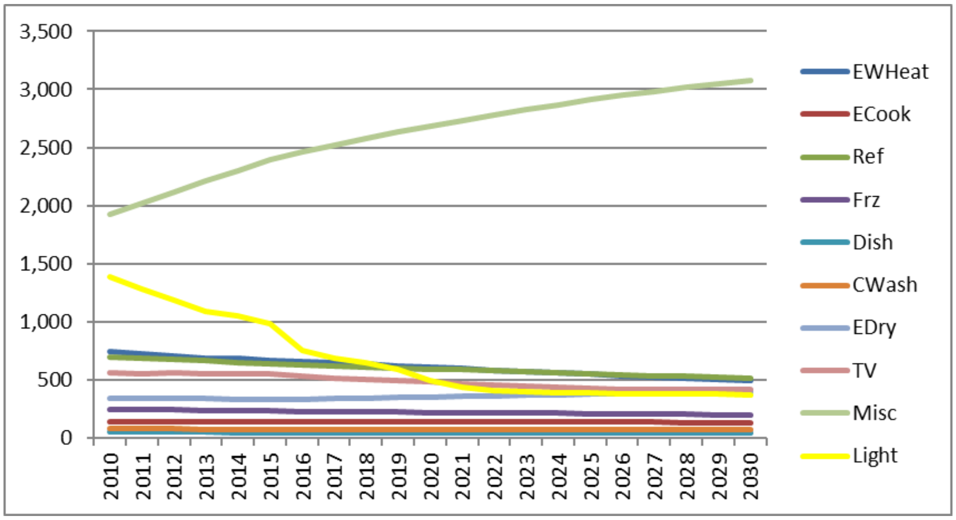


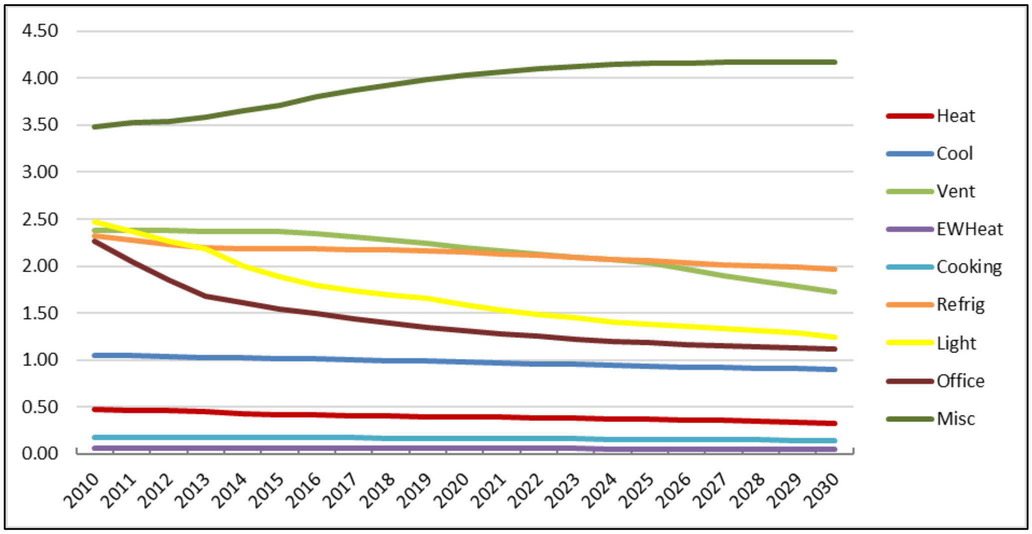
Figure 5: Residential Other Use Energy Intensities (kWh per HH)



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

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

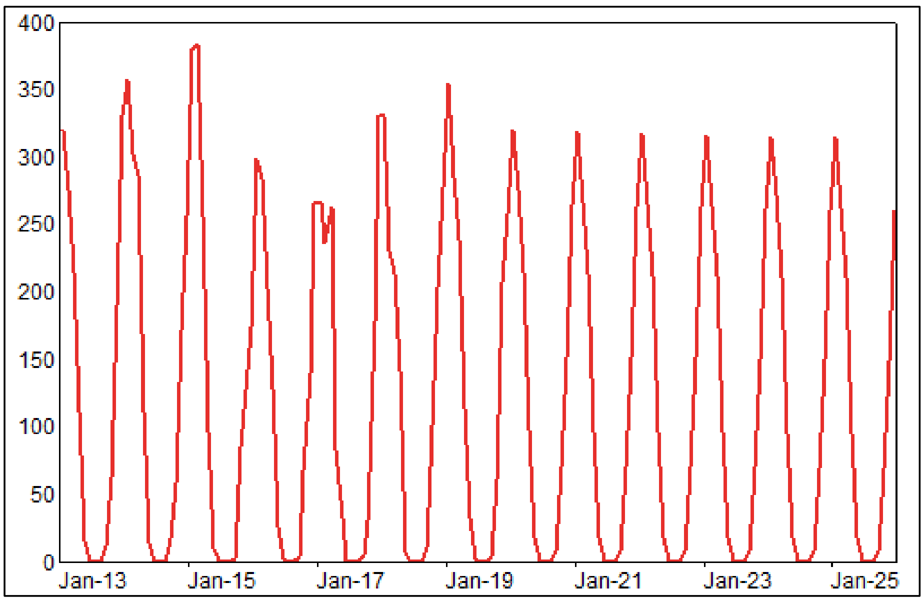
Where

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

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

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

Figure 7: Residential XHeat Variable



XCool is derived in a similar manner:

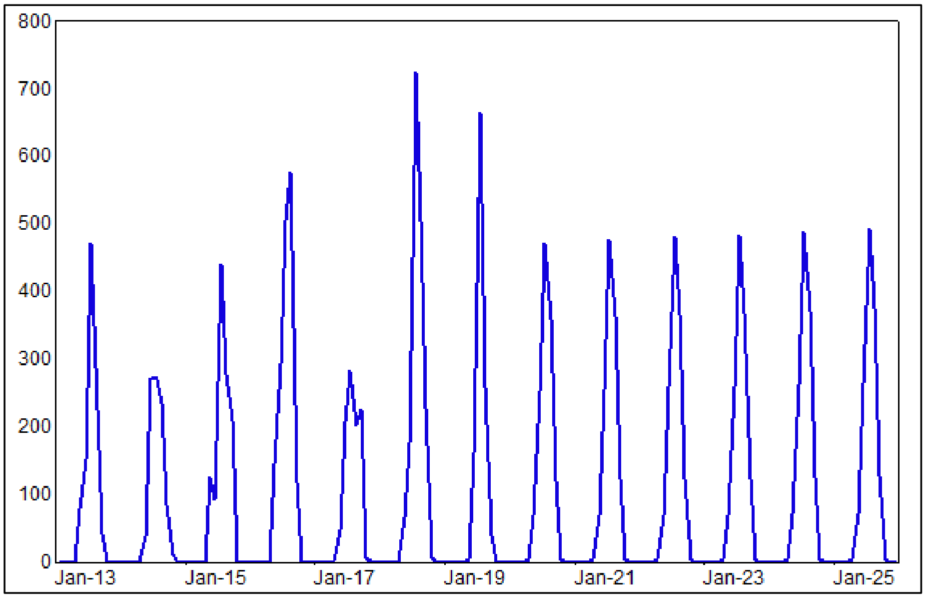
$XCool_m = CDDIdx_m \ x \ IncIdx^{0.15}{}_m \ x \ CoolIntensity_a$

Where

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

Figure 8 shows the calculated XCool variable.

Figure 8: Residential XCool Variable



XOther captures non-weather sensitive end-use

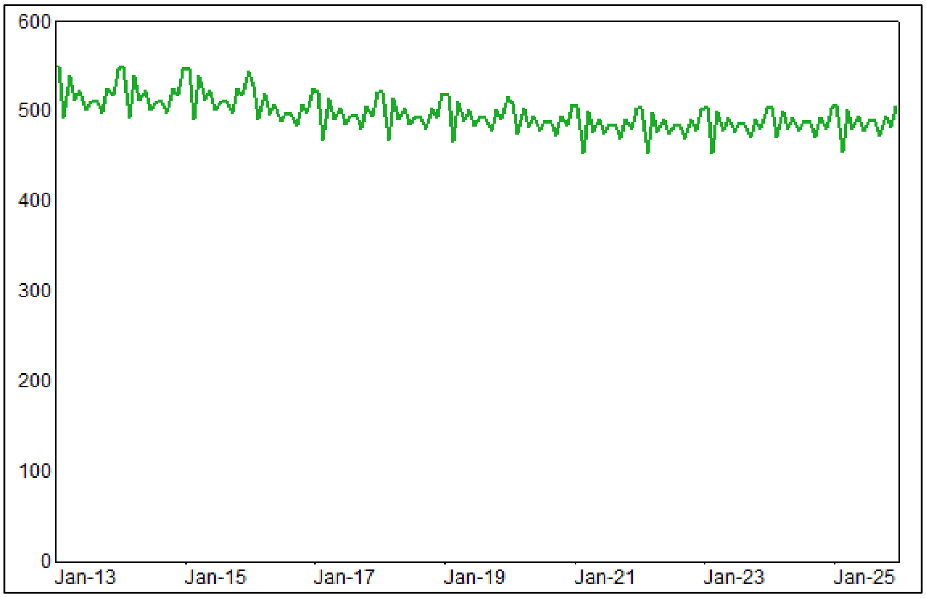
$XOther_m = DaysIdx_m \times IncIdx^{0.15}{}_m \times OtherIntensity_a \times MonthlyMultiplier_m$

Where

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

Figure 9 shows the calculated XOther variable.

