MILTON HYDRO DISTRIBUTION INC.

EXHIBIT 4

OPERATING EXPENSES

EXHIBIT 4 – OPERATING EXPENSES

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Attachment 4-4	2020 RSM ACTUARIAL REPORT
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Attachment 4-6	CORPORATE PURCHASING POLICY
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Attachment 4-11	INDECO STRATEGIC CONSULTING INC 2023 LRAMVA CLAIM REPORT & LRAMVA MODEL

4.1. OVERVIEW

Operating Expenses consist of Operations, Maintenance and Administration ("OM&A") costs and Depreciation and Taxes ("PILS"). These expenditures, from OEB Approved to the 2023 Test Year are summarized in Table 4-1 below.

Table 4-1 Summary of Operating Expenses

Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
OM&A	$9,572,448	$9,653,596	$8,941,246	$9,488,240	$10,081,958	$10,576,706	$12,109,938	$12,854,668	$15,133,537
Depreciation	$3,150,579	$3,272,885	$3,453,474	$3,733,407	$4,072,100	$4,286,293	$4,405,444	$4,783,340	$4,916,957
Taxes & PILS	$254,201	($196,556)	($729,191)	($414,892)	$1,923,679	$314,915	($630,941)	$22,311	$684,115
Total Operating Expenses	**$12,977,228**	**$12,729,925**	**$11,665,529**	**$12,806,755**	**$16,077,737**	**$15,177,914**	**$15,884,441**	**$17,660,319**	**$20,734,609**

Total Operating Expenses in the 2023 Test Year are $20,734,610. Milton Hydro's 2023 Test Year OM&A is $15,133,537. OM&A costs reflect the resourcing mix and investments required to meet customer and broader public policy requirements. Key OM&A cost drivers are explained in Exhibit 4.2 and required work program expenditures are explained in Exhibits 4.3. In these exhibits, information is provided on key initiatives, trends and material year over year variances. Details on staffing and compensation costs in support of OM&A and capital work programs are provided in Exhibit 4.4. Details on shared services and services provided to affiliates are provided in Exhibit 4.5.

Test Year Depreciation expense of $4,916,957 relates to historical and proposed capital expenditures and is discussed along with supporting detail in Exhibit 4.6.

Test Year Income Taxes (PILS) of $684,115 are discussed and supporting detail is provided in Exhibit 4.7., and Conservation and Demand Side Management programs, and the LRAMVA Variance Account are discussed in Exhibit 4.8.

4.1.1. Inflation Rate Assumed

For 2022 and 2023, Milton Hydro has assumed an inflation rate of 2.0% on Non-Labour items. Labour cost escalation for non-union and union employees, of 2.1% was used in the preparation of the operating and capital budgets. These assumptions are aligned to the collective agreement ratified for the period January 1, 2021, to December 31, 2023. The 2% is also consistent with an average of the range of rates set out in the Quarterly Economic Forecast, in September 2021 as shown in Table 4-2 below.

Table 4-2 2021- 2023 CPI Forecasts by Major Financial Institutions

CPI	2021E	2022F	2023F	Report Date
BMO	3.1%	3.0%		24-Sep-21
TD	3.1%	2.9%	2.2%	Sept-21
Scotia	3.1%	2.7%	2.6%	9-Sep-21
RBC	3.0%	2.4%		Sept-21
CIBC	2.9%	2.2%	2.1%	8-Sep-21
Average	**3.0%**	**2.6%**	**2.3%**	

4.1.1.1. Current Inflation Rates

Milton Hydro notes that the inflation rates used in this application are lower than the 3.3% inflation factor approved by the OEB on November 18, 2021 for use in 2022 IRM applications. Furthermore, Canada's annual inflation rate in February 2022 was 5.7%, the highest level seen since 1991[1]. The full impact and duration of this emerging trend is not yet known, however it is expected that Milton Hydro's operating and capital expenditure costs will be higher than what is currently in proposed 2023 rates. For example, there has been a 32% increase in the price of gasoline costs and this impacts Milton Hydro's fleet costs[2]. As a result of the recent volatility in inflation, and as this is an evolving situation, Milton Hydro notes the issue and will provide further assessment during the proceeding as the situation evolves.

4.1.2. OM&A Budgeting Process

In managing its distribution system assets and operations, Milton Hydro's main objective is to optimize performance of the assets at a reasonable cost with due regard for system reliability, safety, and customer service expectations. Milton Hydro is committed to providing its customers with an economical, safe, reliable supply of electricity and helping the Town of Milton become an energy efficient community.

The budgeting process at Milton Hydro is an integral planning tool and ensures that appropriate resources are available to support current period operations and to maintain and invest in required capital infrastructure. It is the responsibility of each department to contribute to the

[1] https://www150.statcan.gc.ca/n1/daily-quotidien/220316/dq220316a-eng.htm
[2] Monthly average retail prices for gasoline and fuel oil, by geography $1.59/lt/ $1.201 = 32% increase.

preparation of the Operating and Capital budget with the assistance of the Finance Department. The responsibility of the Finance Department is to coordinate the capital budget and forecast process and present a preliminary Operating budget to the President & CEO for approval. Once the preliminary Operating budget has been approved by the President & CEO there is a Budget meeting with the Board of Directors where the budget is presented for review. Any amendments are made to the budget are then made and an updated budget is presented to the Board at its next meeting for approval

Once the Board of Directors approves the annual budget the budget amounts do not change and they provide the reference plan against which actual results are compared and explained.

The operating budget is an integral component of the overall budget process and is further described in Exhibit 1, Section 1.6.2.

Milton Hydro's Distribution System Plan ("DSP") and Asset Management Plan, also are used to determine the necessary distribution system operations and maintenance expenditures need to help ensure safe, reliable delivery of electricity to customers. This information is provided in Exhibit 2, Attachment 2-2 and Appendix D of Attachment 2-2.

4.1.3. Summary of Recoverable OM&A Expenses

Milton Hydro's OM&A plan is developed to ensure that it continues to provide reliable, efficient and safe energy solutions to the community by achieving its core strategic objectives. The plan was informed by a number of factors, including operational needs (e.g., requirements relating to capital investment; operations and maintenance; and staffing), legislative and regulatory obligations and ongoing engagement with customers.

Milton Hydro follows the OEB's Accounting Procedures Handbook (the "APH") in categorizing work performed between operations and maintenance. A summary of Milton Hydro's OM&A expenses for the 2016 OEB Approved, 2016-2021 Actual, 2022 Bridge Year and the 2023 Test Year, is provided in Table 4-3 which is OEB Chapter 2 Appendix 2-JA.

Milton Hydro notes, with respect to Appendix 2-JA, when it reviewed the prepopulated historical actual costs in the OEB Chapter 2 Appendices model that was made available to the 2022 Cost of Service filers, Milton Hydro identified a difference between the total aggregate OM&A costs filed in its annual 2.1.7 RRR Trial Balance each year as compared to the prepopulated aggregate OM&A in the model and made two adjustments pertaining to Appendix 2-JA. The first adjustment relates to ensuring the aggregate balances agree with the data it filed in its annual RRR 2.1.7 Trial Balances for 2016 to 2020. The second adjustment was to reflect retrospective reallocation between specific General Ledger account for 2016 to 2021 line items to make them consistent with the allocations being used for the 2022 Bridge Year and 2023 Test Year.

Adjustments & Reclassification of Appendix 2-JA OM&A Costs

Prepopulated In OEB Chapter 2 Appendices File

Cost Description	2016 Last Rebasing Year OEB Approved	2016 Year Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals
Operations	$1,993,286	$2,436,465	$2,239,574	$2,371,190	$2,460,780	$2,548,732
Maintenance	$1,583,125	$1,360,880	$1,095,331	$1,401,782	$1,512,621	$1,332,079
Billing and Collecting	$1,924,409	$2,037,515	$2,224,512	$2,099,123	$2,120,870	$2,218,766
Community Relations	$20,071	$8,680	$14,094	$10,120	$9,650	$17,500
Administrative and General	$4,051,557	$3,794,956	$3,352,635	$3,593,592	$3,965,604	$4,447,196
Total	$9,572,448	$9,638,496	$8,926,146	$9,475,807	$10,069,525	$10,564,273
% Change (year over year)		0.70%	(7.40%)	6.20%	6.30%	4.90%

Totals As filed with OEB RRR 2.1.7 Trial Balances & Reallocated by Milton Hydro

Cost Description	2016 Last Rebasing Year OEB Approved	2016 Last Rebasing Year Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals
Operations	$1,993,286	$2,048,998	$1,897,672	$1,968,811	$2,083,159	$2,152,220
Maintenance	$1,583,125	$1,748,350	$1,437,233	$1,804,161	$1,890,242	$1,728,590
Billing and Collecting	$1,924,409	$1,823,188	$1,928,847	$1,786,132	$1,783,154	$1,877,132
Community Relations	$20,071	$8,680	$14,094	$10,120	$9,650	$17,500
Administrative and General	$4,051,557	$4,024,379	$3,663,400	$3,919,016	$4,315,753	$4,801,264
Total	$9,572,448	$9,653,596	$8,941,246	$9,488,240	$10,081,958	$10,576,706
% Change (year over year)		0.80%	(7.40%)	6.10%	6.30%	4.90%

Adjustments

Cost Description	2016 Last Rebasing Year OEB Approved	2016 Last Rebasing Year Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals
Operations	$—	$387,467	$341,902	$402,379	$377,621	$396,512
Maintenance	$—	-$ 387,470	-$ 341,902	-$ 402,379	-$ 377,621	-$ 396,511
Billing and Collecting	$—	$214,327	$295,665	$312,991	$337,716	$341,634
Community Relations	$—	$—	$—	$—	$—	-$ 0
Administrative and General	$—	-$ 229,423	-$ 310,765	-$ 325,424	-$ 350,149	-$ 354,068
Total	$—	-$ 15,100	-$ 15,100	-$ 12,433	-$ 12,433	-$ 12,433
% Change (year over year)		0.80%	(7.40%)	6.10%	6.30%	4.90%

Table 4-3 OM&A Summary (Appendix 2-JA)

	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
Operations	$1,993,286	$2,048,998	$1,897,672	$1,968,811	$2,083,159	$2,152,220	$2,787,520	$2,603,643	$3,803,779
Maintenance	$1,583,125	$1,748,350	$1,437,233	$1,804,161	$1,890,242	$1,728,590	$1,960,504	$1,688,242	$1,568,935
SubTotal	**$3,576,411**	**$3,797,348**	**$3,334,905**	**$3,772,972**	**$3,973,401**	**$3,880,810**	**$4,748,024**	**$4,291,885**	**$5,372,714**
%Change (year over year)		**6.2%**	**(12.2%**	**13.1%**	**5.3%**	**(2.3%**	**22.3%**	**(9.6%**	**25.2%**
%Change (Test Year vs Last Rebasing Year - Actual)									**41.5%**
Billing and Collecting	$1,924,409	$1,823,188	$1,928,847	$1,786,132	$1,783,154	$1,877,132	$1,852,684	$2,092,792	$2,191,670
Community Relations	$20,071	$8,680	$14,094	$10,120	$9,650	$17,500	$8,094	$94,100	$115,837
Administrative and General	$4,051,557	$4,024,379	$3,663,400	$3,919,016	$4,315,753	$4,801,264	$5,501,136	$6,375,891	$7,453,317
SubTotal	**$5,996,037**	**$5,856,248**	**$5,606,341**	**$5,715,268**	**$6,108,557**	**$6,695,896**	**$7,361,914**	**$8,562,783**	**$9,760,824**
%Change (year over year)		**(2.3%**	**(4.3%**	**1.9%**	**6.9%**	**9.6%**	**9.9%**	**16.3%**	**14.0%**
%Change (Test Year vs Last Rebasing Year - Actual)									**66.7%**
Total	**$9,572,448**	**$9,653,596**	**$8,941,246**	**$9,488,240**	**$10,081,958**	**$10,576,706**	**$12,109,938**	**$12,854,668**	**$15,133,537**
%Change (year over year)		**0.8%**	**(7.4%**	**6.1%**	**6.3%**	**4.9%**	**14.5%**	**6.1%**	**17.7%**

	2016 OEB Approved	2016 Actual	2016 Actual vs. 2016 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2022 Bridge Year vs. 2021 Actual	2023 Test Year	2023 Test Year vs. 2022 Bridge Year
Operations	$1,993,286	$2,048,998	($55,712)	$1,897,672	$1,968,811	$2,083,159	$2,152,220	$2,787,520	$2,603,643	($183,877)	$3,803,779	$1,200,136
Maintenance	$1,583,125	$1,748,350	($165,225)	$1,437,233	$1,804,161	$1,890,242	$1,728,590	$1,960,504	$1,688,242	($272,262)	$1,568,935	($119,308)
Billing and Collecting	$1,924,409	$1,823,188	$101,221	$1,928,847	$1,786,132	$1,783,154	$1,877,132	$1,852,684	$2,092,792	$240,108	$2,191,670	$98,878
Community Relations	$20,071	$8,680	$11,391	$14,094	$10,120	$9,650	$17,500	$8,094	$94,100	$86,006	$115,837	$21,737
Administrative and General	$4,051,557	$4,024,379	$27,178	$3,663,400	$3,919,016	$4,315,753	$4,801,264	$5,501,136	$6,375,891	$874,755	$7,453,317	$1,077,427
Total OM&A Expenses			($81,148)	$8,941,246	$9,488,240	$10,081,958	$10,576,706	$12,109,938	$12,854,668	$744,730	$15,133,537	$2,278,869
Adjustments for Total non-recoverable items3												
Total Recoverable OM&A Expenses	$9,572,448	$9,653,596	($81,148)	$8,941,246	$9,488,240	$10,081,958	$10,576,706	$12,109,938	$12,854,668	$744,730	$15,133,537	$2,278,869
Variance from previous year				($712,349)	$546,994	$593,718	$494,748	$1,533,231	$744,730		$2,278,869	
Percent change (year over year)				(7.4%	6.1%	6.3%	4.9%	14.5%	6.1%		17.7%	
Percent Change: Test year vs. Most Current Actual											25.0%	
Simple average of % variance for all years											6.9%	
Compound Annual Growth Rate for all years												6.6%
Compound Growth Rate (2021 vs. 2016 Actuals)											4.6%	

2023 Test Year OM&A expenditures are 58% higher than 2016 OEB Approved expenditures. The primary reasons for this increase are higher levels of General Administration costs in support of work programs, inflation impacts on labour and non-labour costs, and increased costs in support of the expanding customer and asset base. Also included are the costs of new initiatives in support of Milton Hydro's 2.0 strategic direction, infrastructure development, staff resourcing, new systems, and Control Room operations being established "in-house" (as compared to the current practice of outsourcing this function). More detailed reasons for the overall increase from 2016 to 2023, and an explanation of material year-over-year increases in OM&A, are provided in Exhibits 4.2 and 4.3.