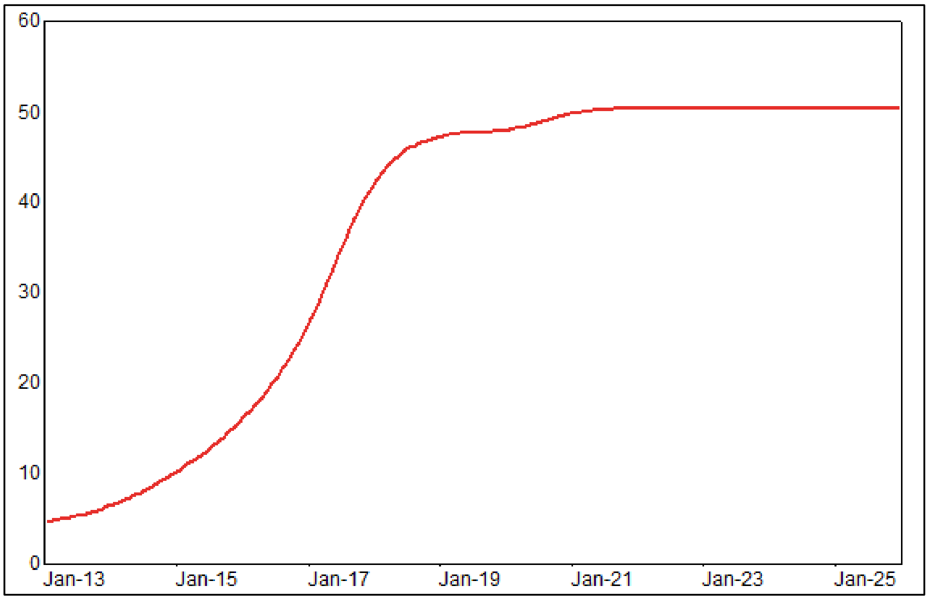
Figure 9: Residential XOther Variable



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

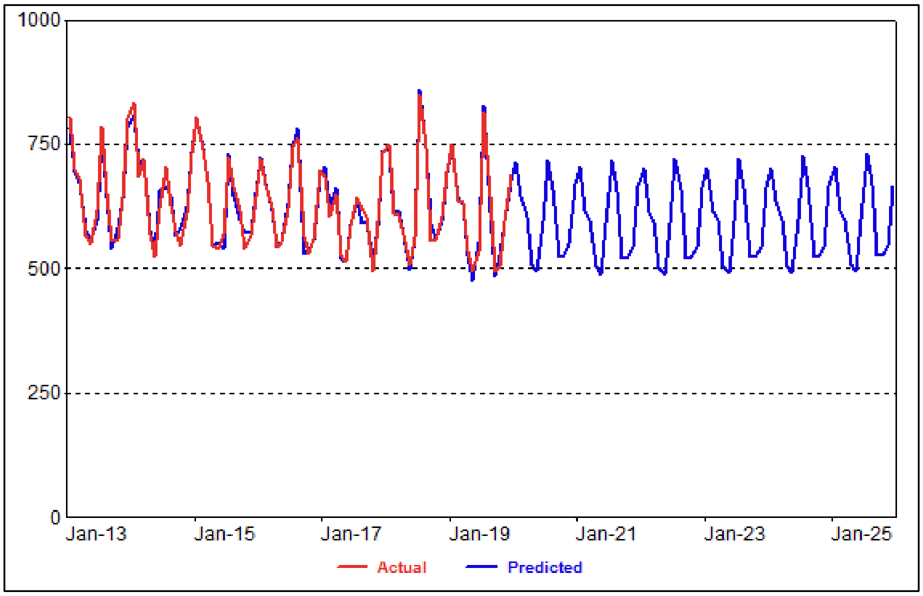
Cumulative CDM starts in 2013 at an estimated average per customer 5 kWh per month (60 kWh per year) and increases to 48 kWh per month (576 kWh per year) by 2019. Projected CDM growth slows considerably after 2019 reaching 50 kWh per month by 2021. Figure 10 shows the residential per customer CDM projections.

Figure 10: Residential Per Customer CDM



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

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

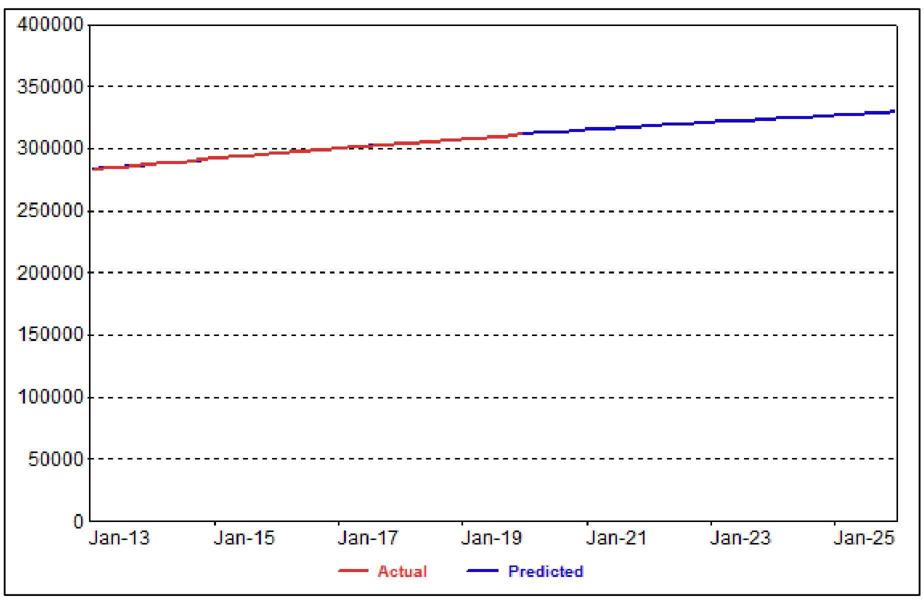


The estimated model explains historical sales well with an Adjusted R-Squared of 0.96 and a mean absolute percent error (MAPE) of 2.0%. The model variables are all strongly statistically significant. The model also includes binary variables for March, April, May, and November and shifts in usage in 2015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

Customer Forecast

The customer forecast is based on a monthly regression model that relates number of customers to population projections; the correlation between number of customers and population is extremely high at 0.98. Monthly binaries are included to capture small variation in monthly customer counts. Figure 12 shows actual and predicted customers.

Figure 12: Actual and Predicted Residential Customer



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

Sales Forecast

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

Table 5: Residential Forecast

Residential Forecast						
Year	Average Use (kWh)	chg	Customers	chg	Sales (MWh)	chg
2013	7,919		284,964		2,256,550	
2014	7,744	-2.2%	289,385	1.6%	2,241,046	-0.7%
2015	7,631	-1.5%	293,884	1.6%	2,242,518	0.1%
2016	7,585	-0.6%	298,001	1.4%	2,260,336	0.8%
2017	7,252	-4.4%	301,839	1.3%	2,188,889	-3.2%
2018	7,591	4.7%	305,390	1.2%	2,318,157	5.9%
2019	7,322	-3.5%	309,165	1.2%	2,263,790	-2.3%
2020	7,200	-1.7%	313,134	1.3%	2,254,563	-0.4%
2021	7,122	-1.1%	316,346	1.0%	2,253,082	-0.1%
2022	7,120	0.0%	319,386	1.0%	2,273,965	0.9%
2023	7,135	0.2%	322,306	0.9%	2,299,512	1.1%
2024	7,176	0.6%	325,150	0.9%	2,333,345	1.5%
2025	7,175	0.0%	327,975	0.9%	2,353,298	0.9%
2013-19		-1.3%		1.4%		0.1%
2020-25		-0.1%		0.9%		0.9%

3.1.2 Commercial Forecast Models

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

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

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

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

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

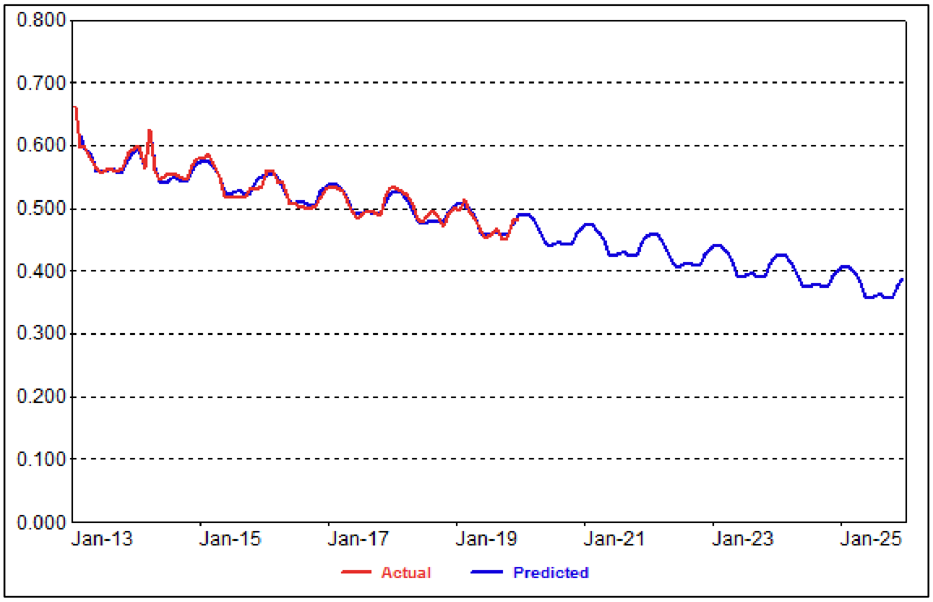
- $SmlEconVar_m = Pop_m^{0.5} \times GDP_m^{0.5}$
- $LrgEconVar_m = Pop_m^{0.2} \times GDP_m^{0.8}$

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

Commercial sales models are estimated over the period January 2013 to December 2019. The model in-sample fits are relatively strong with Adjusted R-Squared ranging from 0.89 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 and GS5000, CDM adjustments are made by subtracting future CDM savings from the model predicted results.

Figure 14: Actual and Predicted GS50 Sales (MWh)

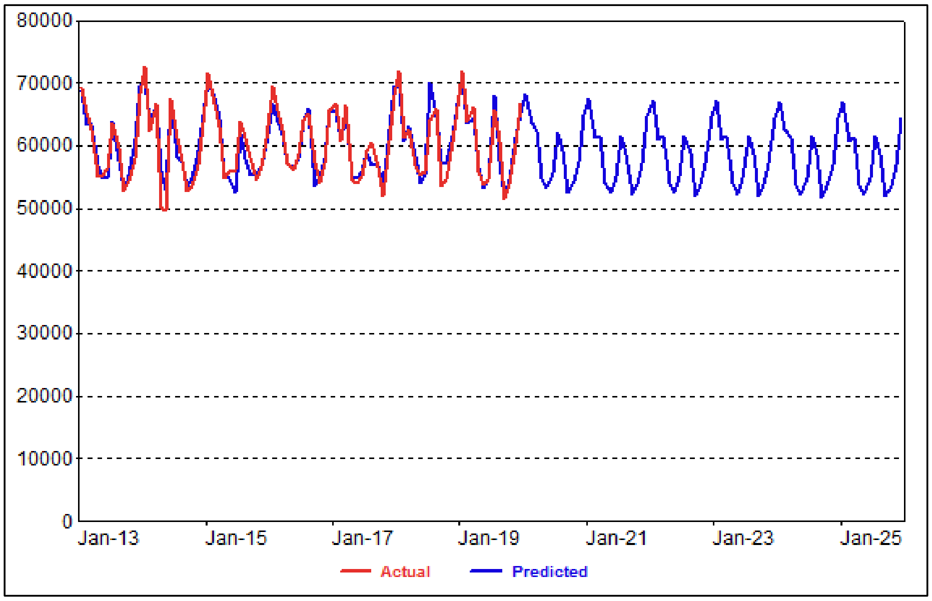


Figure 15: Actual and Predicted GS1000 Sales (MWh)

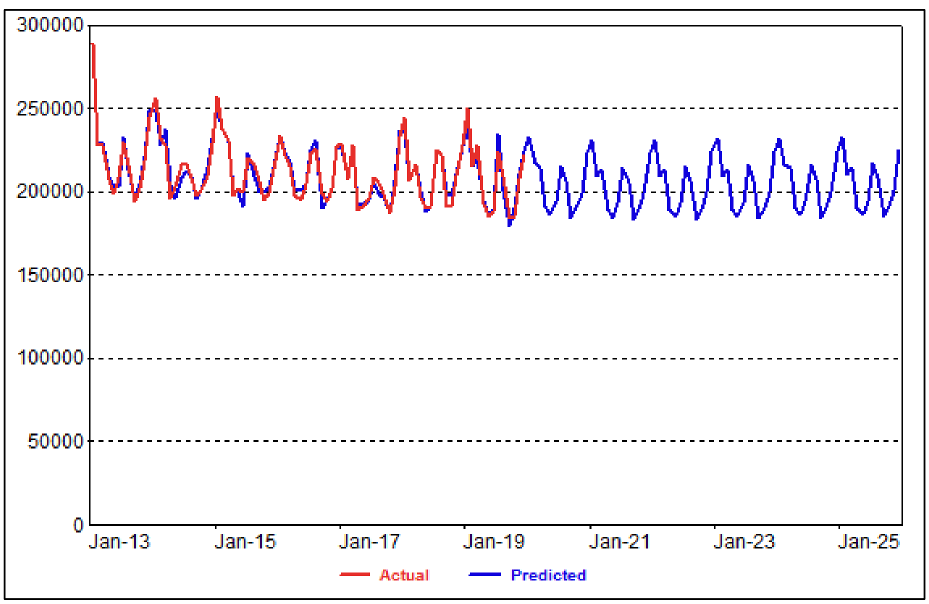
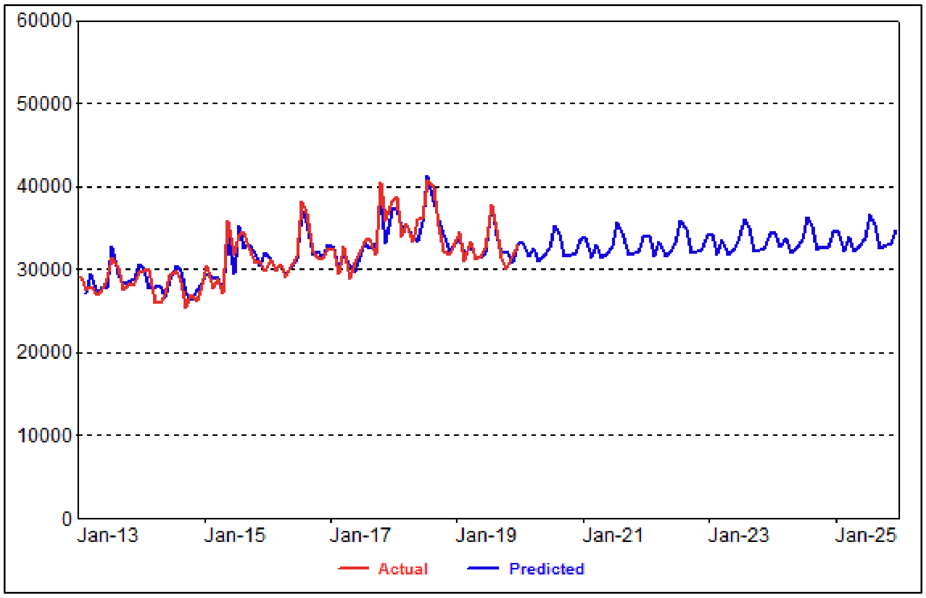
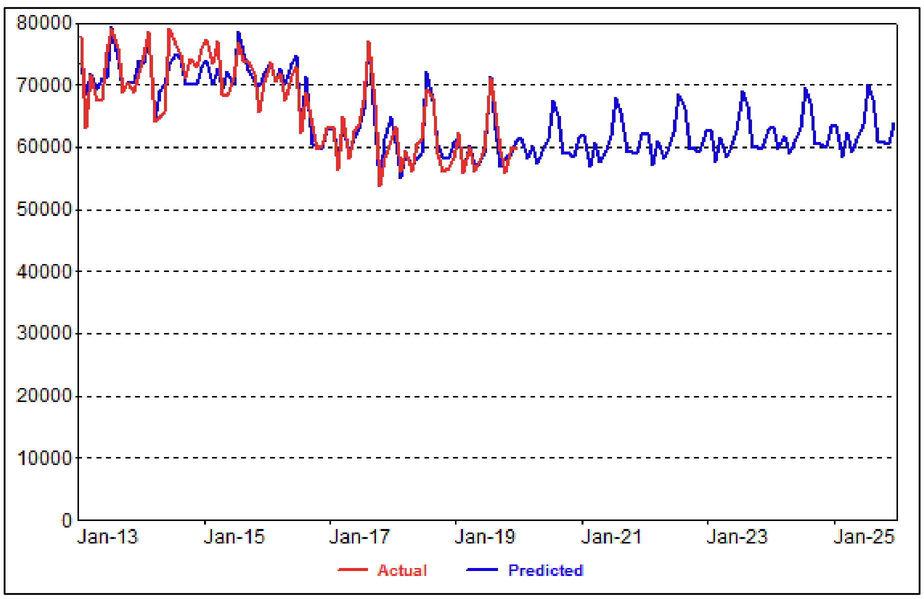


Figure 16: Actual and Predicted GS1500 Sales (MWh)



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

Figure 17: Actual and Predicted GS5000 Sales (MWh)



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

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

Table 6: Commercial Sales Forecast

Class Sales Forecast (MWh)								
Year	GS 50	chg	GS 1000	chg	GS 1500	chg	GS 5000	chg
2013	720,479		2,662,723		343,408		857,549	
2014	714,942	-0.8%	2,592,557	-2.6%	333,081	-3.0%	872,269	1.7%
2015	723,756	1.2%	2,574,345	-0.7%	374,915	12.6%	867,663	-0.5%
2016	733,312	1.3%	2,536,560	-1.5%	385,290	2.8%	805,584	-7.2%
2017	712,368	-2.9%	2,473,756	-2.5%	399,392	3.7%	753,194	-6.5%
2018	727,990	2.2%	2,512,017	1.5%	426,659	6.8%	723,850	-3.9%
2019	724,602	-0.5%	2,491,413	-0.8%	392,966	-7.9%	723,102	-0.1%
2020	707,799	-2.3%	2,453,130	-1.5%	386,743	-1.6%	701,795	-2.9%
2021	700,163	-1.1%	2,433,722	-0.8%	385,754	-0.3%	682,977	-2.7%
2022	699,456	-0.1%	2,438,118	0.2%	386,993	0.3%	682,362	-0.1%
2023	697,989	-0.2%	2,443,111	0.2%	388,279	0.3%	682,571	0.0%
2024	698,161	0.0%	2,453,866	0.4%	390,553	0.6%	684,488	0.3%
2025	696,245	-0.3%	2,453,862	0.0%	391,592	0.3%	683,614	-0.1%
2013-19		0.1%		-1.1%		2.5%		-2.7%
2020-25		-0.3%		0.0%		0.2%		-0.5%

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

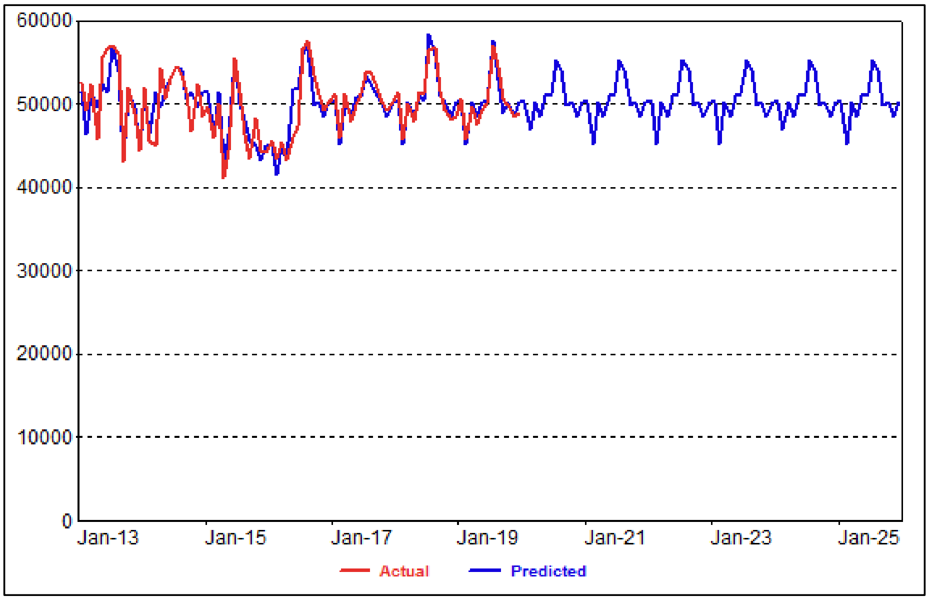
Table 7: Commercial Customer Forecast

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

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

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

Figure 18: Actual and Predicted Large Users (MWh)



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

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

Figure 19: Actual and Predicted Street Light (MWh)