Some of these initiatives are planned to start in 2023 and as such 2023 Test Year OM&A is $2,278,870 (17.7%) higher than the 2022 Bridge Year. This increase is primarily due to higher General Administration and Executive related expenditures related to the hiring of new positions in support of Milton Hydro's strategic direction and increased Operations expenditures related to bringing the system Control room "in house".

4.1.4. OM&A Cost per Customer and Full-Time Equivalent

Included in Table 4-4, which is Board Appendix 2-L, is a summary of OM&A Cost per Customer and per Full-Time Equivalent (FTE). The FTEs agree to the numbers shown in Table 4-60 Appendix 2-K in Exhibit 4.4 Workforce Planning. The number of customers is based on the annual average for each rate class of metered customers.

In 2023, OM&A per customer is forecast to be $345. This is $80 (30.2%) higher than the $265 OM&A per customer ratio in 2016. Milton Hydro notes that inflation in OM&A costs since 2016 accounts for about half of this increase. The other half is related to additional programming and staffing costs that are discussed in Exhibits 4.3 and 4.4.

In 2023, OM&A Costs per FTE are forecast to be $194,769. This is $39,119 (25.1%) higher than the $155,650 amount in 2016. It is important to note that inflation over this period is estimated to be 17.3%.

Table 4-4 Appendix 2-L Recoverable OM&A Cost per Customer and per FTE

	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
OM&A Costs									
O&M	$3,576,411	$3,797,348	$3,334,905	$3,772,972	$3,973,401	$3,880,810	$4,748,024	$4,291,885	$5,372,714
Admin Expenses	$5,996,037	$5,856,248	$5,606,341	$5,715,268	$6,108,557	$6,695,896	$7,361,914	$8,562,783	$9,760,824
Total Recoverable OM&A from Appendix 2-JB	$9,572,448	$9,653,596	$8,941,246	$9,488,240	$10,081,958	$10,576,706	$12,109,938	$12,854,668	$15,133,537
Number of Customers	36,976	36,450	37,327	38,829	40,052	40,801	41,558	42,695	43,863
Number of FTEs	61.5	60.2	60.4	57.9	56.3	55.3	58.5	69.7	77.7
Customers/FTEs	601.24	605.48	617.99	670.62	711.41	737.81	710.39	612.55	564.52
OM&A cost per customer									
O&M per customer	$97	$104	$89	$97	$99	$95	$114	$101	$122
Admin per customer	$162	$161	$150	$147	$153	$164	$177	$201	$223
Total OM&A per customer	$259	$265	$240	$244	$252	$259	$291	$301	$345
OM&A cost per FTE									
O&M per FTE	$58,153	$63,079	$55,214	$65,164	$70,576	$70,177	$81,163	$61,577	$69,147
Admin per FTE	$97,497	$97,280	$92,820	$98,709	$108,500	$121,083	$125,845	$122,852	$125,622
Total OM&A per FTE	$155,650	$160,359	$148,034	$163,873	$179,076	$191,261	$207,007	$184,429	$194,769

4.2. SUMMARY AND COST DRIVERS

2023 Test Year OM&A costs of $15,133,537 are $5,561,090 higher than the 2016 OEB Approved level. Table 4-5, which is OEB Appendix 2-JB with a "Total" column added, provides a summary of the main cost drivers associated with OM&A changes from 2016 OEB Approved levels to the 2023 Test Year.

Table 4-5 Appendix 2-JB - Cost Driver Table

OM&A	2016 OEB Approved to 2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year	Total
Opening Balance	**$9,572,448**	**$9,653,596**	**$8,941,246**	**$9,488,240**	**$10,081,958**	**$10,576,707**	**$12,109,938**	**$12,854,668**	**$9,572,448**
Wages, Salaries, Progressions and Benefits	$235	($214,804)	$92,868	$78,236	$489,828	$707,591	$1,488,054	$805,410	**$3,447,418**
Incentive Plan & Director Remuneration	$63,216	($10,803)	$11,454	$80,587	($16,803)	$119,404	($415,708)	$1,645	**($167,007)**
Management Fee	($18,520)	$1,353	($2,399)	$91,790	($14,943)	($15,726)	$37,243	$1,861	**$80,658**
Customer Focus Drivers									
Bad Debts	($47,356)	$23,602	$30,324	$33,952	($35,447)	$62,769	($45,932)	$5,576	**$27,487**
Collections	($33,176)	($11,980)	($39,491)	$12,969	($29,557)	$2,732	$302	$58,823	**($39,379)**
Community Relations	($10,641)	$5,414	($3,974)	($470)	$7,850	($9,406)	$86,006	$21,737	**$96,516**
Conventions/Meetings	($8,263)	($12,122)	$7,534	($1,565)	$15,482	($64,583)	$43,977	$5,362	**($14,178)**
Customer Premise Maintenance	($11,779)	($4,823)	$62,873	$16,741	$15,809	($46,698)	($32,123)	$—	**$—**
Meter Reading	$9,002	($11,824)	$7,835	($6,488)	$6,187	$12,082	$7,259	$720	**$24,774**
Monthly Billing	($20,352)	$1,101	($41,745)	($9,713)	($4,783)	$8,994	$50,756	$4,954	**($10,788)**
Postage/ Mail Service/ Stationary	($29,522)	($4,170)	$3,453	($2,598)	$42,229	($98,671)	$44,246	$3,811	**($41,223)**
Service Locates	($21,800)	$16,319	($1,489)	$10,172	($44,261)	$40,510	$57,779	$6,558	**$63,788**
Telephone	$25,658	$6,313	$16,006	$8,284	($2,039)	$17,397	$12,771	($18,377)	**$66,014**
Training	$29,933	($127)	$41,379	$23,220	($24,040)	($71,928)	$50,151	$6,246	**$54,835**
Operational Effectiveness Drivers									
Audit/ Legal/ Insurance	$10,080	($54,872)	$50,693	$5,511	$44,901	($2,033)	($807)	$2,888	**$56,362**
Bank Charges	($4,457)	($429)	$1,470	$709	($432)	$6,461	$56,246	$1,350	**$60,917**
Building Maintenance/taxes	($25,174)	$12,834	$84,606	($10,702)	$16,642	$64,925	($4,663)	$38,430	**$176,899**
Computer Services/Software Maintenance	($149,404)	$119,472	$36,462	$32,292	$53,090	$94,275	$57,229	$102,359	**$345,775**
Consulting	$65,341	($13,220)	$37,871	$121,495	($31,230)	$383,638	($429,438)	$65,016	**$199,472**
Control Room	($43,954)	$60,904	($46,950)	$6,425	$39,625	$28,509	$33,941	$908,797	**$987,297**
Maintenance of Line Transformers	($13,768)	$20,722	$16,710	$42,166	($76,118)	$30,642	($21,924)	$576	**($994)**
Maintenance of OH & UG conductors	$26,531	($9,035)	$23,272	$78,352	($10,701)	($31,950)	($25,403)	$2,256	**$53,323**
Meter Maintenance	($22,013)	($33,961)	$31,068	($9,010)	($34,377)	$35,749	($39,542)	$764	**($71,322)**
Moving Expenses	$20,946	($20,946)	$—	$—	$—	$—	$—	$—	**$—**
Pole Maintenance	$246,961	($259,219)	$57,565	($38,288)	($22,090)	$3,204	$16,867	$1,350	**$6,350**
Stores / Inventory Adjustments	$115,160	($134,649)	$10,974	$39,967	($79,242)	$142,812	($85,903)	$2,433	**$11,553**
Transformer Station Maintenance	$5,913	$17,176	($15,083)	($6,441)	$49,089	$143,949	($158,063)	$676	**$37,217**
Tree Trimming	($198,492)	$3,625	$126,419	($54,007)	$141,193	($258,029)	$154,490	$5,250	**($79,550)**
Miscellaneous	$10,303	$35,616	($44,873)	$42,456	$5,112	$186,792	($161,297)	$4,041	**$78,152**
Public Policy Drivers									
Regulatory Costs	$110,540	($239,817)	($7,839)	$7,676	($6,227)	$39,818	($31,784)	$238,356	**$110,723**
Sub-Total OM&A	**$81,148**	**($712,349)**	**$546,994**	**$593,718**	**$494,748**	**$1,533,231**	**$744,730**	**$2,278,869**	**$5,561,090**
Closing Balance	**$9,653,596**	**$8,941,246**	**$9,488,240**	**$10,081,958**	**$10,576,707**	**$12,109,938**	**$12,854,668**	**$15,133,538**	**$15,133,538**

For each driver, costs increase and decrease on a year-over-year basis throughout the 2016 to 2023 period. In general, these changes relate to timing differences on the execution of work, changing priorities, new initiatives, and general escalation. The following discusses the material changes in the 2023 Test Year as compared to the 2016 OEB Approved levels by primary driver.

93% of the total OM&A increase from 2016 Approved to the 2023 Test Year is identified as in Table 4-6 as follows:

Table 4-6 Primary Cost Drivers

Primary Cost Drivers 2016 -2023	$
Wages, Salaries, Progressions and Benefits	$3,447,418
Computer Services / Software Maintenance	$345,775
Control Room	$987,297
Building Maintenance / Taxes:	$176,899
Consulting	$199,472
Incentive Plan and Director	$167,007
Total	**$5,323,868**

Wages, Salaries, Progressions and Benefits increase by $3,447,418 primarily due to hiring new positions in order to support growing customer base and distribution system as Milton Hydro transitions to a large-size LDC. In 2023, the plan is to have 77.7 FTE's as compared 61.6 FTE's that were in the 2016 rate application. In addition, there has been general wage escalation since 2016 as the result of negotiated wage increases with the union and inflationary based increases for non-union staff. The increase in FTEs was required to address the right-sizing of Milton Hydro's workforce which did not grow at the pace of the growth in the number of customers. For example, at the end of 2021 Milton Hydro served 710 customers per employee, which is 18% higher than the 601 customers per employee approved in 2016.

To help achieve Milton Hydro's 2.0 Strategy, the utility retained a third-party expert to review Milton Hydro’s current organization structure against its needs and recommend resources required to affirm the continued effective and efficient operations of the business. As a result of the resourcing issues identified in 2021, Milton Hydro began to address the identified resourcing shortfalls in part by adding FTEs.

Milton Hydro's resourcing issues are not only being addressed by adding FTE's. Milton Hydro also began making investments in digital modernization and process innovation starting in 2021.

Milton Hydro has included budget amounts related to staffing costs in Information Technology to defend against cyber security threats and to mitigate system disturbances related to cyber security breaches. The increase in Computer Services/Software Maintenance costs of $345,775 are a component of Milton Hydro's investment in digital modernization; the Company is also making capital expenditures in 2022 and 2023 for new software systems including a new ERP System in which is expected to be in service in 2024. In 2021, based on the outcomes of a third-party report that was commissioned, Milton Hydro began to invest in digital modernization to possess the computer systems it needs to achieve Milton Hydro's 2.0 Strategic Objectives. The ***IT Strategy & Roadmap*** lays out the IT Strategic Objectives that Milton Hydro's 2.0 Strategy needs to achieve.

In **the 4th quarter of** 2021, Milton Hydro hired a *Process Improvement Officer* (PIO), adding a new role and discipline to the organization. As a Lean Six Sigma black belt certified professional, the incumbent's focus is to deliver process innovation and continuous improvement initiatives across the organization.

Milton Hydro also made a business case for a new in-house system control room (Exhibit 4.4, Attachment 4-1) to improve system reliability, and enable better service to customers in the event of system power outages. OM&A costs increase by $987,297 as the result of creating a new in-house system control room; in addition, there are also capital investments related to the system control room. This investment will enable Milton Hydro to be ready for the future as a DSO and will manage and control its grid appropriately, with the advent of the electrification of transportation and the connection of DERs.

Building Maintenance/Taxes increased by $176,899, primarily due to increased taxes for the new head office building and increased expenses for outside maintenance contracts such as janitorial, snow and lawn maintenance.

Consulting costs increased by $199,473, primarily to due to safety consulting, cyber security and portal services, respect in the workplace education, privacy audit education, process and procedures and implementation of human resources practices and professional services.

It is also noted that the decrease of $167,007 in Incentive Plan & Director Remuneration, is due to budgeting for this item being included at the departmental level in starting in 2022 and going forward.

Milton Hydro is requesting 2023 Test Year OM&A of $15,133,537. This amount is after the transfer of certain "OM&A" costs charged to capital as part of the overhead capitalization rate. Table 4-7 summarizes the amount of "OM&A" costs that are part of overhead capitalization.

Table 4-7 Capitalized OM&A

Capitalized OM&A	2020 Historical Year	2021 Historical Year	2022 Bridge Year	2023 Test Year
Employee Labour and Benefits	$1,596,323	$1,253,050	$2,025,750	$2,073,366
Fleet /Truck Time	$277,926	$185,740	$349,273	$356,258
Total Capitalized OM&A	**$1,874,248**	**$1,438,790**	**$2,375,023**	**$2,429,625**

Capitalized OM&A in the 2023 Test Year is $555,377 higher than 2020 Actual. The level of 2023 Test Year Capitalized OM&A is due to an increase in headcount and truck time along with increase in-house capital initiatives.

2023 Test Year over 2021 Actual is $990,835 is higher due to: an increase focus on internal resources completing capital programs in 2023; higher fleet utilization on capital programs dues to the internal resourcing of capital work; increased productive time for employees in 2023 related to the workplans returning to pre-pandemic levels; and lower metering capital due to early retirements and supply chain issues to complete the 2021 metering program - deferred to 2022; and lower engineering administration time allocated to capital corresponding to the staff supporting the development of the cost of service application.

4.3. PROGRAM DELIVERY COSTS WITH VARIANCE ANALYSIS

4.3.1. Overview of Program Delivery

The costs discussed in this Exhibit represent expenditures that are required to maintain, operate and administer Milton Hydro's distribution system assets at the targeted levels of performance, to meet customer expectations, ensure public and employee safety, and provide quality service. These costs are necessary to comply with the Distribution System Code, environmental requirements, and government direction.

The Operations and Maintenance functions are a key component of delivering reliable service to customers. These work programs are responsible for minimizing reactive maintenance by following an effective and proactive planned maintenance program. Appropriate levels of maintenance help to:

a. reduce safety risks

b. increase network reliability

c. increase energy efficiency

d. minimize reactive (emergency) maintenance

e. reduce downtime

f. extend the useful service life of assets, and

g. decrease total cost of ownership

Preventative maintenance includes planned activities such as: tree trimming, network component repairs and replacements, load-break switches, transformer and switchgear maintenance, inspection of underground vaults and maintenance holes, and cable testing.

Predictive maintenance includes work such as: testing and performance analysis on distribution assets to assess their condition and to forecast potential for premature failure. These activities minimize unscheduled downtime, which helps to reduce overall cost and ensure a reliable, electricity distribution infrastructure.

The Operations and Maintenance Program follows a Geographic Information System (“GIS”) scheduled maintenance program that was developed by the Engineering department and is based on the Electrical Safety Authority and OEB Distribution System Code requirements. The GIS is utilized to monitor and control all inspection activities, including timelines and infrastructure inspected, and to ensure deficiencies resolved are recorded.

Maintenance activities are performed on an established cycle to reduce the number of unplanned outages by identifying and correcting deficiencies before a failure occurs. By reducing unplanned outages and maximizing equipment lifespan, Milton Hydro can provide more reliable service to its customers at the lowest cost. Milton Hydro uses a combination of defined inspection schedules and defined maintenance activities within its Asset Management Plan to complete inspection requirements and then updates database information regarding the condition of distribution assets. At a minimum, one third of each major asset category is either inspected or has maintenance performed each year. Where equipment is prone to more frequent failure, such as air-insulated switchgear, equipment is inspected on an annual basis. During inspections, minor maintenance and critical items that can be addressed immediately are resolved and reported. Major maintenance requiring more complex coordination is scheduled for completion within the year or planned for future years as identified in the Asset Management Plan

Milton Hydro uses metrics and performance measures to help it understand the effectiveness of its operation and maintenance programs such as:

a. studies of equipment failures to determine if current maintenance is sufficient, whether a new maintenance program is required or whether a capital project should be implemented to replace the equipment

b. inspection types and quantities are monitored monthly to ensure internal and external requirements are met

c. detailed outage analysis by Systems Planning including review of the annual number of failures by equipment type and the overall effect on SAIDI and SAIFI. This helps to determine whether a certain type, manufacturer or model of equipment needs to have a maintenance program created or altered or if a capital program is required to replace the equipment

OM&A work program costs for the 2016 to 2023 period are summarized in Table 4-8, which is OEB Appendix 2-JC. These work programs contribute to achieving the Renewed Regulatory Framework (RRF) performance outcomes of Customer Focus, Operational Effectiveness, and Public & Regulatory Responsiveness. 2023 OM&A expenditures of $15,133,537 are required to help ensure Milton Hydro can meet current and future, operational and customer needs. Each work program is subsequently described and expenditure levels along with material variance explanations are provided.

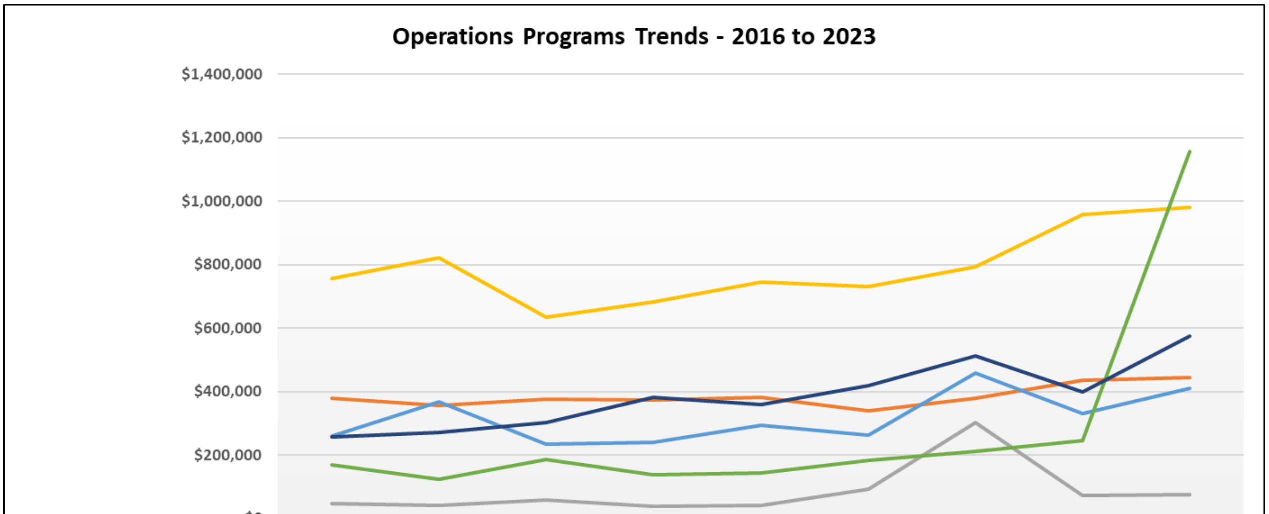
Table 4-8 Appendix 2-JC - OM&A Programs Table

Programs	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year	2023 Test Year vs. 2021 Actual	2023 Test Year vs. 2016 OEB Approved
Operations											
Underground Locates	$380,000	$358,200	$378,024	$373,373	$383,562	$338,981	$379,451	$437,230	$443,788	$64,338	$63,788
Transformer Station	$48,528	$42,097	$59,666	$37,960	$42,166	$93,846	$302,383	$74,681	$75,536	$(226,847)	$27,008
Engineering Administration	$758,285	$820,851	$634,983	$682,566	$744,927	$730,575	$792,439	$959,438	$979,899	$187,460	$221,613
Stores Administration	$260,418	$368,816	$235,779	$241,891	$295,126	$262,309	$458,839	$332,446	$409,692	$(49,147)	$149,274
Control Room Services	$168,600	$124,646	$185,550	$138,600	$145,025	$184,650	$213,159	$247,100	$1,155,897	$942,738	$987,297
Customer Premise	$258,653	$271,661	$302,193	$382,742	$359,653	$418,959	$513,419	$400,418	$576,600	$63,181	$317,947
Sub-Total	**$1,874,484**	**$1,986,272**	**$1,796,194**	**$1,857,132**	**$1,970,458**	**$2,029,321**	**$2,659,690**	**$2,451,314**	**$3,641,413**	**$981,723**	**$1,766,929**
Maintenance											
Meter Maintenance	$392,437	$437,655	$369,993	$412,303	$389,427	$396,814	$445,148	$399,934	$407,808	$(37,340)	$15,371
Overhead Lines	$266,754	$303,099	$297,263	$349,235	$440,735	$378,090	$591,491	$379,311	$314,936	$(276,555)	$48,182
Pole Maintenance	$177,726	$473,535	$161,499	$389,879	$333,646	$157,965	$273,722	$157,495	$142,644	$(131,078)	$(35,082)
Maintenance of Line Transformers	$225,972	$150,213	$176,479	$178,194	$278,315	$161,041	$209,203	$215,682	$183,345	$(25,858)	$(42,627)
Underground Lines	$39,714	$118,052	$148,734	$67,439	$103,220	$121,306	$170,264	$143,081	$129,133	$(41,130)	$89,419
Tree Trimming	$445,522	$245,358	$259,508	$373,691	$325,314	$473,379	$213,394	$381,227	$378,981	$165,587	$(66,541)
Sub-Total	$1,548,125	$1,727,913	$1,413,476	$1,770,741	$1,870,657	$1,688,594	$1,903,222	$1,676,731	$1,556,847	$(346,374)	$8,722
Customer Service											
Meter Reading	$131,100	$161,517	$150,027	$133,303	$110,791	$154,100	$120,183	$189,958	$193,319	$73,136	$62,219
Billing	$947,646	$897,098	$969,237	$897,603	$860,954	$953,020	$879,801	$1,034,713	$1,051,995	$172,194	$104,349
Customer Service	$791,063	$742,767	$763,916	$692,133	$700,513	$712,320	$749,739	$768,121	$841,356	$91,617	$50,293
Community Relations	$20,071	$8,680	$14,094	$10,120	$9,650	$17,500	$8,094	$94,100	$115,837	$107,743	$95,766
Bad Debt	$89,600	$42,244	$65,846	$96,170	$130,122	$94,675	$157,444	$111,512	$117,087	$(40,357)	$27,487
Sub-Total	**$1,979,480**	**$1,852,306**	**$1,963,121**	**$1,829,328**	**$1,812,029**	**$1,931,615**	**$1,915,261**	**$2,198,404**	**$2,319,594**	**$404,333**	**$340,114**
Administration											
General Administration	$2,143,949	$2,207,004	$2,093,305	$2,302,022	$2,582,337	$2,859,440	$3,533,049	$3,473,283	$3,958,082	$425,033	$1,814,133
Software Maintenance	$498,477	$324,397	$452,274	$491,752	$524,156	$575,582	$646,736	$729,966	$832,135	$185,400	$333,658
Regulatory	$444,060	$560,450	$326,658	$325,025	$339,094	$411,331	$469,548	$503,518	$750,664	$281,116	$306,604
Executive and Board Expenses	$1,083,873	$995,254	$896,219	$912,240	$983,228	$1,080,824	$982,433	$1,821,452	$2,074,802	$1,092,369	$990,929
Sub-Total	**$4,170,359**	**$4,087,105**	**$3,768,456**	**$4,031,039**	**$4,428,814**	**$4,927,177**	**$5,631,766**	**$6,528,220**	**$7,615,683**	**$1,983,918**	**$3,445,324**
Total	**$9,572,448**	**$9,653,596**	**$8,941,246**	**$9,488,240**	**$10,081,958**	**$10,576,706**	**$12,109,938**	**$12,854,668**	**$15,133,537**	**$3,023,599**	**$5,561,089**

4.3.2. Operations Work Programs

The Operations category is comprised of Underground Locates, Transformer Station, Engineering Administration, Stores Administration, Control Room Services and Customer Premises work programs. The following chart illustrates the overall expenditure trend from the 2016 OEB Approved level to the 2023 Test Year. Specific work programs are then discussed and variance explanations for material changes in the trend are provided.