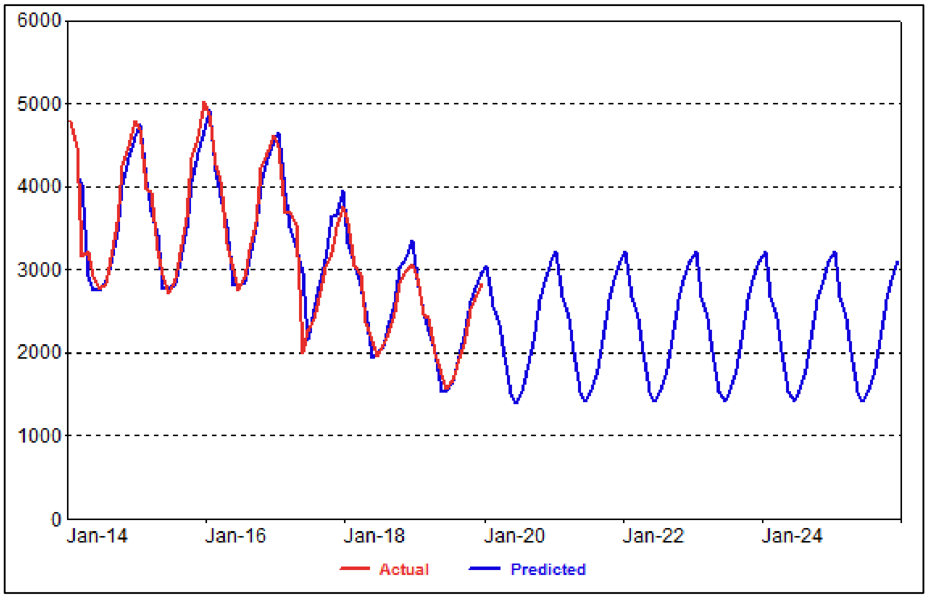
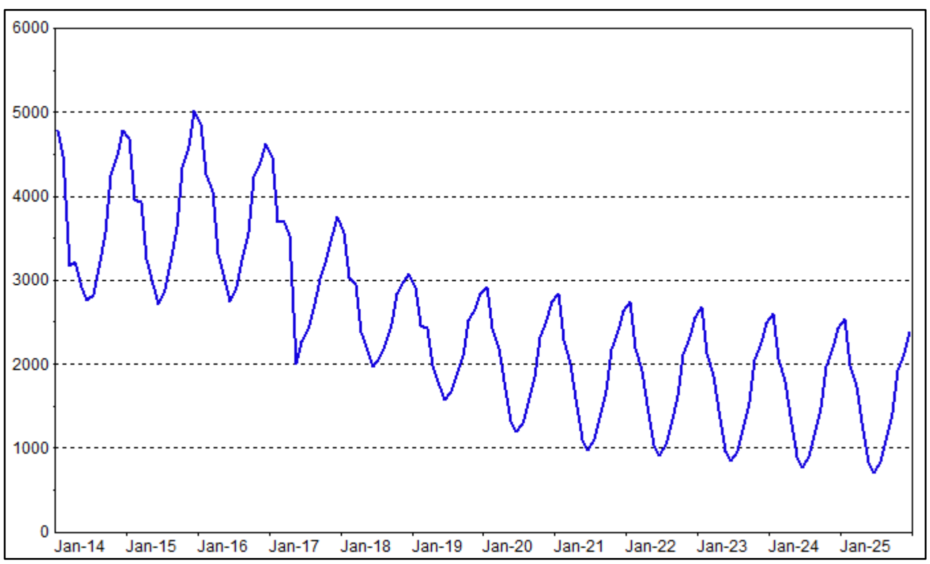


Figure 20: Street Light CDM Adjusted



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

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3.1.4 Billing Demand Forecast

Several rate 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 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	274,439	-4.8%	285,471	-1.2%	77,147	-5.1%	142,573	-8.5%	100,489	-3.3%	5,873	-11.1%
2021	264,739	-3.5%	291,428	2.1%	77,120	0.0%	139,935	-1.9%	98,814	-1.7%	5,313	-9.5%
2022	257,192	-2.9%	299,263	2.7%	77,407	0.4%	140,103	0.1%	98,706	-0.1%	4,991	-6.1%
2023	249,765	-2.9%	307,067	2.6%	77,676	0.3%	140,250	0.1%	98,597	-0.1%	4,804	-3.7%
2024	242,253	-3.0%	314,934	2.6%	77,984	0.4%	140,417	0.1%	98,489	-0.1%	4,617	-3.9%
2025	235,510	-2.8%	322,933	2.5%	78,354	0.5%	140,650	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.

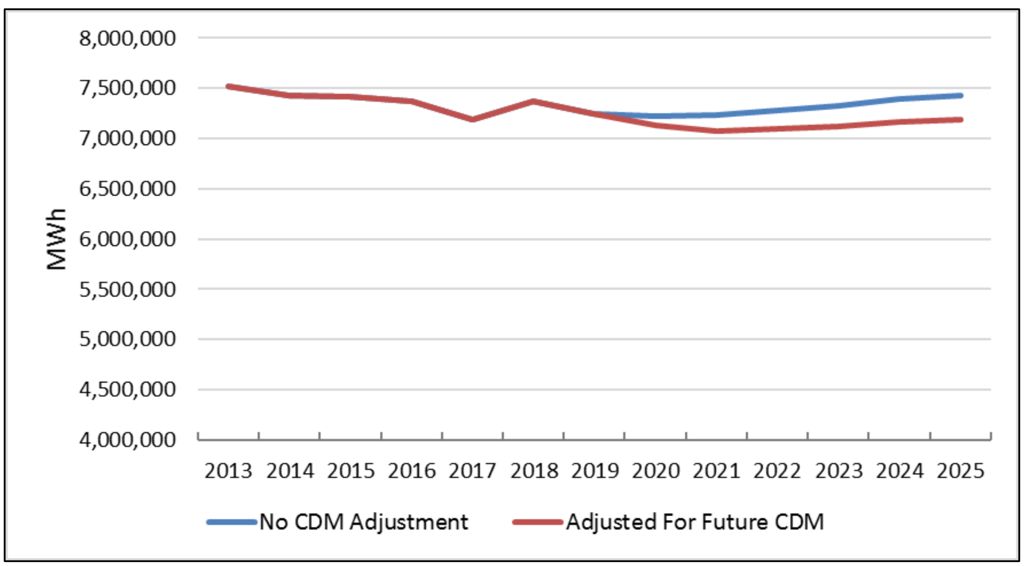
There are two reasons to include CDM as a model variable. First, adding CDM helps explain the declining customer usage and as a result improves on the model fit statistics. Second, it helps avoid double-counting savings. The SAE models already have strong efficiency built into the heating, cooling, and 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 -0.696. This implies that 30% of the CDM savings is already accounted for in the end-use intensity trends and estimated coefficients on the heating, cooling, and base-use variables. For the forecast period, 70 percent of future DSM savings will flow into the model-based forecast. In the small commercial model, the coefficient on CDM is -1.041 and -1.143 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 historical relationship between purchases and sales between January 2015 and

December 2019. While there is some small monthly variation, the average adjustment factor is 1.03; the sales forecast is adjusted up three percent.

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

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

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

Heating and Cooling Model Variables

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

$HeatVar_m = HeatLoad_m \times PkHDD_m$
Heatload is derived from the rate class sales forecast models as the product of the coefficient of the XHeat variable times XHeat for normal weather conditions:

$HeatLoad_m = B_1 \times NrmXHeat_m$

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

$CoolVar_m = CoolLoad_m \times PkTDD_m$

Where

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

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

Figure 22: Peak XHeat Variable

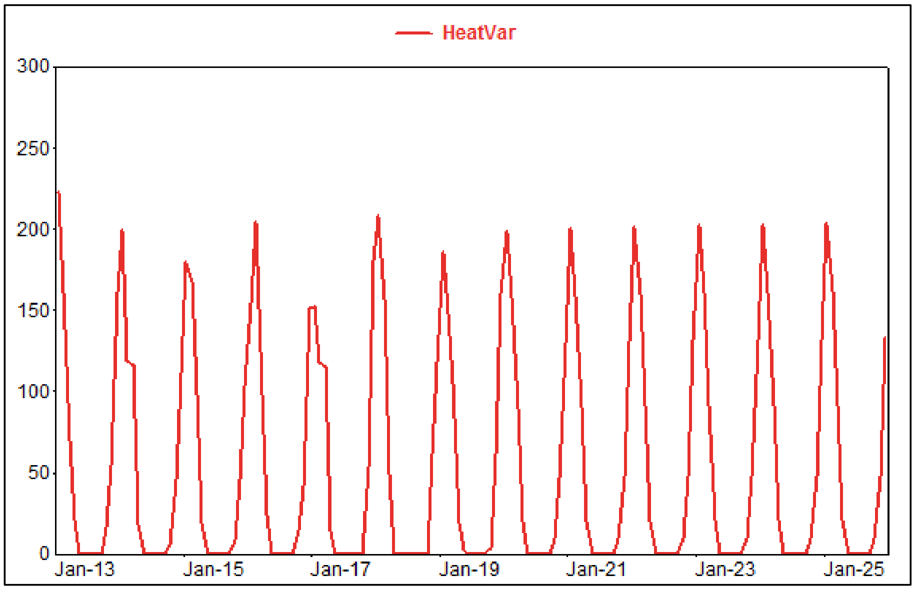
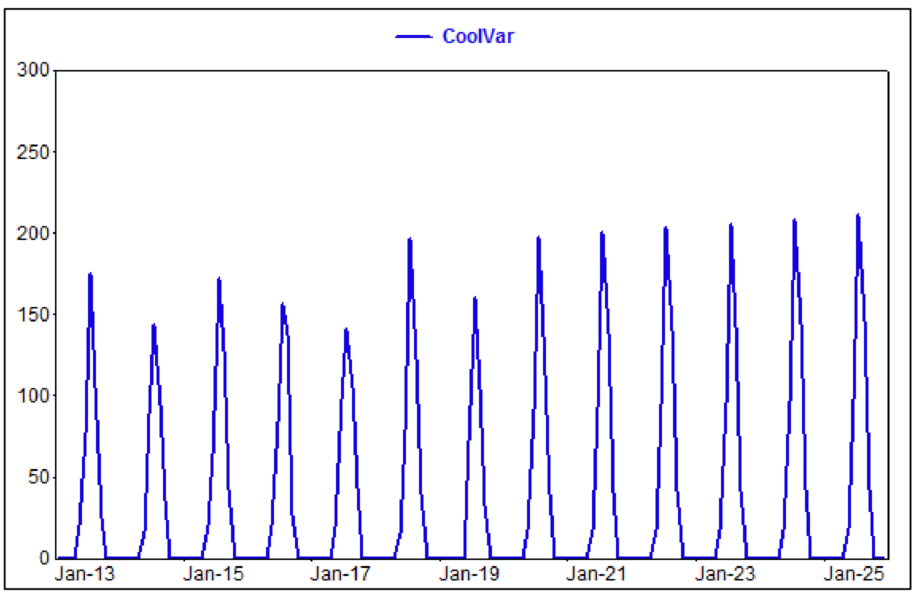


Figure 23: Peak XCool Variable



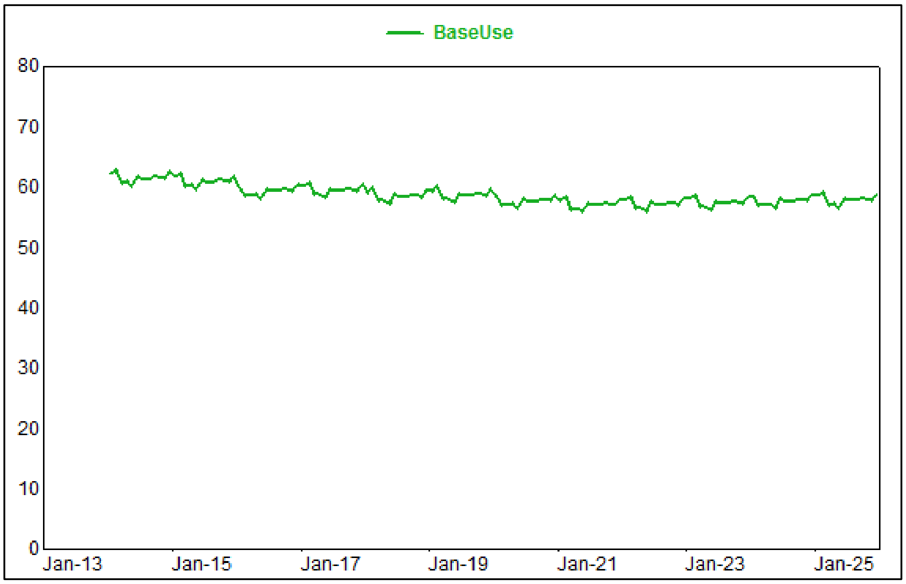
BaseVar Model Variable

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

$BaseVar_m = WNSales_m – HeatLoad_m - CoolLoad_m$

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

Figure 24: Peak Base Variable



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

Figure 25: Actual and Predicted Peak Model (MW)