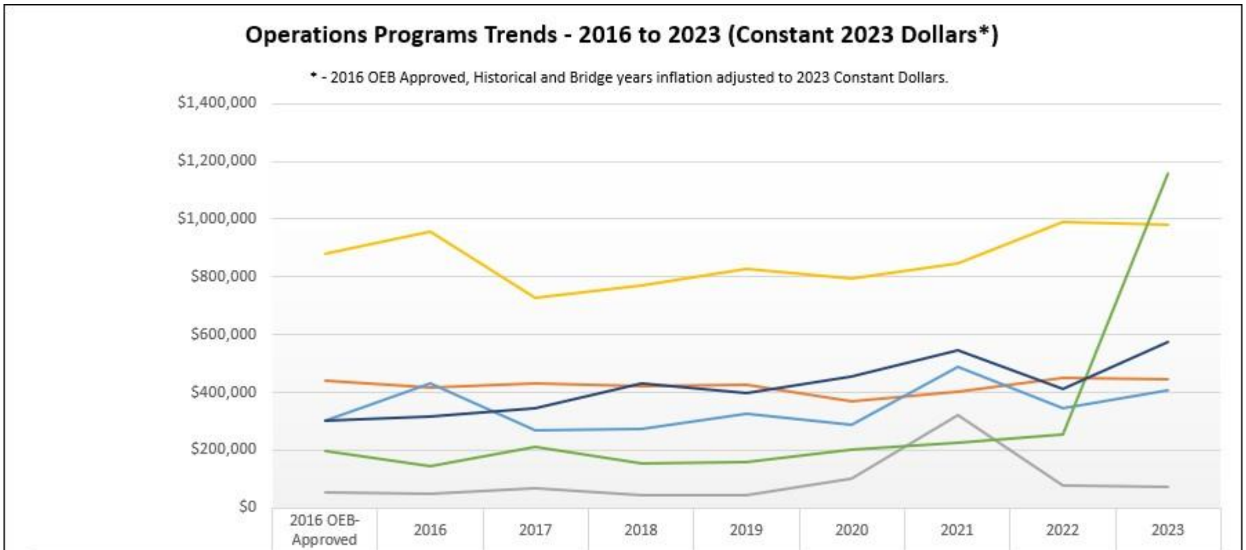
Chart 4.1. - Operations Cost Trend



	2016 OEB-Approved	2016	2017	2018	2019	2020	2021	2022	2023
Underground Locates	$380,000	$358,200	$378,024	$373,373	$383,562	$338,981	$379,451	$437,230	$443,788
Transformer Station	$48,528	$42,097	$59,666	$37,960	$42,166	$93,846	$302,383	$74,681	$75,536
Engineering Administration	$758,285	$820,851	$634,983	$682,566	$744,927	$730,575	$792,439	$959,438	$979,899
Stores Administration	$260,418	$368,816	$235,779	$241,891	$295,126	$262,309	$458,839	$332,446	$409,692
Control Room Services	$168,600	$124,646	$185,550	$138,600	$145,025	$184,650	$213,159	$247,100	$1,155,897
Customer Premise	$258,653	$271,661	$302,193	$382,742	$359,653	$418,959	$513,419	$400,418	$576,600

Milton Hydro has experienced the impact of cost inflation since 2016 rates were set. In order to help identify the impact of inflation from a change in underlying work volume, Milton Hydro has "normalized" expenditures from 2016 to 2022 to enable them to be seen on a 2023 Test Year constant dollar basis. As a proxy for the impact of inflation, Milton Hydro used the OEB issued inflation parameters established for annual Incentive Rate Mechanism adjustments and the 2023 inflation parameter is assumed to be the same 3.3% that was approved for the year 2022. The following chart presents the work program expenditure trends on a "normalized", 2023 Test Year constant dollar basis.

Chart 4.2. - Operations Cost Trend (Constant 2023 Dollars)



	2016 OEB-Approved	2016	2017	2018	2019	2020	2021	2022	2023
Underground Locates	$442,442	$417,060	$431,934	$421,562	$426,665	$369,681	$404,908	$451,659	$443,788
Transformer Station	$56,502	$49,015	$68,175	$42,860	$46,904	$102,345	$322,670	$77,146	$75,536
Engineering Administration	$882,887	$955,733	$725,538	$770,659	$828,639	$796,739	$845,603	$991,099	$979,899
Stores Administration	$303,210	$429,420	$269,403	$273,110	$328,291	$286,065	$489,622	$343,417	$409,692
Control Room Services	$196,304	$145,128	$212,011	$156,488	$161,322	$201,373	$227,460	$255,254	$1,155,897
Customer Premise	$301,155	$316,301	$345,289	$432,139	$400,069	$456,902	$547,864	$413,632	$576,600

It can be seen from the above charts that while costs for all Operations programs have increased over the 2016-2023 period, when normalized for inflation and stated on a 2023 constant dollar basis, increases are more modest. Even taking inflation into consideration, there is a large increase in Control Room Services due to bringing the function in-house. There are smaller increases in other program costs and these are discussed below.

4.3.2.1. Underground Locates

Key work activities in the Underground Locates program include providing highly visible paint marks continuously or at regular intervals on the surface of the ground to clearly indicate underground infrastructure owned by Milton Hydro as well as providing written records describing the locate information to excavators.

Homeowners and contractors are required by law (under the Occupational Health and Safety Act of Ontario) to determine the location of buried utilities before any excavation. The Regulation is intended to prevent injuries and property damage and helps to avoid expensive repairs and power outages for customers. The Locates work program provides location services for all utility owned underground plant installed as part of the electrical system in the Town of Milton.

Milton Hydro partners with the Ontario One Call system as mandated by the Ontario Underground Infrastructure Notification System Act, 2012. The volume of requests for location services has increased due to public awareness and demand due to town development. The public has become more aware of the safety issues and legal requirements for locates through "Call Before You Dig" advertising campaigns.

Milton Hydro's duties under the Act include but are not limited to:

- providing excavators with responses to excavation requests within five business days;
- reporting the completion of those locate responses to Ontario One Call within three business days; and
- ensuring Ontario One Call has factual up-to-date information.

Milton Hydro outsources its cable locating function to third party providers who process incoming requests and identify the location of Milton Hydro's underground infrastructure. The cost of the locate program includes the service fee to Ontario One Call and the cost of performing the locate, which varies depending on the nature of the locate requested.

Table 4-9 provides the expenditures on Underground Locates from 2016 to 2023.

Table 4-9 Underground Locates

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Underground Locates	$380,000	$358,200	$378,024	$373,373	$383,562	$338,981	$379,451	$368,598	$437,230	$443,788

Underground locate expenditures are relatively stable over the 2016 - 2023 period, with the work volume remaining steady and cost increases primarily due to inflation.

Planned 2023 Test Year expenditures are $443,788, and key initiatives include expenditures for direct labour and third-party services which are out of our control with customer volume and demand for this service.

4.3.2.2. Transformer Stations

The Transformer Stations program is responsible for the operations and maintenance of all equipment at Milton Hydro's four Municipal Stations (substations) that house substation power transformers. Milton Hydro's substation maintenance strategy focuses on minimizing, to the extent possible, emergency, reactive work by improving the effectiveness of Milton Hydro's planned maintenance program (including predictive and preventative actions) for its substations.

The Transformer Stations program conducts inspection and maintenance tasks typically on a fixed cycle and is focused on preserving and maximizing an asset's performance over its expected useful life while mitigating a wide variety of system risks. Inspections focus on predetermined conditions indicative of a potential failure.

The program includes planned, preventive, and unplanned corrective maintenance of Substation Power Transformers, Substation Switchgear, Breakers, Relays, and Remote Terminal Units (RTU) that communicate to the Supervisory Control and Data Acquisition ("SCADA"). Preventive maintenance performed on this equipment includes electrical, mechanical, and type-specific maintenance tasks.

The substations undergo a complete detailed preventive maintenance inspection at least once every year. Power Transformer maintenance includes oil analysis, electrical and mechanical maintenance. Breaker and Relay preventive maintenance work is carried out every three years and includes detailed internal visual inspection, insulation resistance tests, and confirmation that there are no structural deficiencies in breakers

During the inspection a record of the transformer's oil and winding temperature, transformer oil level is taken, and other findings are recorded. Planned annual thermographic (IR) scanning and DC systems (Batteries and Chargers) predictive maintenance is performed as well. Good utility practice guides Milton Hydro's scheduling of dissolved gas analysis testing; for example, the frequency of testing is greater for those transformers with higher levels of dissolved gas. This data is considered in combination to assess transformer 'health' and to identify the need and plan for maintenance activities. Additional expenditures incurred in this program include associated property tax and insurance.

Table 4-10 provides the expenditures on Transformer Stations from 2016 to 2023.

Table 4-10 Transformer Stations

Description	2016 OEB Approved	Historical Year 2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	Bridge Year 2022 Forecast	Test Year 2023 Forecast
Transformer Station	$48,528	$42,097	$59,666	$37,960	$42,166	$93,846	$302,383	$96,353	$74,681	$75,536

2023 Test Year expenditures are $226,847 lower than 2021 Actual, primarily due to a one-time environmental remediation work at 96 Bronte Street North in the amount of $196,000 that occurred in 2021.

Planned 2023 Test Year expenditures are $75,536, and key initiatives include: direct labour, direct materials, and vehicle expenditures to support the maintenance and servicing of station land and equipment, property insurance, and property taxes.

4.3.2.3. Engineering Administration

Engineering Administration costs are for labour and expenses incurred in the general supervision and direction of the operation and maintenance of the distribution system. Key work activities in the Engineering Administration program include supervising engineering and GIS staff, maintaining asset records, maintaining system maps including SCADA and OMS, developing, and managing asset inspection programs, system planning, and maintaining construction standards. This work program is also responsible for the development, implementation, and monitoring of the Distribution System Plan.

The Engineering Administration program is responsible for issuing service orders based on a predetermined schedule and through coordination with other Operations and Maintenance work programs. The department also processes operations, maintenance, and capital work orders, and associated locate requirements. This program also provides administration for all easement and liaison requests, developer correspondence, the record keeping process between Operations and GIS functions. This area also provides general administrative services for all Engineering and Operations departments and collects, reviews, and organizes OEB-required reporting data.

Milton Hydro’s information systems/GIS is the designated asset register for field assets and serves as an accurate model of Milton Hydro’s physical electrical distribution system. Milton Hydro’s GIS asset database is the source data that supports the Asset Condition Assessment (ACA) process as well as Milton Hydro’s capital planning process. Asset data in the GIS is captured from a multitude of sources including, but not limited to construction records and legacy records. Annual inspection and maintenance program results including inspection dates, and maintenance records are stored outside the GIS. Through on-site planned inspections or maintenance, the asset data is verified and corrected as required. The GIS contains asset attribute information such as location, type, installation/removal year, installation/removal work order, third party attachment information, etc.). The GIS aids in cost control through optimization of inspection and maintenance programs. The GIS is also available to staff on their mobile devices.

This program also provides support for Operations staff and the Control Room (whether “outsourced” or “in-house”). The program is also responsible for receiving inbound calls from contractors, customers, and Milton Hydro staff into the Outage Management System (OMS). At the time of an outage, the OMS analyzes the trouble calls and proposes outage devices for field crews to quickly troubleshoot and restore power.

Combined with the OMS is the SCADA system which monitors the real-time operation of the distribution. SCADA aids in troubleshooting, thus reducing the time and cost in addressing service issues. Real-time breaker status, voltage and current readings from the four transformer stations and two municipal substations are monitored and displayed through the SCADA system. The SCADA also enables Control Room Operators to remotely control field devices for quick and safe operations of the distribution network. It tracks work protection record and provides safe conditions for crews doing work on the system.

Mobile equipment is being put into use to develop a mobile workforce that provides paperless access to GIS information, maps, schematics, drawings and standards for inspection crews, line staff, and Operations supervisors. Immediate access to data helps streamline utility operations and ensure crew safety in executing capital projects or day to day operations.

The Engineering group is also responsible to ensure material and construction standards, and processes are maintained and developed as required to meet current code requirements including Ontario Regulation 22/04 Electrical Distribution Safety

Table 4-11 provides the Engineering Administration expenditures from 2016 to 2023.

Table 4-11 Engineering Administration

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Engineering Administration	$758,285	$820,851	$634,983	$682,566	$744,927	$730,575	$792,439	$734,390	$959,438	$979,899

2023 Test Year expenditures are $221,614 higher than 2016 OEB Approved, primarily due to: (i) cost increases of $124,602 associated with annual inflation; (ii) an increase of $43,445 in direct labour expenditures associated with hiring of an Engineering Technician to support the increased projects in a rapidly growing community; and (iii) higher direct vehicle charges of $42,000 corresponding to the higher utilization of fleet assumed in the 2016 OEB Approved application.

2023 Test Year expenditures are $187,460 higher than 2021 Actual, primarily due to: (i) cost increases of $53,164 associated with annual inflation; (ii) an increase of $43,445 in direct labour expenditures associated with hiring of an Engineering Technician to support the increased projects in a rapidly growing community; (iii) higher direct vehicle charges of $42,000 corresponding to the higher utilization of fleet assumed in the 2016 OEB Approved application; and (iv) lower allocation of labour to capital in 2021 Actual corresponding to increased focus of resources supporting the cost of service rate application for $31,000.

2023 Test Year expenditures are $245,509 higher than the average of the 2016 to 2021 Actual, primarily due to: (i) cost increases associated with annual inflation; (ii) an increase in direct labour expenditures associated with hiring of an Engineering Technician to support the increased projects in a rapidly growing community; and (iii) higher direct vehicle charges corresponding to the higher utilization of fleet assumed in the 2016 OEB Approved application.

Planned 2023 Test Year expenditures are $979,899, and key initiatives include: direct labour and vehicle expenditures to support engineering operations and design; administrative and support costs related to training and development, ESA fees communication costs, and an allocation of Information Technology support costs.

4.3.2.4. Stores Administration

Key work activities in the Stores Administration program include the procurement of material and services; administration of procurement policies; receiving and warehousing of materials and supplies; and management of the inventory and equipment used to construct and maintain Milton Hydro's distribution assets.