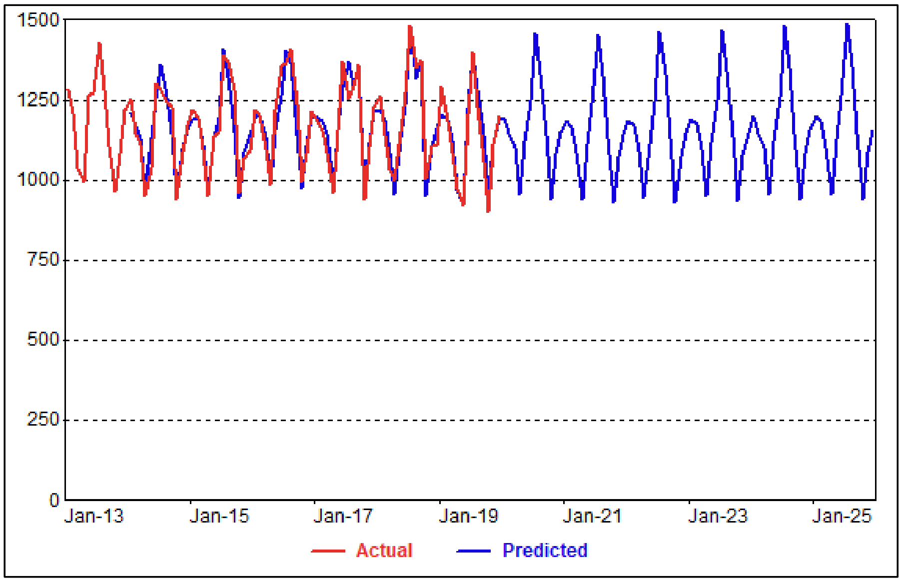


Table 9 shows system purchase and peak demand forecast.

Table 9: System Forecast

Year	System Purchases (MWh)	chg	Peak Demand (MW)	chg
2013	7,722,175		1,427	
2014	7,636,154	-1.1%	1,304	-8.7%
2015	7,622,794	-0.2%	1,392	6.8%
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%	1,482	8.2%
2019	7,461,870	-2.0%	1,398	-5.6%
2020	7,355,366	-1.4%	1,458	4.3%
2021	7,288,050	-0.9%	1,452	-0.4%
2022	7,311,171	0.3%	1,461	0.6%
2023	7,340,476	0.4%	1,468	0.5%
2024	7,390,403	0.7%	1,480	0.8%
2025	7,405,423	0.2%	1,488	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	56.27	0.00%
mPkVars.HeatVar	0.65	0.14	4.65	0.00%
mPkVars.CoolVar	2.07	0.17	12.26	0.00%
mBin.Yr2016Plus	49.98	12.33	4.05	0.01%
mBin.Apr	-102.34	25.48	-4.02	0.02%
mBin.May	53.24	26.63	2.00	5.00%
mBin.Oct	-123.12	26.43	-4.66	0.00%
mBin.Sep17	182.12	51.30	3.55	0.07%
mBin.Sep18	223.63	51.33	4.36	0.01%
mBin.May19	-180.87	54.60	-3.31	0.15%

Model Statistics	
Adjusted Observations	72
Deg. of Freedom for Error	62
Adjusted R-Squared	0.873
Model Sum of Squares	1,217,516.51
Sum of Squared Errors	152,214.28
Mean Squared Error	2,455.07
Std. Error of Regression	49.55
Mean Abs. Dev. (MAD)	34.26
Mean Abs. % Err. (MAPE)	2.92%
Durbin-Watson Statistic	1.921

Residential Avg Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRev.XHeatRes_Avg	0.68	0.0	32.18	0.00%
mStructRev.XCoolRes_Avg	0.52	0.0	33.44	0.00%
mStructRev.XOtherRes_Av	1.03	0.0	90.33	0.00%
mBin.Mar	-30.06	7.2	-4.21	0.01%
mBin.Apr	-24.44	7.2	-3.40	0.11%
mBin.May	-33.45	7.5	-4.47	0.00%
mBin.Nov	-21.07	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	-5.92	0.00%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	74
Adjusted R-Squared	0.964
Model Sum of Squares	652,186
Sum of Squared Errors	21,538
Mean Squared Error	291
Std. Error of Regression	17.06
Mean Abs. Dev. (MAD)	12.43
Mean Abs. % Err. (MAPE)	2.03%
Durbin-Watson Statistic	2.227

Residential Customer Model

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

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

GS 50 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	20332.62	7272.8	2.80	0.65%
mStructRev.XOtherGS50	2600.26	609.8	4.26	0.01%
mStructRev.XHeatGS50	181482.05	7417.7	24.47	0.00%
mStructRev.XCoolGS50	23328.83	1511.6	15.43	0.00%
mBin.Jun14	10464.87	2006.6	5.22	0.00%
CDM.GS50	-1.05	0.4	-2.79	0.67%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	78
Adjusted R-Squared	0.881
Model Sum of Squares	2,383,678,415
Sum of Squared Errors	298,887,461
Mean Squared Error	3,831,891
Std. Error of Regression	1957.52
Mean Abs. Dev. (MAD)	1415.03
Mean Abs. % Err. (MAPE)	2.38%
Durbin-Watson Statistic	1.705

GS 50 Customer Model

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

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

GS 1000 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	78509.97	17577.95	4.47	0.00%
mStructRev.XOtherGS1000	9779.33	1474.86	6.63	0.00%
mStructRev.XHeatGS1000	562876.92	18274.45	30.80	0.00%
mStructRev.XCoolGS1000	75637.03	3974.84	19.03	0.00%
mBin.Jan13	41084.83	4930.51	8.33	0.00%
mBin.Jul18	-15323.35	5301.13	-2.89	0.50%
CDM.GS1000	-1.149	0.101	-11.36	0.00%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	77
Adjusted R-Squared	0.94
Model Sum of Squares	28,697,086,635
Sum of Squared Errors	1,694,229,313
Mean Squared Error	22,002,978
Std. Error of Regression	4690.73
Mean Abs. Dev. (MAD)	3464.48
Mean Abs. % Err. (MAPE)	1.63%
Durbin-Watson Statistic	1.91

GS 1000 NI Share Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.TrendVar	-0.02	0.00	-29.53	0.00%
mBin.Jan	0.58	0.00	171.08	0.00%
mBin.Feb	0.58	0.00	166.16	0.00%
mBin.Mar	0.57	0.00	168.29	0.00%
mBin.Apr	0.56	0.00	178.94	0.00%
mBin.May	0.53	0.00	171.80	0.00%
mBin.Jun	0.532	0.003	170.53	0.00%
mBin.Jul	0.538	0.003	171.68	0.00%
mBin.Aug	0.54	0.003	171.66	0.00%
mBin.Sep	0.537	0.003	169.73	0.00%
mBin.Oct	0.539	0.003	169.66	0.00%
mBin.Nov	0.559	0.003	175.23	0.00%
mBin.Dec	0.57	0.003	177.79	0.00%
mBin.Feb14	-0.027	0.008	-3.26	0.18%
mBin.Mar14	0.046	0.008	5.46	0.00%
AR(1)	0.226	0.094	2.403	1.90%

Model Statistics	
Adjusted Observations	83
Deg. of Freedom for Error	67
Adjusted R-Squared	0.961
Model Sum of Squares	0
Sum of Squared Errors	0
Mean Squared Error	0
Std. Error of Regression	0.01
Mean Abs. Dev. (MAD)	0.01
Mean Abs. % Err. (MAPE)	1.10%
Durbin-Watson Statistic	1.437

GS 1000NI Customer Model

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

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

GS 1000I Customer Model

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

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

GS 1500 Sales Model

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

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

GS 1500 Customer Model

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

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

GS 5000 Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	26002.775	9864.7	2.636	1.02%
mStructRev.XHeatGS5000	45570.225	9549.70	4.77	0.00%
mStructRev.XCoolGS5000	19725.294	1961.49	10.06	0.00%
mStructRev.XOtherGS5000	3466.28	801.09	4.33	0.00%
mBin.Feb14	10062.25	2654.58	3.79	0.03%
mBin.Mar14	-8605.09	2503.13	-3.44	0.10%
mBin.Jul16	-7479.56	2619.69	-2.86	0.56%
mBin.Aug17	12618.30	2549.92	4.95	0.00%
mBin.Oct17	-6874.24	2576.18	-2.67	0.94%
mBin.Jul16Plus	-10853.92	777.47	-13.96	0.00%
mBin.Yr18Plus	-3989.34	852.64	-4.679	0.00%

Model Statistics	
Adjusted Observations	84
Deg. of Freedom for Error	73
Adjusted R-Squared	0.879
Model Sum of Squares	3,660,920,433
Sum of Squared Errors	435,980,661
Mean Squared Error	5,972,338
Std. Error of Regression	2443.84
Mean Abs. Dev. (MAD)	1784.08
Mean Abs. % Err. (MAPE)	2.66%
Durbin-Watson Statistic	1.834

GS 5000 Customer Model

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

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

Large Users Sales Model

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

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

Large Users Customer Model

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

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

Street Lighting Sales Model

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

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

Street Lighting Customer Model

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

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

MU Sales Model

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

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

MU Customer Model

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

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

DCL Sales Model

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

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

LOAD FORECAST

Please refer to the Excel files attached:

- 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

ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSES

1. INTRODUCTION

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

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

2. HISTORICAL ACCURACY OF LOAD FORECAST

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

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

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).
[2] Ontario Energy Board, *Decision and Order*, EB-2015-0004 (December 22, 2015).

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

- Customers / connections
- Historical, actual, and weather-normalized load (kWh)
- Consumption per customer / connection
- Demand (kW)
- Revenue

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

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

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

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

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
TOTAL MWh SALES	**7,440,624**	**7,379,644**	**7,366,004**	**7,364,071**	**7,364,398**

Table 2 provides Hydro Ottawa's actual energy sales by MWh for 2016-2020 and facilitates comparisons with the information presented in Table 1 above.

Table 2 – 2016-2020 Weather-Normalized Actual Sales 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
TOTAL MWh SALES	**7,262,299**	**7,273,222**	**7,185,136**	**7,239,278**	**7,131,075**

Table 3 provides the variance value between the forecast and the actuals shown above in Tables 1 and 2.

Table 3 – Variance in 2016-2020 Forecast vs. Weather-Normalized Actual Sales (MWh)

	2016	2017	2018	2019	2020
Residential	-12,177	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
TOTAL MWh SALES	**-178,325**	**-106,422**	**-180,868**	**-124,793**	**-233,323**

Table 4 provides the percentage change between the forecast and the actuals that is illustrated in Table 3 above.

Table 4 – 2016-2020 Forecast vs. Weather-Normalized 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%
TOTAL MWh SALES	**-2.40%**	**-1.44%**	**-2.46%**	**-1.69%**	**-3.17%**

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

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
TOTAL KW DEMAND SALES	**10,120,153**	**10,029,417**	**9,982,054**	**9,958,001**	**9,948,806**

Table 6 provides Hydro Ottawa's actual demand sales by kW for 2016-2020.

Table 6 – 2016-2020 Weather-Normalized Actual Demand 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
TOTAL KW DEMAND SALES	**9,931,279**	**9,885,845**	**9,701,385**	**9,683,565**	**9,562,808**

Table 7 provides the variance value between the forecast and the actuals, in relation to 2016-2020 demand sales.

Table 7 – Variance in 2016-2020 Forecast vs. 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)
TOTAL KW DEMAND SALES	**(188,874)**	**(143,572)**	**(280,669)**	**(274,436)**	**(385,998)**

Table 8 provides the percentage change between the forecast and the actuals that is illustrated in Table 7 above.

Table 8 – 2016-2020 Forecast vs. Weather-Normalized 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%
TOTAL KW DEMAND SALES	**-1.87%**	**-1.43%**	**-2.81%**	**-2.76%**	**-3.88%**

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

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
TOTAL CUSTOMERS	**325,238**	**329,294**	**333,321**	**337,307**	**341,240**

	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
TOTAL CONNECTIONS	**59,048**	**59,092**	**59,136**	**59,180**	**59,224**

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

Table 10 – 2016-2020 Actual Number of Customers and Connections by Class

	2016	2017	2018	2019	2020
Residential	298,001	301,839	305,390	309,165	313,134
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
TOTAL CUSTOMERS	**325,915**	**329,927**	**333,620**	**337,454**	**341,559**

	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
TOTAL CONNECTIONS	**62,066**	**61,961**	**62,783**	**63,975**	**65,262**

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

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	-	-
TOTAL CUSTOMERS	**677**	**633**	**299**	**147**	**319**

	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)
TOTAL CONNECTIONS	**3,018**	**2,869**	**3,647**	**4,795**	**6,038**

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

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%
TOTAL CUSTOMERS	**0.21%**	**0.19%**	**0.09%**	**0.04%**	**0.09%**

	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%
TOTAL CONNECTIONS	**5.11%**	**4.86%**	**6.17%**	**8.10%**	**10.20%**

Hydro Ottawa has confidence that the variances identified in the foregoing analyses are within 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	2,203,868	2,232,964	2,227,860	2,263,788	2,254,563
GS < 50 kW	724,984	719,547	712,044	724,602	707,799
GS > 50 to 1,499 kW	2,890,997	2,899,049	2,882,228	2,884,379	2,839,873
GS > 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 Lights	47	47	47	47	47
Total mWH Sales	7,262,299	7,273,222	7,185,136	7,239,278	7,131,075

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

	2016	2017	2018	2019	2020
Residential	-12,177	34,705	21,449	48,804	36,935
GS < 50 kW	-1,376	2,651	2,253	20,409	8,055
GS > 50 to 1,499 kW	-63,444	-8,396	6,806	31,786	4,486
GS > 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 Lights	-1	-1	-1	-1	-1
Total mWH Sales	-178,325	-106,422	-180,868	-124,793	-233,323

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%	2.20%	1.67%
GS < 50 kW	-0.19%	0.37%	0.32%	2.90%	1.15%
GS > 50 to 1,499 kW	-2.15%	-0.29%	0.24%	1.11%	0.16%
GS > 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 Lights	-2.08%	-2.08%	-2.08%	-2.08%	-2.08%
Total mWH Sales	-2.40%	-1.44%	-2.46%	-1.69%	-3.17%

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	7,006,074	7,015,544	6,960,266	6,930,957	6,867,852
GS > 1,500 to 4,999 kW	1,729,271	1,648,910	1,547,429	1,572,857	1,552,781
Large User	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 Lights	132	132	132	132	132
Total	9,931,279	9,885,845	9,701,385	9,683,565	9,562,808

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

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

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

	2016	2017	2018	2019	2020
GS > 50 to 1,499 kW	-0.31%	1.55%	1.99%	2.50%	2.33%
GS > 1,500 to 4,999 kW	-6.39%	-12.18%	-19.24%	-19.63%	-22.42%
Large User	-4.56%	-0.43%	-1.20%	-0.94%	-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	-1.87%	-1.43%	-2.81%	-2.76%	-3.88%

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%

OTHER REVENUE SUMMARY

1. INTRODUCTION

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

Table 1 provides a summary of Other Revenue from 2016-2025, along with the associated Uniform System of Accounts (“USofA”).

Table 1 – 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
TOTAL OTHER REVENUE[1]	**$12,354**	**$13,203**	**$13,093**	**$9,422**	**$10,268**	**$10,977**	**$11,013**	**$11,667**	**$12,151**	**$12,457**

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

[1] Totals may not sum due to rounding.

2. SPECIFIC SERVICE CHARGES

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

2.1. SUMMARY OF PROPOSED SSC CHANGES

Changes to Hydro Ottawa's SSCs for the 2021-2025 period are discussed in more detail below. Additional information regarding SSCs can be found in Exhibit 8-7-1: Specific Service Charges and Attachment 8-7-1(A): Proposed and New Specific Service Charge Calculations. Hydro Ottawa is proposing to apply its Custom Price Escalation Factor ("CPEF") of 2.51% to all SSCs for the years 2022-2025.[2] For detail and context on Hydro Ottawa's CPEF, refer to Exhibit 1-1-10: Alignment with the Renewed Regulatory Framework.

2.1.1. Removal of "Account Certificate" Charge

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

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

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

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

2.1.2. Account Set Up/Change of Occupancy Charge

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

2.1.3. Reconnect at Meter after Regular Hours

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

2.1.4. Duplicate Invoices for Previous Billing

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

2.1.5. Interval Meter - Field Reading

This service charge initially included the costs associated with a Hydro Ottawa representative attending to the site of interval-metered customers to obtain a scheduled meter reading. Such site visits would occur, within a reasonable timeframe, in situations in which the phone line was inoperable and the customer had not taken steps to have the phone line fixed.

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

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

2.1.6. Unprocessed Payment Charge

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

2.1.7. Reconnect at Pole - During Regular Hours

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

2.1.8. Special Billing Service

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

2.1.9. Specific Charge to Access Power Poles - Wireline

For the 2016-2020 period, Hydro Ottawa secured approval from the OEB for a utility-specific rate of $53 per pole per year. For the 2021 Test Year, Hydro Ottawa intends to move to the OEB's generic rate of $45.39, consistent with the policy established by the OEB in 2018.[3] The OEB's approved 2020 inflationary factor has been used to increase the provincially approved rate for 2021, and an escalation factor increase of 2.51% per year between 2022 and 2025.

2.1.10. Dry Core Transformer Charge

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

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

2.2. HIGH LEVEL SSC VARIANCE ANALYSIS

2.2.1. 2016 Actual to 2017 Actual

SSC revenues for 2017 were $700K (11%) below 2016 actuals. The main driver was a one-time $549K recognition of miscellaneous revenue in 2016. A contingent liability was booked in relation to a customer payment received prior to a bankruptcy proceeding. This liability was reversed once the provision recognition criteria no longer applied. Further, the introduction of the Disconnection Moratorium for residential customers in 2017 reduced the overall volume of reconnection activity – and by extension, revenues – in 2017 by approximately $130K.

2.2.2. 2017 Actual to 2018 Actual

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

2.2.3. 2018 Actual to 2019 Bridge Year

SSC revenues for 2019 are forecasted to be $157K (3%) below 2018 actuals. The main driver is the removal of the Collection of Account Charge for residential customers, effective July 1, 2019, in compliance with the Phase 1 amendments to the OEB's Customer Service Rules.[4]

2.2.4. 2019 Bridge Year to 2020 Bridge Year

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

2.2.5. 2020 Bridge Year to 2021 Test Year

SSC revenues in 2021 are forecasted to be $0.5M (8%) below the 2020 forecast. The reasons for this reduction are noted in section 2.1 above. The annual increase from 2021-2025 is

[4] Ontario Energy Board, *Notice of Amendments to Codes and a Rule: Amendments to the Distribution System Code, Standard Supply Service Code, Unit Sub-metering Code, and Gas Distribution Access Rule (and Associated Rate Order)*, EB-2017-0183 (March 14, 2019).

primarily due to the escalation factor applied to the rates each year. One exception is wireless pole attachments, where volumes are expected to increase by 200 units on an annual basis out to 2025.

2.3. SSC FORECAST AND VARIANCE ANALYSIS

Each SCC is forecasted based on the rate factored by the estimated volume. Tables 2 and 3 below provide the revenue actuals and forecast for each SSC.

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

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

Specific Service Charge Revenue	Historical Years			Bridge Years	
	2016	2017	2018	2019	2020
Customer Administration					
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
Reconnect at Meter					
Regular Hours	$15	$5	$4	$6	$4
After Regular Hours	$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
Non-Payment of Account					
Collection of Account Charge - No Disconnection	$11	$5	$139	$69	$0
Reconnect at Meter					
Regular Hours	$237	$170	$154	$145	$154
After Regular Hours	$162	$113	$125	$84	$111
Reconnect at Pole					
Regular Hours	$3	$3	$3	$3	$3
After Regular Hours	$1	$1	$1	$0	$1
Other					
Temporary Service - Install and Remove					
Overhead - no transformer	$5	$11	$8	$12	$11
Underground - no transformer	$6	$24	$25	$25	$25
Overhead - with transformer	$6	$12	$9	$6	$9
Specific Access to Power Poles					
Wireline Pole Attachments	$3,218	$3,296	$3,417	$3,356	$3,415
Wireless Pole Attachments	$0	$0	$0	$0	$34
Drycore Transformer Distribution Charge	$23	$27	$32	$42	$46
Energy Resource Facilities Charge	$0	$0	$0	$0	$0
TOTAL[5]	**$6,160**	**$5,490**	**$5,691**	**$5,535**	**$5,555**

[5] Totals may not sum due to rounding.