Milton Hydro constantly searches ways to minimize costs and improve efficiencies through collaboration, with groups such as Cornerstone Hydro Electric Concepts ("CHEC") group, neighboring utilities, or purchasing cooperatives (e.g., Grid Smart City). Milton Hydro is always seeking economies of scale and scope opportunities. Milton Hydro reduces costs by obtaining price discounts through volume purchasing of commonly used products. Supplier alliances have also been established with many vendors, representing a substantial percentage of the product being used in the Company's distribution system. The material supplied by these vendors covers most categories of inventory including transformers, cable and wire. The alliances have resulted in lower costs due to volume purchasing over a long period of time, reduced administrative efforts, and lower inventory carrying costs

The Stores Administration program ensures that Milton Hydro follows best practices with respect to the procurement of goods and services. Adherence to written policy helps to ensure that competitive prices for products and services are obtained in a consistent and unbiased manner and that consistent selection criteria guide the bid evaluation process.

Purchasing transactions are initiated and processed in accordance with authorization levels detailed in the Company's approved signing authority register.

The Stores Administration program warehouses inventory, supplies and material used for capital projects, billable services and operating and maintenance activities. Inventory is kept on hand to be is readily available in an efficient and timely manner. Inventory includes poles, cable, wire, reels, concrete products, transformers and other distribution equipment.

The Stores group consists of two General Labourer positions and one Material Handler. Duties of the group include:

a. keeping a record of, and maintaining cycle counts for the complete inventory;

b. receiving inventory and verifying with the manifests, purchase order listings and material specifications;

c. maintaining proper documentation processed for the receipt of the good and supplies;

d. sorting all goods and stocking them appropriately;

e. labelling, tagging and packaging of the goods;

f. ensuring the timely dispatch of the goods to the appropriate destinations and recording appropriate charge numbers;

g. coordinating and synchronizing work functions with the vendors, suppliers and other internal groups of Milton Hydro;

h. maintaining cleanliness and order in the workplace and complying with all safety practices while carrying out work functions, and

i. assisting with recycling initiatives to reclaim more material for recycling and reduce material sent to landfill.

Table 4-12 provides the expenditures on Stores Administration from 2016 to 2023.

Table 4-12 Stores Administration

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Stores Administration	$260,418	$368,816	$235,779	$241,891	$295,126	$262,309	$458,839	$310,460	$332,446	$409,692

2023 Test Year expenditures are $149,274 higher than 2016 OEB Approved, primarily due to: (i) the addition of a General Labourer at a cost of $56,000 to support the day-to-day stores operations; (ii) cost increases of $42,792 associated with annual inflation; and (iii) direct material costs of $35,000 related to the operations maintenance program.

Planned 2023 Test Year expenditures are $409,692, and key initiatives include: direct labour charges to oversee and issue materials to support capital, operations, and maintenance programs; third-party waste management services to dispose of hazardous materials; direct materials to support stores operations; and postage and delivery costs.

4.3.2.5. Control Room Services

The Control Room Services program is responsible for the monitoring, control, and ongoing management of the distribution network with the objective of maintaining a safe and reliable supply of service for customers. This program oversees the configuration of the grid through defined switching operations. This program is also responsible for receiving inbound calls from contractors, customers and Milton Hydro employees and dispatching related troubled calls to Operations crews.

important initiative for Milton Hydro is to bring the Control Room "in-house" and no longer depend on a third party for control room services. Key work activities in the Control Room program include operating the distribution system, issuing work permits to ensure crew safety, and customer engagement during planned and unplanned outages.

The primary objective of bringing Milton Hydro’s control room “in house” is the safe and reliable operation of Milton Hydro’s distribution system. This will be accomplished with a full complement of system operators that provide and ensure safe work protection for Milton Hydro’s employees, its contractors and the public.

The Control Room will be responsible for system monitoring, outage management (outage planning for construction and maintenance, dispatching, restoration efforts and event tracking), security monitoring, reviewing and preparing switching orders, communicating with Hydro One Ontario Grid Control Center, updating records and communicating with contractors and customers regarding outages.

Milton Hydro’s Control Room will be staffed 24 hours a day, 7 days a week and is linked to the distribution system by a data communication network. Information is processed by a SCADA system and Outage Management System (OMS) . Real-time breaker status, and voltage and current readings from four Hydro One transformer stations, 1 municipal transformer station, four Milton Hydro substations as well as 70 smart switches will be communicated to the Control Room and displayed on the SCADA system. Milton Hydro’s Control Room operators will continuously monitor the distribution system, relying on automated devices such as overhead switches and switchgear. Additionally, there are smart fault indicators which report faults on the system when and where they occur. The Control Room and these devices support system operations, and when necessary, dispatch repair/trouble crews to manage equipment failures. The Control Room will also co-ordinates field work to establish and preserve work protection and safe conditions for crews doing work on the system.

Milton Hydro currently outsources Control Room services to a third-party service provider. These services include monitoring of the transformer stations, fault indications as well as monitoring and control of the municipal stations and smart switches.

Control Room monitoring can be used for a wide variety of beneficial functions. Though expanded functionality falls into the “discretionary” category, enhanced control room monitoring would result in operational efficiencies and improvements in the key corporate goals of safety and reliability. Milton Hydro has explored options and retained an external consultant to evaluate options regarding maintaining the outsourcing of Control Room services or bringing them “in house”. The resulting report can be found as Exhibit 4.4 Attachment 4-1 “Business Case: 24/7 System Control Room & Operations". The report found that the benefits of a Control Room can include improvements to employee and contractor safety, outage and trouble call response and customer engagement.

The report defined the following control room functions:

• Participation in Major Outage Recovery

• Work Crew Dispatch/Coordination.

• Centralized Command Center

• Communication Center

• Operational Control of devices at Transmission Impacted Facilities

• Issuance of Work Permits (WPs) and work protection guarantees

• Tracking and updating status of Hold-offs, and

• Preparation and Overview of “Order to Operate” (OTO’s) for normal work

Table 4-13 provides the expenditures on Control Room Services from 2016 to 2023.

Table 4-13 Control Room Services

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Control Room Services	$168,600	$124,646	$185,550	$138,600	$145,025	$184,650	$213,159	$165,272	$247,100	$1,155,897

2023 Test Year expenditures are $987,297 higher than 2016 OEB Approved, primarily due to the addition of a 24/7 Control Room beginning in 2022 and fully operational in 2023. The investment in an in-house control room will provide improved 24/7 coverage of the system to enable reconnecting the power grid faster, and position Milton Hydro to be ready to act as a Distribution System Operator (DSO) as many new Distributed Energy Resources ("DERs") connect to the distribution system. The business case for the Control Room being brought "in house" can be found in Exhibit 4.4 Attachment 4-1.

Planned 2023 Test Year expenditures are $1,155,897, and key initiatives include: the direct labour expenditures for six (6) control room operators plus support services and administration in support of having a dedicated control room facility. Labour expenditures represent 90.4% of the overall costs in Control Room Services.

4.3.2.6. Customer Premise

Key work activities in the Customer Premise program include temporary customer service disconnection requests and trouble calls.

The Customer Premise program is primarily composed of planned customer requested service disconnection and reconnection for work being done by the customer such as a panel upgrades and responding to unplanned trouble calls for part power, no power, and service quality issues.

Table 4-14 provides the expenditures for Customer Premises from 2016 to 2023.

Table 4-14 Customer Premise

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Customer Premise	$258,653	$271,661	$302,193	$382,742	$359,653	$418,959	$513,419	$374,771	$400,418	$576,600

2023 Test Year expenditures are $317,947 higher than 2016 OEB Approved, primarily due to: an increase in customer demand resulting in higher resourcing required to service these customers; increase in customer growth; higher allocation of labour to operating activities from the lines crew to service these requests relative to those assumed in the 2016 OEB Approved. Milton Hydro has seen the increase in renewal and renovation, increasing of service sizes, and the electrification of vehicles has changed the anticipated operating requirements to service Customer Premise programs.

2023 Test Year expenditures are $201,829 higher relative to the average of 2016 to 2021 actual, primarily due to: an increase in customer demand resulting in higher resourcing required to service these customers; increase in customer growth; higher allocation of labour to operating activities from the lines crew to service these requests relative to those assumed in the 2016 OEB Approved. Milton Hydro has seen the increase in renewal and renovation, increasing of service sizes, and the electrification of vehicles has changed the anticipated operating requirements to service Customer Premise programs.

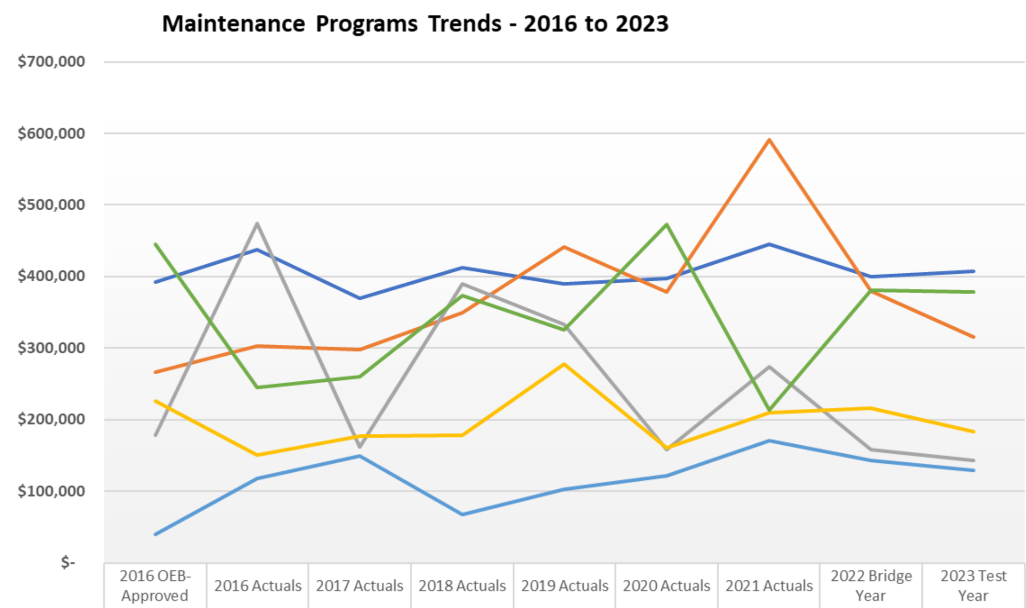
2023 Test Year expenditures are $176,182 higher than 2022 Bridge Year costs, primarily due to increase in customer demand resulting in higher resourcing required to service these customers. At the time the 2022 Bridge Year was developed, the trends experienced in 2021 were significantly higher than originally anticipated. Subsequently, the 2023 Test Year costs were aligned to include trends experienced in renewal and renovation, increasing of service sizes, and the electrification of vehicles.

Planned 2023 Test Year expenditures are $576,600, and key initiatives include: regular program support and the planned allocation of a line person to manage and complete work based on customer requests.

4.3.3. Maintenance Work Programs

The Maintenance category is comprised of Meter Maintenance, Overhead Lines, Pole maintenance, Maintenance of Line Transformers, Underground Lines and Tree Trimming work programs. Chart 4.3 illustrates the overall expenditure trend from the 2016 OEB Approved level to the 2023 Test Year. Specific work programs are then discussed and variance explanations for material changes in the trend are provided.

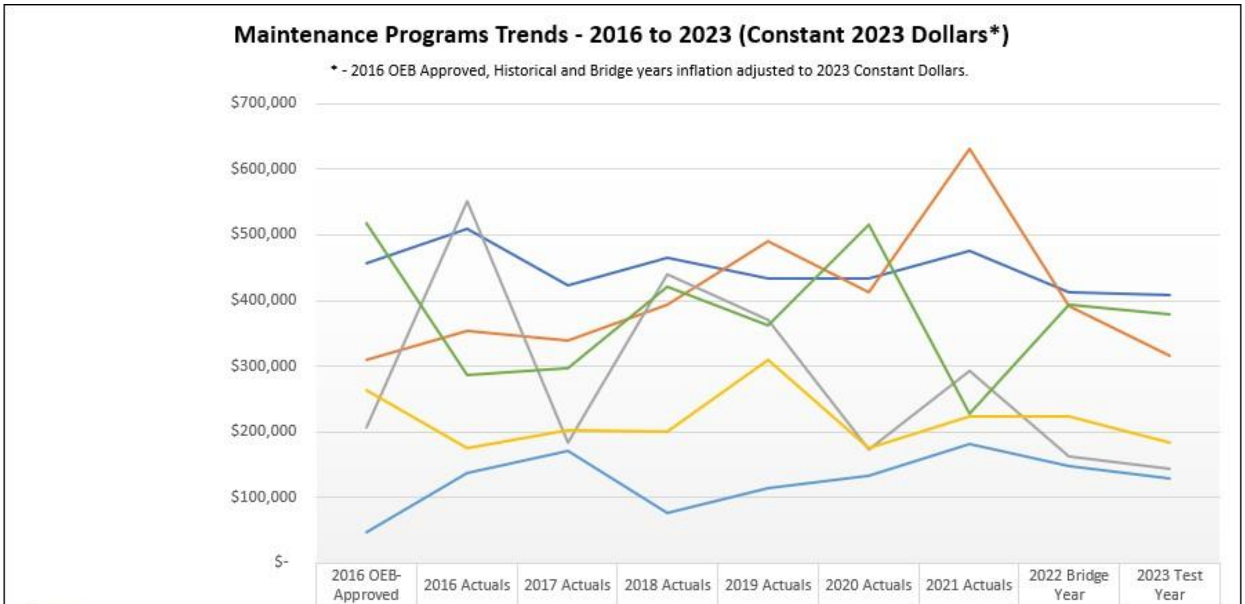
Chart 4.3. Maintenance Cost Trend



	2016 OEB-Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Meter Maintenance	$392,437	$437,655	$369,993	$412,303	$389,427	$396,814	$445,148	$399,934	$407,808
Overhead Lines	$266,754	$303,099	$297,263	$349,235	$440,735	$378,090	$591,491	$379,311	$314,936
Pole Maintenance	$177,726	$473,535	$161,499	$389,879	$333,646	$157,965	$273,722	$157,495	$142,644
Maintenance of Line Transformers	$225,972	$150,213	$176,479	$178,194	$278,315	$161,041	$209,203	$215,682	$183,345
Underground Lines	$39,714	$118,052	$148,734	$67,439	$103,220	$121,306	$170,264	$143,081	$129,133
Tree Trimming	$445,522	$245,358	$259,508	$373,691	$325,314	$473,379	$213,394	$381,227	$378,981

Chart 4.4 presents the above trends on a "normalized" basis. Using the OEB approved inflation factor, annual expenditures are escalated in order to present information on a 2023 Test Year constant dollar basis.

Chart 4.4. Maintenance Cost Trend (Constant 2023 Dollars)



	2016 OEB-Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Meter Maintenance	$456,922	$509,571	$422,758	$465,516	$433,189	$432,751	$475,013	$413,132	$407,808
Overhead Lines	$310,587	$352,904	$339,656	$394,308	$490,263	$412,332	$631,174	$391,828	$314,936
Pole Maintenance	$206,930	$551,347	$184,530	$440,197	$371,140	$172,271	$292,086	$162,693	$142,644
Maintenance of Line Transformers	$263,104	$174,896	$201,647	$201,192	$309,591	$175,625	$223,238	$222,800	$183,345
Underground Lines	$46,240	$137,450	$169,945	$76,143	$114,819	$132,292	$181,686	$147,803	$129,133
Tree Trimming	$518,730	$285,675	$296,517	$421,920	$361,872	$516,251	$227,710	$393,807	$378,981

It can be seen from the above charts that maintenance program costs, while fluctuating during the 2016 to 2023 period have had only a modest increase in expenditures over this period. In some instances, expenditures deceased (e.g. pole maintenance and tree trimming). On a normalized 2023 constant dollar basis, costs for all maintenance programs decrease, with the exception of a $83,000 increase in the underground lines work program. This cost performance has been achieved as the number and value of assets to be maintained has increased over the same period.

4.3.3.1. Meter Maintenance

The Meter Maintenance program is responsible for purchasing and installing metering equipment which Milton Hydro relies upon to record electricity consumption and demand for billing and market settlement purposes. This program includes Metering Services which is responsible for maintaining and testing metering equipment to ensure proper functionality and compliance with applicable legislative and regulatory requirements. Meter testing is a requirement under the Electricity and Gas Inspection Act (R.S.C., 1985, c. E-4) (“Electricity and Gas Inspection Act”) enforced and administered by Measurement Canada.

Metering is one of the most fundamental activities for a distribution company and the implementation of Smart Meters has had a significant impact on this Program. In addition to a complete transition from an 'analog' to a 'digital' meter environment, the Meter Maintenance Program has also assimilated three new technology streams: wireless communications, data system management and customer facing applications, all based on new digital technologies.

The Meter Maintenance work program is responsible for the installation, testing, and commissioning of new metering and for the ongoing operations of existing metering, both simple and complex metering installations. Testing of complex metering installations ensures the accuracy of the installation (e.g., to verify that the appropriate meter multipliers are applied through the billing process). The scope of work also includes investigation of potential stopped meters, diversion and/or theft of power which may give rise to unsafe conditions or cause other customers to be inappropriately held financially responsible for overall costs.

The metering program benefits customers in two ways:

1. The ongoing accurate operation of meters provides real time operating data to SCADA and other systems that support Systems Operations, and

2. Ensuring that bills are computed correctly, therefore ensuring that customers are fairly charged for the services received.

Milton Hydro's Metering Maintenance group ensures accurate and compliant metering, Meter reading, and other services to ultimately support accurate billing. These programs have ensured that Milton Hydro has maintained a billing accuracy target on the OEB performance scorecard of >98% since 2017 with an improving trend. Smart Meters have also become a foundational data source for other operational processes (i.e., outage data, voltage data), customer consumption and demand data made available through self-serve online portals and the Green Button Download My Data ("DMD") and Connect My Data ("CMD") interfaces. The goal of Milton Hydro's Meter Maintenance Program is to install, maintain and operate utility metering, sensors, information and communications technology to support an enhanced utility, industry and end-use customer experience.

Metering Services' operations includes a full scope of activities starting with measuring energy flows within the Milton Hydro system, both purchases and distribution, to providing individual customer usage amounts for billing and revenue collection.

Four basic activities comprise the Metering mandate:

- Metering - to measure electricity flows
- Communications - collection of the metered data
- Data Management - validation, analysis, and storage of the collected data
- Applications and Support - customer engagement through the delivery of the approved data to the customer and other users.

The Meter Maintenance program supports over 42,000 smart, suite, commercial and industrial meter installations within Milton Hydro's licensed service territory. The program supports new and existing customers with installs, exchanges, and removals. For example, in 2021, Milton Hydro completed over 2,400 new meter installations and installed over 120 new large commercial services.

Milton Hydro's Meter Maintenance group is certified to the ISO 9001:2015 Standard and the principles are embedded in the department's quality management system. This management system ensures high quality accurate billing for utility customers. This program seeks to realize OEB Renewed Regulatory Framework performance outcomes in the areas of Customer Focus and Operational Effectiveness. Accurate metering and billing underpin ratepayer trust and confidence in the entire electricity system and supports Milton Hydro's brand image as a credible utility.

In addition, metering reverifications increased over the past few years to successfully accomplish the Measurement Canada Compliance Sample program. The increase in meter reverifications is due to the mass installation of smart meters in the 2009 to 2012 period which became due for their 10-year meter seal refresh between 2019 and 2022. Milton Hydro has invested in meter sealing capability and capacity enhancements to manage this surge. Preparing for this work was a multi-year effort and included building a strong internal team to execute the work program.

Milton Hydro has partnerships and contracts with third party metering specialists in suite metering for multi-residential buildings, and wholesale metering for its registered Wholesale Meter points with the Independent Electricity System Operator ("IESO"). The Metering program also performs in field checks of its metering installations.

These field checks consist of two parts; a static test, and a dynamic test:

- The static test involves a visual review of the instrument transformer serial numbers, ratios, meter information, meter type, wiring, grounding, condition of cabinets, evidence of tampering, by-passed conductors, loose connections and any other safety issues.

- The dynamic test involves the physical connections of test equipment (circuit analyzer), the take voltage, current, power and phase angle measurements to verify that instrument transformer ratios and billing multipliers are correct. The primary objective of the Meter Program is to maintain an accurate meter population that provides accurate data for billing purposes and provides added value by using hourly data for engineering and operations purposes such as loading calculations, and power outage and power restoration information. This objective is accomplished through meter service technicians that are proficient in power system calculations, knowledge of communication systems and cellular technology and safe operations around energized equipment. Qualified staff are able to detect theft, errors and safety issues that arise.

Table 4-15 provides the expenditures on Meter Maintenance from 2016 to 2023.

Table 4-15 Meter Maintenance

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Meter Maintenance	$392,437	$437,655	$369,993	$412,303	$389,427	$396,814	$445,148	$408,557	$399,934	$407,808

Meter maintenance expenditures are relatively stable over the 2016 - 2023 period, with the work volume remaining steady and costs have increased at less than the rate of inflation.

Planned 2023 Test Year expenditures are $407,808, and key initiatives include: direct labour charges for metering technicians and supervisory oversight; third party support meter maintenance support for meter verification; and direct materials.

4.3.3.2. Overhead Lines

A significant portion of Milton Hydro's distribution system includes overhead lines. The entire three phase overhead system is inspected annually using infrared thermography scanning and on a three-year rotational basis using visual inspection. The purpose of the thermographic inspections are to identify any issues due to weakened connections and remediate them as quickly as possible to ensure continuous operation of the distribution system. Maintenance of overhead conductors includes primary and secondary wires. Milton Hydro continuously inspects and monitors its poles and fixtures to assess their condition and need for repair or replacement. As part of that inspection process, some components are identified for maintenance work.

The Overhead Lines program is responsible for the maintenance involved in ensuring that customers' overhead services are connected, repaired, or maintained in a prompt and efficient manner and that overhead system maintenance is completed as scheduled. The program is responsible for the overall management of line crews and contractors who execute the design plans of the Engineering Administration department for Milton Hydro's overhead distribution system. The work of the Operations group is critical for minimizing the need for reactive and emergency work through an effective and proactive planned maintenance program (including predictive and preventative actions), which minimizes customer outages and avoids potential costly repairs or replacements should equipment fail catastrophically. When reactive and emergency work is required, it is often performed outside of normal working hours which results in higher costs due to overtime required. The Operations group follows the asset management program described above to monitor and track infrastructure inspection activities. These inspections are complemented using contractor services.

Milton Hydro's strategy is to provide safe, reliable service at an appropriate level of quality and cost throughout its' license service area. Milton Hydro's maintenance strategy is an important part of its overall strategy of minimizing the life cycle costs of assets by minimizing reactive and emergency-type work, through planned maintenance programs (including predictive and preventative actions).These strategies are implemented through work practices that promote a good experience for the customer with regard to safety, security of supply, reliable continuity of service, the timely restoration of service and the minimization of undesirable service conditions. Milton Hydro's customers receive high quality services and customers see that the system is in a state of good repair, that crews are engaged in inspection, testing, cleaning, and verification activities.

Table 4-16 provides the expenditures on Overhead Lines from 2016 to 2023.

Table 4-16 Overhead Lines

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Overhead Lines	$266,754	$303,099	$297,263	$349,235	$440,735	$378,090	$591,491	$393,319	$379,311	$314,936

Overhead lines expenditures are relatively stable over the 2016 - 2023 period, with the work volume remaining steady and costs have increased consistent with the rate of inflation, with the notable exception of 2021 where costs were higher primarily due to: (i) the accounting treatment of involuntary terminations in the Lines department in 2021; and (ii) higher than anticipated overtime expenditures resulting from planned, reactive and emergency work. In 2022 and 2023, expenditures return to a stable level.

Planned 2023 Test Year expenditures are $314,936, and key initiatives include: labour for overhead line activities; communication equipment expenditures; direct material and vehicle charges; and third-party services to support after hours outage management.

4.3.3.3. Pole Maintenance

Key work activities in the Pole Maintenance program include pole inspection, treatment, and testing.

Milton Hydro tests its wood poles on an annual basis to facilitate the proactive replacement of wood poles in poor and very poor condition. Wood poles are tested after 25 years in service and every 6 years thereafter. Defective poles are identified for replacement based on condition. Poles that are in urgent need of replacement are replaced immediately with the remainder planned for replacement the following year.

Milton Hydro's service territory is split into three areas. The visual inspections and pole testing are completed on a three-year cycle.

Table 4-17 provides the expenditures on Pole Maintenance from 2016 to 2023.

Table 4-17 Pole Maintenance

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Pole Maintenance	$177,726	$473,535	$161,499	$389,879	$333,646	$157,965	$273,722	$298,374	$157,495	$142,644

2023 Test Year expenditures are $155,730 lower than the average of 2016 to 2021 Actual, primarily due to higher pole removals related to city road widening work experienced in the historical reporting periods.

2023 Test Year expenditures are $131,078 lower than 2021 Actual, primarily due to higher pole removals related to the city road widening work on Steeles Avenue between Martin Street and Industrial Drive experienced in 2021.

Planned 2023 Test Year expenditures are $142,644, and key initiatives include: third-party pole maintenance services and direct labour charges by lines staff.

4.3.3.4. Maintenance Line Transformers

Key work activities in the Maintenance Line Transformers program include inspections, maintenance, and repairs.

Milton Hydro owns and operates approximately 6,400 distribution transformers. Visual inspections are performed on a 3-year cycle. Milton Hydro line transformer maintenance consists of activities including items such as shifting padmounted transformers back into place, replacing rusted padmounted transformer skirts, repairing damaged access hatches for submersible transformers, replacing damaged disconnect switches, replacing damaged or missing ground wires, and replacing blown lighting arresters and fuses that operated as designed to protect the transformer from damage due to system issues.

Table 4-18 provides the expenditures on Maintenance of Line Transformers from 2016 to 2023.

Table 4-18 Maintenance Line Transformers

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Maintenance of Line Transformers	$225,972	$150,213	$176,479	$178,194	$278,315	$161,041	$209,203	$192,241	$215,682	$183,345

Maintenance of Line Transformers expenditures trend downward over the 2016 - 2023 period in response to maintenance work required. Overall, the work volume has remained steady and costs in 2022, 2023 respectively more than offsetting the impact of annual inflation.

Planned 2023 Test Year expenditures are $183,345, and key initiatives include: direct labour charges by lines staff; and third-party support to emergency or after-hours requirements.

4.3.3.5. Underground Lines

The Underground Lines program includes the repair of underground secondary cable failures where conductors have faulted (typically at a splice point) and require excavation to expose the problem area and repair. The program also includes the inspection, infrared testing and cleaning of pad mounted switchgear. Inspections and dry ice cleaning of switchgear is performed on a three-year cycle. Infrared testing is performed annually to detect any hotspots or contamination issues. If issues are detected, dry ice cleaning is performed on an as required basis.