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

Specific Service Charge Revenue	Test Years				
	2021	2022	2023	2024	2025
Customer Administration					
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
Reconnect at Meter					
Regular Hours	$4	$4	$4	$4	$4
After Regular Hours	$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
Non-Payment of Account					
Collection of Account Charge - No Disconnection	$0	$0	$0	$0	$0
Reconnect at Meter					
Regular Hours	$159	$164	$168	$171	$176
After Regular Hours	$60	$62	$64	$65	$67
Reconnect at Pole					
Regular Hours	$4	$4	$4	$5	$5
After Regular Hours	$1	$1	$1	$1	$1
Other					
Temporary Service - Install and Remove					
Overhead - no transformer	$12	$12	$12	$12	$13
Underground - no transformer	$26	$26	$27	$28	$28
Overhead - with transformer	$9	$10	$10	$10	$10
Specific Access to Power Poles					
Wireline Pole Attachments	$3,240	$3,373	$3,512	$3,657	$3,808
Wireless Pole Attachments	$69	$142	$217	$295	$376
Drycore Transformer Distribution Charge	$49	$53	$56	$59	$63
Energy Resource Facilities Charge	$0	$0	$0	$0	$0
TOTAL[6]	**$5,118**	**$5,394**	**$5,679**	**$5,910**	**$6,213**

[6] Totals may not sum due to rounding.

2.3.1. Arrears Certificate

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

Variance analysis:

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

2.3.2. Easement Certificate for Unregistered Easements

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

Variance analysis:

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

2.3.3. Duplicate Invoices for Previous Billing

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

Variance analysis:

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

2.3.4. Special Billing Service

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

Variance analysis:

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

2.3.5. Credit Reference/Credit Check

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

Variance analysis:

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

[7] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

2.3.6. Unprocessed Payment Charge

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

Variance analysis:

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

2.3.7. Account Set Up Charge/Change of Occupancy Charge

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

Variance analysis:

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

2.3.8. Interval Meter - Field Reading

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

Variance analysis:

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

2.3.9. High Bill Investigation - If Billing is Correct

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

Variance analysis:

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

2.3.10. Collection of Account Charge

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

Variance analysis:

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

2.3.11. Reconnect at Meter during Regular Hours

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

Variance analysis:

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

2.3.12. Reconnect at Meter after Regular Hours

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

Variance analysis:

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

2.3.13. Reconnect at Pole during Regular Hours

Hydro Ottawa is proposing to increase the current 2020 rate of $185 to $250 in 2021 and apply its 2.51% escalation factor each year for the 2022-2025 period. An increase in this charge is sought to recover associated labour and fleet costs. Reconnection at the pole is more costly, because two specially-qualified employees are required due to the increased safety requirements of pole work. While the volume was estimated at zero for the previous rate application, based upon more recent trending a volume of 17 per year is estimated for the 2021-2025 rate term.

Variance analysis:

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

2.3.14. Reconnect at Pole after Regular Hours

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

Variance analysis:

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

2.3.15. Temporary Service - Install & Remove

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

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

Variance analysis:

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

2.3.16. Specific Access to Power Poles - Wireline Attachments

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

Variance analysis:

Revenues in 2021 are forecasted to drop approximately $175K over the 2020 forecast.
Between 2022 and 2025, revenues are expected to increase modestly.

2.3.17. Specific Access to Power Poles - Wireless Attachments

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

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

Variance analysis:

Revenues between 2020 and 2025 are expected to increase modestly.

2.3.18. Dry Core Transformer Charges

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

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

Variance analysis:

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

2.3.19. Miscellaneous Revenue

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

3. LATE PAYMENT CHARGES

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

A decline in Late Payment Charge revenue is forecasted, taking into account the continued promotion of automated payment withdrawal services, effective use of the Auto Dialer tool during the Disconnection Moratorium timeframe, and additional proposed OEB Customer Service Rule changes.[8] Late Payment Charge revenue is expected to decline to $1.0M for the years 2020-2025.

4. OTHER OPERATING REVENUES

Other Operating Revenues include revenue associated from the provision of Standard Supply, Retailer, and Generator services. Tables 4 and 5 show Historical Year (2016-2018), Bridge Year (2019-2020), and Test Year (2021-2025) revenue for Other Operating Revenues.

Table 4 – 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
TOTAL[9]	**$1,368**	**$1,412**	**$1,438**	**$1,492**	**$1,527**

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
TOTAL[10]	**$2,790**	**$2,885**	**$2,971**	**$3,060**	**$3,163**

[8] Ontario Energy Board, Letter re: *Review of Customer Service Rules for Electricity and Gas (Phase 2)*, EB-2017-0183 (October 25, 2018).
[9] Totals may not sum due to rounding.
[10] Totals may not sum due to rounding.

4.1. STANDARD SUPPLY SERVICE ADMINISTRATION CHARGE

The Standard Supply Service Administration Charge ("SSS Charge") is an administrative charge that allows Hydro Ottawa to recover its costs of providing standard supply service to all customers who are not enrolled with a Retailer. The SSS Charge was introduced on May 11, 2005 as part of the 2006 EDR.[11]

The monthly SSS Charge of $0.25 per customer per month has not been adjusted to reflect actual costs or inflation since implementation. In light of the OEB's review of miscellaneous service charges, as announced on November 5, 2015, it is anticipated that this rate will be updated.[12] Until such time, Hydro Ottawa is proposing to increase the SSS Charge to align with the 2021-2025 Retailer Services, Distributor-Consolidated Billing monthly charge. The corresponding increase will result in customers paying an equal service charge regardless of electricity service provider, and the pricing between Hydro Ottawa and the Retailer will be relatively maintained.

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

Variance analysis:

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

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[11] Ontario Energy Board, *2006 Electricity Distribution Rate Handbook* (May 11, 2005), page 126.
[12] Ontario Energy Board, Letter re: *Review of Miscellaneous Rates and Charges*, EB-2015-0304 (November 5, 2015).

4.2. RETAILER SERVICES

Retailer Service Charges ("RSCs") recover the costs of services that Hydro Ottawa provides to electricity retailers, or their customers, in relation to the competitive supply of energy. The revenue generated from the RSCs have declined annually due to a reduction in the number of customers enrolled with a Retailer. Notwithstanding the decrease in retailer-enrolled customers, Hydro Ottawa's expenses related to these services have remained constant.

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

Variance analysis:

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

4.3. GENERATOR SERVICES

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

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

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

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

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

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

5. OTHER INCOME AND DEDUCTIONS

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

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

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

Tables 6 and 7 summarize Other Income and Deductions for the 2016-2025 period.

Table 6 – 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	$1,021	$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
TOTAL[13]	**$3,796**	**$5,230**	**$4,923**	**$1,270**	**$2,186**

Table 7 – 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
TOTAL[14]	**$2,069**	**$1,733**	**$2,017**	**$2,181**	**$2,081**

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,

[13] Totals may not sum due to rounding.
[14] Totals may not sum due to rounding.

generator services, and a recently introduced bill reporting service. A small amount of revenue is also forecasted for providing ad hoc web portal services for viewing interval meter data in a web-based format. Services to the City of Ottawa and to affiliates for the aforementioned services are included in USofA 4325 Revenues from Merchandise and 4330 Costs and Expenses of Merchandising.

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

5.2. PROPERTY RENTAL INCOME

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

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

5.3. GAINS AND LOSSES ON DISPOSAL OF UTILITY PROPERTY

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

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

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

5.4. SERVICES TO HYDRO OTTAWA AFFILIATES

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

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

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

Consistent with section 2.4.3.2 of the *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications*, as updated on July 12, 2018 and addended on July 15, 2019, as well as with

OEB guidance issued in 2018, SLA costs are no longer included in OM&A.[15] For additional details, please see Exhibit 4-2-1: Shared Services and Corporate Cost Allocation and Exhibit 4-1-4: Operations, Maintenance and Administration Cost Drivers and Program Variance Analysis for additional details.

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

Table 8 – Summary of Total Affiliate Services Revenue 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	Envari	$0	$0	$0	$1,688,131	$1,562,625	$1,601,691
TOTAL		**$2,219,312**	**$3,835,257**	**$4,090,179**	**$5,174,807**	**$4,682,905**	**$4,799,978**

5.5. INTEREST AND DIVIDEND INCOME

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

In the years 2016-2018, a modest amount of interest was recorded under USofA Account 4405. Material cash balances are not anticipated between 2019 and 2025.

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

5.6. VARIANCE ANALYSIS

5.6.1. 2016 Actual to 2017 Actual

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

5.6.2. 2017 Actual to 2018 Actual

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

5.6.3. 2018 Actual to 2019 Bridge Year

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

5.6.4. 2019 Bridge Year to 2020 Bridge Year

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

5.6.5. 2020 Bridge Year to 2021 Test Year

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

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2016 Actual²	2017 Actual²	2018 Actual²	2019 Actual	Bridge Year	Test Year	CGAAP
		2016	2017	2018	2019	2020	2021	Enter Transition Year
	Reporting Basis							CGAAP
4235	**Specific Service Charges**	$ 6,160,176	$ 5,490,013	$ 5,691,198	$ 5,534,597	$ 5,555,141	$ 5,118,168	
4225	**Late Payment Charges**	$ 1,029,257	$ 1,071,781	$ 1,041,348	$ 1,125,749	$ 1,000,000	$ 1,000,000	
4082	**Retail Services Revenues**	$ 153,634	$ 132,517	$ 119,505	$ 152,329	$ 181,688	$ 160,963	
4084	Service Transaction Requests	$ 6,011	$ 2,846	$ 2,539	$ 4,575	$ 6,191	$ 4,152	
4086	SSS Admin Charge	$ 951,238	$ 960,079	$ 973,147	$ 957,522	$ 935,917	$ 2,346,131	
4090	Electric Services Incidental to Energy Sales	$ 257,117	$ 316,106	$ 342,351	$ 377,619	$ 403,212	$ 278,736	
4315	Revenue from Leased Plant	$ 1,611,576	$ 1,648,672	$ 1,579,127	$ 1,584,923	$ 1,975,128	$ 1,975,128	
4325	Revenue from Merch, Jobbing	$ 5,917,316	$ 7,369,643	$ 10,296,349	$ 10,850,080	$ 9,119,993	$ 9,362,120	
4330	Expenses from Merch, Jobbing	-$ 3,911,728	-$ 4,062,736	-$ 7,267,853	-$ 10,680,465	-$ 8,608,009	-$ 8,879,355	
4355	Gain on Disposal of Property	$ -	$ -	$ -	$ -	$ -	$ -	
4360	Loss on Disposal of Property	$ -	$ -	$ -	$ -	$ -	$ -	
4362	Loss from Retirement of Utility and Other Property	$ 140,117	$ 198,349	$ 198,349	-$ 485,945	-$ 301,440	-$ 388,726	
4405	Interest and Dividend Income	$ 38,905	$ 75,768	$ 116,864	$ 933	$ -	$ -	
Specific Service Charges		$ 6,160,176	$ 5,490,013	$ 5,691,198	$ 5,534,597	$ 5,555,141	$ 5,118,168	
Late Payment Charges		$ 1,029,257	$ 1,071,781	$ 1,041,348	$ 1,125,749	$ 1,000,000	$ 1,000,000	
Other Operating Revenues		$ 1,367,999	$ 1,411,547	$ 1,437,542	$ 1,492,046	$ 1,527,008	$ 2,789,981	
Other Income or Deductions		$ 3,796,186	$ 5,229,696	$ 4,922,836	$ 1,269,526	$ 2,185,671	$ 2,069,167	
Total		$ 12,353,618	$ 13,203,037	$ 13,092,924	$ 9,421,918	$ 10,267,820	$ 10,977,316	$ -