Table 4-19 provides the expenditures on Underground Lines from 2016 to 2023.

Table 4-19 Underground Lines

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Underground Lines	$39,714	$118,052	$148,734	$67,439	$103,220	$121,306	$170,264	$121,503	$143,081	$129,133

Overall, there has been an increase in the cost of the Underground Lines work program due to recognition that the 2016 OEB Approved amount of $39,714 was insufficient to responsibly manage Underground lines maintenance activities. With the recognition of this required investment, expenditure levels have remained essentially consistent over the 2016 - 2023 period, well below the materiality threshold.

Planned 2023 Test Year expenditures are $129,133, and key initiatives include: direct labour charges by lines staff; and third-party support to emergency or after-hours requirements.

4.3.3.6. Tree Trimming/Vegetation Management

Milton Hydro performs vegetation management on 27 overhead primary feeders extending almost 611 circuit kilometers along Milton's arterial thoroughfares, rights-of-way, and residential streets.

These feeders co-exist with the Town of Milton's mature and dense tree canopy which is located predominantly in the north end of Milton.

Milton Hydro conducts trimming of vegetation near overhead feeders to proactively reduce the number of power interruptions caused by tree contacts. Planned vegetation management activities are executed on a 3-year cycle by contractors with support from Milton Hydro's internal resources. To ensure tree related power quality issues are minimized, Milton Hydro has adopted tree trimming requirements that include:

1) Minimum trimming requirements that incorporate tree growth rates and tree trimming cycle times to prevent trees from growing into power lines prior to the next trimming cycle.

2) Clearance requirements that differentiate between branches and tree trunks (with no branches).

3) A requirement to remove any diseased or other high-risk trees that may fall onto Milton Hydro's power lines (including trees beyond the minimum clearance requirements).

In addition to the minimum clearance standards, Milton Hydro considers other factors such as:

a. Species and growth patterns of a tree: fast-growing trees are trimmed more and slow-growing trees are trimmed less;

b. Natural trimming practices: branches are pruned back to a natural point of growth in the crown of the tree and leaders are "trained" (shaped) to grow away from the lines;

c. Distance of major limbs that exhibit minimal growth, versus minor branches that can exhibit aggressive growth;

d. Directional pruning practices: maintenance of tree shape and branch patterning;

e. Overall aesthetics and balance of the tree;

f. Removal of dead limbs; and

g. Storm hardening: select removal of branches within the canopy to minimize the possible effects of wind and severe weather but maintain the overall tree appearance.

Milton Hydro avoids the practice of “tree topping”, which is the indiscriminate removal of branches to reduce the size of the tree crown. As a result, and given the above-noted factors, Milton Hydro mandates the use of certified utility arborists for vegetation management activities with training, knowledge, and certification in the practice of arboriculture.

Vegetation management mitigates the risk of vegetation interference by pruning trees near Milton Hydro’s overhead feeders. Vegetation interference is one of the most common causes of power interruptions, as overhead feeders are prone to tree branch contacts. Trees may make contact with distribution feeders as a result of natural growth, or when severe weather causes branches to break and fall onto lines or to bend and make intermittent contact. Conductors also sag due to ice and snow build-up, heavy loading, or warm weather, bringing the lines closer to tree limbs below. Branch contacts with lines result in a new path for current to travel causing the branch to become energized which poses a safety risk.

Vegetation-related power interruptions can have a significant impact on system reliability if not mitigated through vegetation management. On average, during the years 2016 – 2020, 8% of outages were a result of tree contact. This excludes interruptions that occurred on major event days. During such days, the distribution system is particularly vulnerable to tree contacts and costly tree damage.

As time passes since the last tree pruning for a particular area, it becomes more likely that tree contacts will occur and associated risks will increase (including system reliability, financial, and safety risks). These risks can be effectively mitigated through vegetation management.

Vegetation management is also a widely accepted means of effectively “storm-hardening” a system (i.e. proactively mitigating against storm damage and associated system reliability risks). Storm hardening involves selectively removing portions of a tree canopy to reduce the “sail effect” of branches during high winds and to reduce the likelihood that broken branches will make contact with lines. As such, more frequent tree pruning further reduces risks posed by severe weather.

In many cases, the effects of these storms continue well after the storm has passed. Broken and weakened trees and tree limbs continue to pose a threat to overhead lines until the tree is pruned. In addition to maintaining system reliability, proper vegetation management can mitigate safety risks, such as trees and vegetation that grows or is blown into power lines. This vegetation can become energized, and in certain situations, can cause fires or cause 'step and touch' potential risks to the general public. Another safety risk stems from branches or trees that bring energized conductors to the ground when they fall, which pose significant safety hazards to the public. Vegetation management helps to mitigate these risks.

Milton Hydro awards the vegetation management contract through a competitive tendering practice and aims to achieve completion of work in each section during January to May prior to commencement of foliage growth. The advantage of completing vegetation management earlier in the year mitigates heavy foliage growth which can increase damage to limbs and consequently overhead infrastructure, causing longer power interruptions and higher costs to repair.

Milton Hydro identifies its three vegetation management sections in Figure 4-1.

Figure 4-1 Tree Trimming Areas

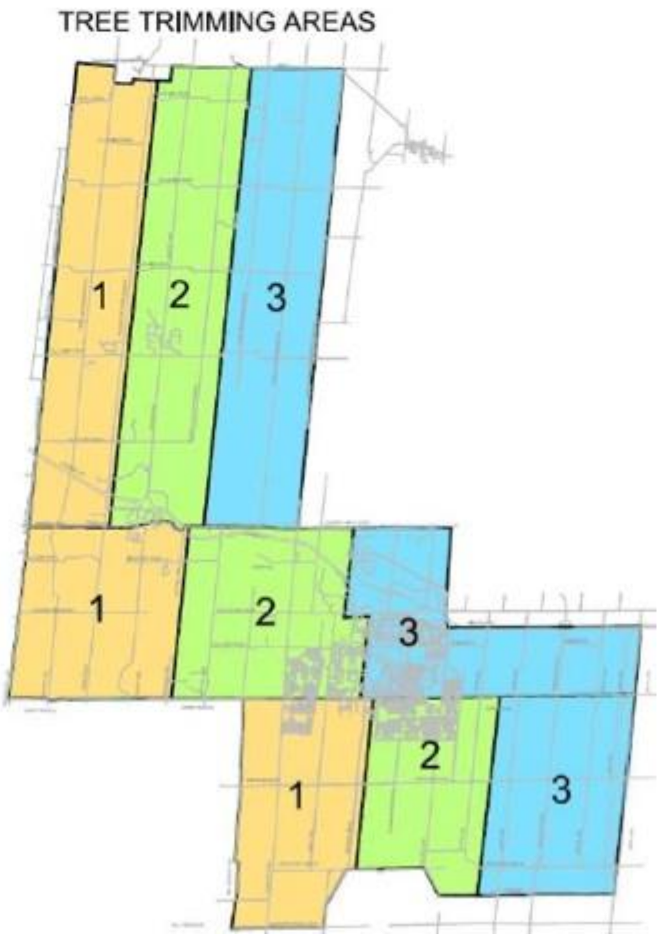


Table 4-20 provides the expenditures on Tree Trimming from 2016 to 2023.

Table 4-20 Tree Trimming

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Tree Trimming	$445,522	$245,358	$259,508	$373,691	$325,314	$473,379	$213,394	$315,107	$381,227	$378,981

2023 Test Year expenditures are $165,587 higher than 2021 Actual, primarily due to: (i) the availability of the tree trimming vendor and completion of planned grids; and (ii) lower reactive tree trimming expenditures resulting from fewer extreme weather events incurred.

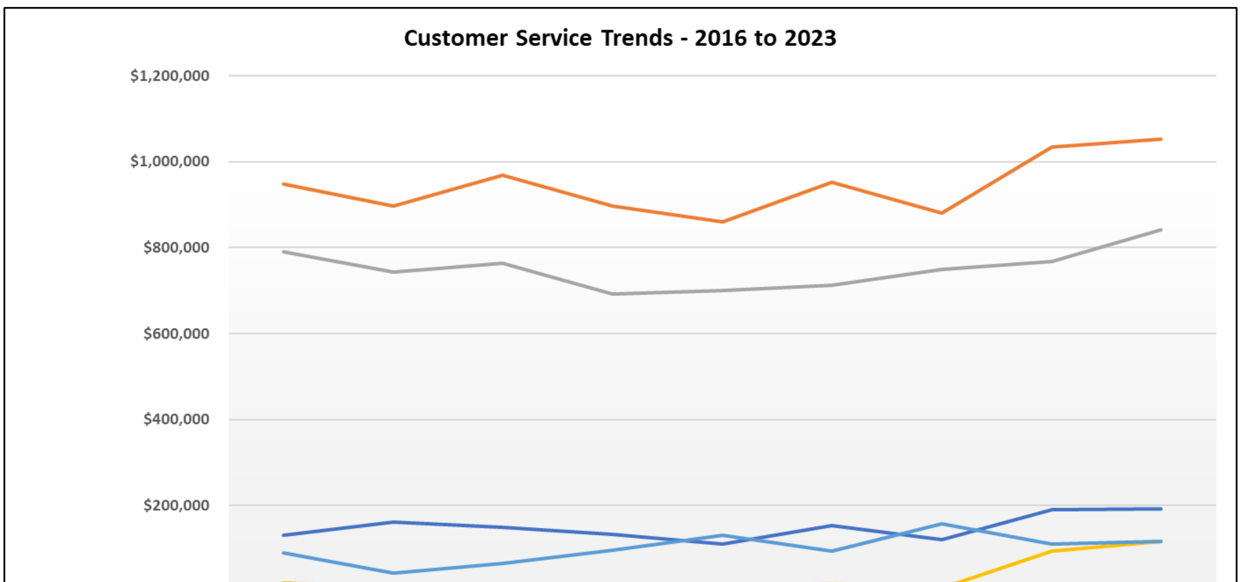
The annual level of expenditure in the 2016-2023 period is less than the 2016 OEB approved amount due to re-evaluation of the approach to tree trimming in Milton and the associated procurement process.

Planned 2023 Test Year expenditures are $378,981, and key initiatives include: direct labour charges, third party support costs and direct materials.

4.3.4. Customer Service Work Programs

The Customer Service category is comprised of Meter Reading, Billing, Customer Service, Community Relations, and Bad Debt work programs. The following following Chart 4.5 illustrates the overall expenditure trend from the 2016 OEB Approved level to the 2023 Test Year. Specific work programs are then discussed and variance explanations for material changes in the trend are provided.

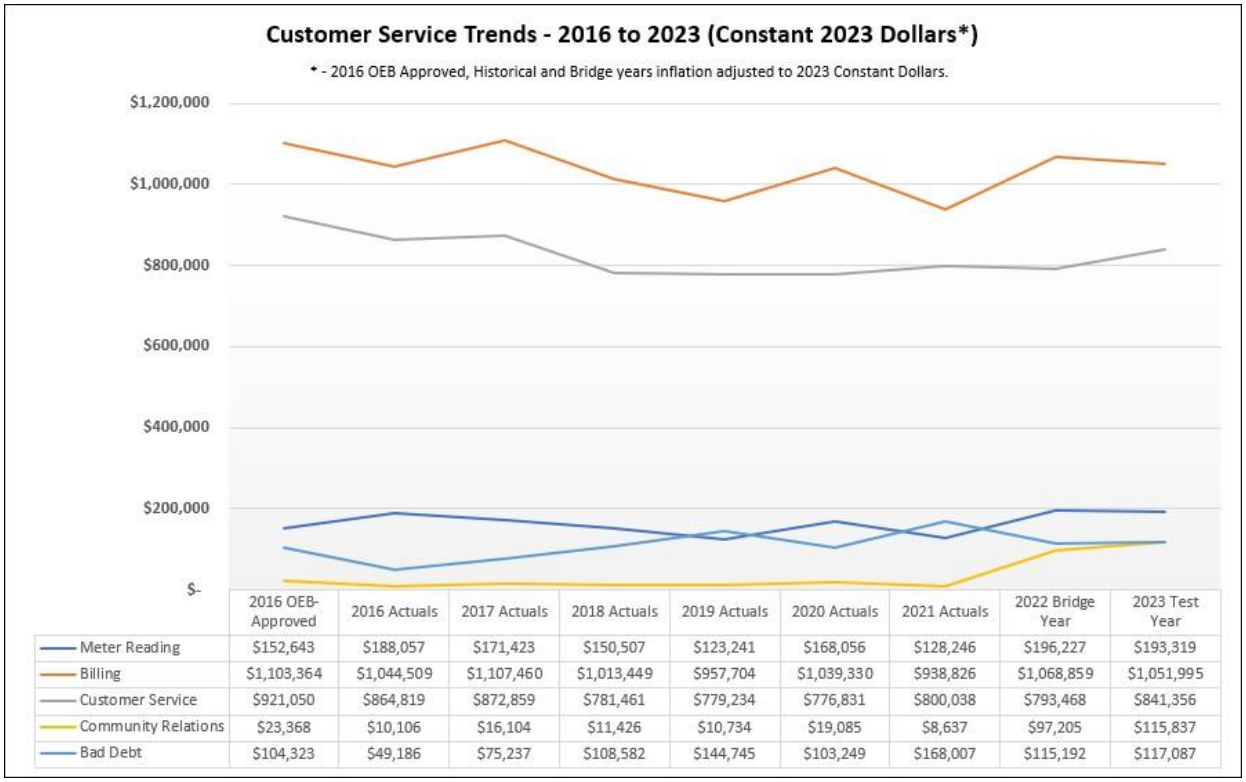
Chart 4.5. Customer Service Cost Trend



	2016 OEB-Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Meter Reading	$131,100	$161,517	$150,027	$133,303	$110,791	$154,100	$120,183	$189,958	$193,319
Billing	$947,646	$897,098	$969,237	$897,603	$860,954	$953,020	$879,801	$1,034,713	$1,051,995
Customer Service	$791,063	$742,767	$763,916	$692,133	$700,513	$712,320	$749,739	$768,121	$841,356
Community Relations	$20,071	$8,680	$14,094	$10,120	$9,650	$17,500	$8,094	$94,100	$115,837
Bad Debt	$89,600	$42,244	$65,846	$96,170	$130,122	$94,675	$157,444	$111,512	$117,087

Chart 4.6 presents the above trends on a "normalized" basis. Using the OEB approved inflation factor, annual expenditures are escalated in order to present information on a 2023 Test Year constant dollar basis.