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

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

Account Breakdown Details

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

Example: Account 4405 - Interest and Dividend Income

	2016 Actual²	2017 Actual²	2018 Actual²	2019 Actual	Bridge Year	Test Year	CGAAP
	2016	2017	2018	2019	2020	2021	Enter Transition Year
Reporting Basis							CGAAP
Short-term Investment Interest							
Bank Deposit Interest	$ 38,905	$ 75,768	$ 116,864	$ 933	$ -	$ -	
Miscellaneous Interest Revenue							
etc.1							
Total	$ 38,905	$ 75,768	$ 116,864	$ 933	$ -	$ -	$ -

Notes:

1 List and specify any other interest revenue.

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

Enter the number of "Other Operating Revenue" and "Other Income or Deductions" Accounts that require a detailed breakdown of the account components.

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".

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
Total Charged HOL to HOHI				**$861,944**	**$751,298**
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, Safey, 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
Total Charged HOL to EO				**$1,200,721**	**$1,100,957**
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
Total Charged HOL to CDM				**$503,511**	**$483,948**

* 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
Total Charged from HOHI to HOL					**$3,755,760**
HOHI	CDM	Management Services	Cost	14%	$175,060
Total Charged from HOHI to CDM					**$175,060**

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: 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
Total Charged HOL to HOHI				**$686,995**	**$630,732**
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, Safey, 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
Total Charged HOL to EO				**$2,618,406**	**$2,502,346**
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
Total Charged HOL to CDM				**$618,278**	**$590,950**

* 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
Total Charged from HOHI to HOL					**$3,793,215**
HOHI	CDM	Management Services	Cost	10%	$106,785
Total Charged from HOHI to CDM					**$106,785**

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: 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
Total Charged HOL to HOHI				**$1,081,984**	**$1,022,466**
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, Safey, 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
Total Charged HOL to EO				**$2,714,744**	**$2,582,994**
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
Total Charged HOL to CDM				**$652,942**	**$623,183**

* 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
Total Charged from HOHI to HOL					**$3,222,336**
HOHI	CDM	Management Services	Cost	11%	$92,207
Total Charged from HOHI to CDM					**$92,207**

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: 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	$268,851	$268,851
HOL	HOHI	Facilities	Market/Cost	$168,645	$87,629
HOL	HOHI	Finance	Cost	$116,153	$116,153
HOL	HOHI	Human Resources	Cost	$199,209	$199,209
HOL	HOHI	Information Technology	Cost	$426,866	$426,866
HOL	HOHI	Legal	Cost	$9,984	$9,984
HOL	HOHI	Regulatory	Cost	$91,638	$91,638
Total Charged HOL to HOHI				**$1,330,390**	**$1,249,374**
HOL	EO	Electricity Distribution Management	Cost	$24,519	$24,519
HOL	EO	Communications	Cost	$215,125	$215,125
HOL	EO	Facilities	Market/Cost	$20,736	$11,781
HOL	EO	Finance	Cost	$416,472	$416,472
HOL	EO	Human Resources, Safey, Environment and Business Continuity Management	Cost	$214,333	$214,333
HOL	EO	Information Technology	Cost	$505,500	$505,500
HOL	EO	Legal	Cost	$24,960	$24,960
HOL	EO	Regulatory Affairs	Cost	$45,816	$45,816
HOL	EO	Meter Data Services	Market	$18,600	*
HOL	EO	Mechanic Services	Cost	$166,339	$166,339
Total Charged HOL to EO				**$1,652,400**	**$1,624,845**
HOL	CDM	Human Resources	Cost	$85,186	$85,186
HOL	CDM	Facilities	Market/Cost	$38,517	$15,635
HOL	CDM	Information Technology	Cost	$182,538	$182,538
HOL	CDM	Finance	Cost	$60,000	$60,000
HOL	CDM	Communications	Cost	$68,076	$68,076
HOL	CDM	Fleet	Cost	$6,936	$6,936
Total Charged HOL to CDM				**$441,253**	**$418,371**
HOL	Envari	Electricity Distribution Management	Cost	$24,519	$24,519
HOL	Envari	Communications	Cost	$215,125	$215,125
HOL	Envari	Facilities	Market/Cost	$89,090	$53,507
HOL	Envari	Finance	Cost	$266,942	$266,942
HOL	Envari	Fleet	Cost	$11,734	$11,734
HOL	Envari	Human Resources	Cost	$209,690	$209,690
HOL	Envari	Information Technology	Cost	$449,331	$449,331
HOL	Envari	Key Accounts	Cost	$60,370	$60,370
HOL	Envari	Legal	Cost	$24,960	$24,960
HOL	Envari	Regulatory	Cost	$45,816	$45,816
HOL	Envari	Data Services	Cost	$58,950	$58,950
Total Charged HOL to Envari				**$1,456,527**	**$1,420,944**

* 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%	$806,789
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgt	Cost	56%	$1,223,927
HOHI	HOL	Human Resources	Cost	80%	$552,606
HOHI	HOL	Treasury	Cost	73%	$102,694
HOHI	HOL	Corporate Communications	Cost	48%	$635,455
HOHI	HOL	Legal, Corporate Admin	Cost	21%	$175,909
HOHI	HOL	Information Management & Technology	Cost	45%	$312,686
Total Charged from HOHI to HOL					**$3,810,066**
HOHI	CDM	Management Services	Cost	9%	$118,291
Total Charged from HOHI to CDM					**$118,291**

Note:

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· ***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.

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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
Total Charged HOL to HOHI				**$1,450,389**	**$1,353,738**
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, Safey, 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
Total Charged HOL to EO				**$1,669,891**	**$1,639,600**
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
Total Charged HOL to CDM				**$189,242**	**$180,570**
HOL	Envari	Electricity Distribution Management	Cost	$26,665	$26,665
HOL	Envari	Communications	Cost	$187,177	$187,177
HOL	Envari	Facilities	Market/Cost	$122,734	$74,648
HOL	Envari	Finance	Cost	$180,290	$180,290
HOL	Envari	Fleet	Cost	$11,731	$11,731
HOL	Envari	Human Resources	Cost	$217,439	$217,439
HOL	Envari	Information Technology	Cost	$571,566	$571,566
HOL	Envari	Key Accounts	Cost	$60,747	$60,747
HOL	Envari	Legal	Cost	$22,754	$22,754
HOL	Envari	Regulatory	Cost	$102,964	$102,964
HOL	Envari	Data Services	Cost	$58,560	$58,560
Total Charged HOL to Envari				**$1,562,627**	**$1,514,541**

* 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
Total Charged from HOHI to HOL					**$3,722,716**
HOHI	CDM	Management Services	Cost	3%	$45,898
Total Charged from HOHI to CDM					**$45,898**

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

Year: 2021

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	$54,663	$54,663
HOL	HOHI	Communications	Cost	$242,701	$242,701
HOL	HOHI	Facilities	Market/Cost	$220,837	$121,770
HOL	HOHI	Finance	Cost	$18,214	$18,214
HOL	HOHI	Human Resources	Cost	$201,131	$201,131
HOL	HOHI	Information Technology	Cost	$528,698	$528,698
HOL	HOHI	Legal	Cost	$9,329	$9,329
HOL	HOHI	Regulatory	Cost	$211,076	$211,076
Total Charged HOL to HOHI				**$1,486,649**	**$1,387,582**
HOL	EO	Communications	Cost	$191,856	$191,856
HOL	EO	Facilities	Market/Cost	$28,001	$16,018
HOL	EO	Finance	Cost	$478,581	$478,581
HOL	EO	Human Resources, Safey, Environment and Business Continuity Management	Cost	$222,499	$222,499
HOL	EO	Information Technology	Cost	$485,831	$485,831
HOL	EO	Legal	Cost	$23,322	$23,322
HOL	EO	Regulatory Affairs	Cost	$105,538	$105,538
HOL	EO	Meter Data Services	Market	$19,065	*
HOL	EO	Mechanic Services	Cost	$156,945	$156,945
Total Charged HOL to EO				**$1,711,638**	**$1,680,590**
HOL	CDM	Human Resources	Cost	$6,553	$6,553
HOL	CDM	Facilities	Market/Cost	$2,740	$1,397
HOL	CDM	Information Technology	Cost	$14,042	$14,042
HOL	CDM	Finance	Cost	$8,250	$8,250
HOL	CDM	Communications	Cost	$3,154	$3,154
Total Charged HOL to CDM				**$34,739**	**$33,396**
HOL	Envari	Electricity Distribution Management	Cost	$27,332	$27,332
HOL	Envari	Communications	Cost	$191,856	$191,856
HOL	Envari	Facilities	Market/Cost	$125,803	$76,515
HOL	Envari	Finance	Cost	$184,797	$184,797
HOL	Envari	Fleet	Cost	$12,024	$12,024
HOL	Envari	Human Resources	Cost	$222,875	$222,875
HOL	Envari	Information Technology	Cost	$585,855	$585,855
HOL	Envari	Key Accounts	Cost	$62,265	$62,265
HOL	Envari	Legal	Cost	$23,322	$23,322
HOL	Envari	Regulatory	Cost	$105,538	$105,538
HOL	Envari	Data Services	Cost	$60,024	$60,024
Total Charged HOL to Envari				**$1,601,691**	**$1,552,403**

* 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%	$702,093
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgt	Cost	57%	$1,177,035
HOHI	HOL	Human Resources	Cost	80%	$564,054
HOHI	HOL	Treasury	Cost	66%	$93,997
HOHI	HOL	Corporate Communications	Cost	57%	$765,135
HOHI	HOL	Legal, Corporate Admin	Cost	20%	$184,261
HOHI	HOL	Information Management & Technology	Cost	45%	$329,208
Total Charged from HOHI to HOL					**$3,815,783**
HOHI	CDM	Management Services	Cost	1%	$11,475
Total Charged from HOHI to CDM					**$11,475**

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