Chart 4.6. Customer Service Cost Trend (Constant 2023 Dollars)



	2016 OEB-Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Meter Reading	$152,643	$188,057	$171,423	$150,507	$123,241	$168,056	$128,246	$196,227	$193,319
Billing	$1,103,364	$1,044,509	$1,107,460	$1,013,449	$957,704	$1,039,330	$938,826	$1,068,859	$1,051,995
Customer Service	$921,050	$864,819	$872,859	$781,461	$779,234	$776,831	$800,038	$793,468	$841,356
Community Relations	$23,368	$10,106	$16,104	$11,426	$10,734	$19,085	$8,637	$97,205	$115,837
Bad Debt	$104,323	$49,186	$75,237	$108,582	$144,745	$103,249	$168,007	$115,192	$117,087

On a 2023 Test Year constant dollar basis, the cost of the largest programs in this category (Billing and Customer Service) have declined over the 2016-2023 period. These programs represent over 80% of the expenditures in this category. There has been growth in other work program expenditures, with the largest being in the Community Relations program with an increase of $95,766 from the 2016 OEB approved level. This is due to the hiring of dedicated staff for this function and a focus on the customer and community as part of Milton Hydro's 2.0 Strategy.

4.3.4.1. Meter Reading

Key work activities in the Meter Reading program include importing verified MV90 data and billing quantity requests from the MDMR processed through Savage Data Systems, performing additional billing variance checks for usage exceptions using NorthStar billing software and responding to metering queries.

The Meter Reading program helps to ensure that bills are computed correctly, and customers are fairly charged for the services provided.

The Engineering Department is responsible for the installation of electricity meters. The Metering Department is responsible for testing, sampling and commissioning of existing and new, simple (e.g., residential smart meters) and complex (e.g. wholesale) metering installations. The Settlement Specialist and metering team is responsible for the operation and support of Milton Hydro's Automated Meter Infrastructure (AMI) smart meter system. Metering Reading includes the reverifications to meet regulatory requirements and ensure the accuracy of the installation for revenue billing requirements. Metering operations is also responsible for the investigation of any potential alteration and/or theft of power. The Settlement Specialist uses power fail signals from smart meters for more effective outage detection and ultimately faster outage response. Also included in this program are third party costs to electronically read smart meters and interval meters.

Table 4-21 provides the expenditures on Meter Reading from 2016 to 2023.

Table 4-21 Meter Reading

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Meter Reading	$131,100	$161,517	$150,027	$133,303	$110,791	$154,100	$120,183	$138,320	$189,958	$193,319

Meter reading expenditures are relatively stable over the 2016 - 2023 period, with the work volume increasing commensurate with customer growth and costs have increased consistent with the rate of inflation.

Planned 2023 Test Year expenditures are $193,319, and key initiatives include: direct labour charges from internal resources; third-party meter reading support for probing and disconnects and reconnects; and communication costs.

4.3.4.2. Customer Service

The Customer Service Program is responsible for the customer care activities of Milton Hydro's customers. These activities include call centre inquiries by phone and email, payment processing, move-in move-out requests, processing site orders, notification on outages for the overflow of the outage line, disconnects and reconnects and other office functions. Milton Hydro has experienced an increase in annual call volumes as a result of increased new customer connections, an increase in collection activity and an increase in move-in/move-out activity. The Customer Service staff are responsible for handling day-to-day inquiries and responding to numerous questions relating to regulatory policy, pricing, and consumption inquiries. The Customer Service group includes labour costs for the following positions: (6) Senior Customer Service Clerks, summer student(s), and a Customer Service Supervisor.

Milton Hydro offers customers a number of billing, paper bill, electronic bill, and payment options. These include on-line, pre-authorized payments, equal payment plan, credit card payments, mail in and drop box. Customers can view their usage and manage their consumption using an online application. Collection activity is not exclusive to overdue accounts; it also includes the adoption and continued application of the Customer Service Amendments consistent with the OEB’s DSC. The department is also responsible for the activation and reconciliation of the equal payment program and processing payments. Milton Hydro endeavors to maintain an early collections process to minimize the number of accounts near the disconnection stage. Active accounts are collected through phone calls, email reminder notices, hand delivered letters and follow up communication. Customer Service staff are responsible for handling day to day customer inquiries in regard to accounts and fielding numerous other questions as they relate to Government and Regulatory policy, conservation and demand management, pricing and consumption inquiries. In addition to this function, staff are also responsible for processing of all electronic payments, including payments dropped off at the office and post office mail payments, responding to emails, and numerous other administrative tasks.

The costs listed under customer care are primarily the costs related to the call centre. Call centre staff (Senior Customer Service Clerks and cashiering roles) assist customers with various inquiries related to bills, payments, new account set ups and other service requests, low-income customer programs and other initiatives.

The Customer Service group responsible for taking care of customer needs by providing professional and courteous service and assistance. Customer Service is the frontline in Milton Hydro’s pursuit of delivering outstanding service to the residents of Milton and value to the community. The advent of online businesses has set high customer service expectations. Milton Hydro strives to keep pace with these expectations while striking a balance between traditional high touch person to person customer care against the need to embrace information and customer interactive technology.

Collections Management includes Collections Support costs, Collections Charges and Field Collection Services. Collections Support costs account for approximately 62% of the collections management budget. These charges represent the costs associated with the early stages of Milton Hydro's Collections Process (i.e. friendly reminder notice (call/email), seven days later a collection/disconnection letter mailed, and prior to the 19 days allowed for disconnection, a follow up 48 hour call/e-mail looking for proof of payment. Milton Hydro does not have an automated dialer for reminder/payment request calls. As a result, Milton Hydro outsources this activity to a third party, Singlepoint, they also assist with the 48 hour follow up call and email. Historically, costs were fairly consistent year over year until 2017 at which time the Winter Disconnection Moratorium ("Moratorium") was introduced by the OEB which now prohibits LDCs from disconnecting residential customers for non-payment from November 15 to April 30. The Moratorium achieved the important outcome of protecting vulnerable customers from disconnection in the winter months, however it resulted in (i) an increase in the number of customers in collections at the end of the moratorium; and (ii) an increase in the overdue balances to be paid, as compared to years when the Moratorium was not in effect. This has resulted in an increase in Collections Support costs of 80% as compared to the 2016 Cost of Service application, as Milton Hydro's third-party provider was required to hire additional staff to support collections outside of the Winter Moratorium.

Table 4-22 provides the expenditures on Customer Service from 2016 to 2023.

Table 4-22 Customer Service

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Customer Service	$791,063	$742,767	$763,916	$692,133	$700,513	$712,320	$749,739	$726,898	$768,121	$841,356

Customer service expenditures are relatively stable over the 2016 - 2023 period, with cost increases primarily related to inflation, partially offset by a reduction of a Senior Clerk.

Planned 2023 Test Year expenditures are $841,356, and key initiatives include: salaries and benefits of the Call Centre staff; bad debt expense; costs associated with collections and credit management; and Milton Hydro's telephone and answering system.

4.3.4.3. Billing

Key work activities in the Billings/Finals/Collections program include issuing daily billing with integrity rate testing, meter changes and installations, invoice settlement, pre-authorized banking, and OEB rate change testing. This program includes the costs for bill print, postage and online billing, as well as the costs of billing staff.

Milton Hydro's billing staff are responsible for all billing activities supporting all customers in Milton Hydro's service territory. This includes monthly billing that results in Milton Hydro issuing over 513,000 bills annually in addition to approximately 10,200 final bills for customers moving within or outside of Milton Hydro's service territory. The billing department is responsible for:

a. Daily invoicing of electricity consumption and generation accounts, verifying set ups of rate class and meter positions, sending BQRs, verification of all data imported, various billing checks, rate change requests, RPP true up, balance Class A Global Adjustment, confirmation of WAP and retailer IBRs imported and daily rate integrity testing with OER, and postal mode update;

b. Testing all distribution and OEB rate changes, including the Ontario Electricity Rebate and any new rate options (e.g., tiered);

c. managing Electronic Business Transactions (EBT), sending NSLS and Retailer settlement functions for approximately 670 retailer enrolled accounts;

d. account adjustments; processing of meter changes (e.g. re-verification); and installations and billing corrections; CT and PT adjustments, net metering, adding cell modem and probing charges;

e. Sending preauthorized payment banking files;

f. Confirming eBills have been sent daily, and hard copies sent to ERTH Corporation for mailing;

g. Reclassification review; and

h. IESO reassignments.

Milton Hydro offers customers a number of billing and payment options including an electronic bill, pre-authorized payments, equal payment plan, and credit card payments. In addition, customers can view their usage and manage their consumption using the online *Silverblaze* application.

The Billing program is responsible for the accurate and timely billing of residential and commercial customers. This involves collecting, validating, and managing the accuracy of meter data and ensuring the integrity of the billing data received from the provincial Metering Data Management/Repository ("MDM/R"). The Billing program ensures compliance with regulatory requirements and implements changes relating to customer billing including rate changes, annual rate class reclassifications and the Industrial Conservation Initiative ("ICI"). The majority of the costs of the Billing program expenses are salaries & benefits and printing and postage costs associating with issuing customer invoices.

Postage, Mail Service and Stationery costs represent approximately 55% of the Billing program costs in the 2023 Test Year. Milton Hydro bills all Electricity customers monthly and by the end of 2023 expects to issue over 521,500, bills for its approximately 43,899 customers. Milton Hydro offers its customers electronic billing as a delivery option and has had several campaigns to encourage customers to sign up for paperless billing to reduce printing and postage costs. More than 70% of Milton Hydro's customers receive electronic bills which provide convenience and accessibility. The target is to have 75% of customers on e-billing by the end of 2023.

Table 4-23 provides the growth in e-billing since 2016.

Table 4-23 # of Customer on e-Billing

2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
11,556	13,799	17,490	18,919	28,925	29,850	30,149	30,450

Table 4-24 provides the expenditures on Billing from 2016 to 2023.

Table 4-24 Billing

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Billing	$947,646	$897,098	$969,237	$897,603	$860,954	$953,020	$879,801	$909,619	$1,034,713	$1,051,995

2023 Test Year expenditures are $142,376 higher than the average of 2016 to 2021 Actual, primarily due to: (i) cost increases of $107,261 associated with annual inflation; (ii) the 2021 mid-year procurement of billing services from ERTH; (iii) cost increases related to third-party support for remote Automatic Meter Reading ("AMR") services; partially offset by (iv) lower postage and delivery expenditures related to the increase in e-billing penetration. The outsourcing of bill print services provides capacity and the reduction of capital expenditures to replace an obsolete bill print machine. ERTH Corporation has demonstrated a proficiency in bill printing services which allows Milton Hydro staff to redirect employees to focus on more value-added work with additional cost avoidance opportunities.

2023 Test Year expenditures are $172,194 higher than 2021 Actual, primarily due to: (i) cost increases of $59,025 associated with annual inflation; (ii) cost increase of $59,000 for third-party support for remote AMR services; and (iii) the 2021 mid-year procurement of billing services from ERTH of approximately of $26,000. The outsourcing of bill print services present capacity and the reduction of capital expenditures to replace an obsolete bill print machine. ERTH Corporation has demonstrated a proficiency in bill printing services which allows Milton Hydro staff to redirect employees to focus on more value-added work with additional cost avoidance opportunities.

Planned 2023 Test Year expenditures are $1,051,995, and key initiatives include: postage and deliver charges; printing and office supplies; direct labour charges related to supervisory oversight and billing clerks; and Information Technology and support related to the Customer Information System.

4.3.4.4. Community Relations

Key work activities in the Community Relations program include various school education programs which rotate to various schools each year; customer outreach programs; “donate to the hospital” via an e-billing program; participation in the Milton Christmas parade; and, coordinating employee donations to the Salvation Army e.g., food and clothing. New in 2022 and 2023 are costs for “Branding” the New Milton 2.0 and Website maintenance.

Community Relations plays an important role by providing an opportunity to increase energy literacy, sharing information on new innovations, and communicating the role and value of Milton Hydro to customers. Milton Hydro is consistently recognized as a good corporate citizen through its involvement with many community organizations. The Company contributes to the community through various events and ongoing educational programs delivered to the public. Milton Hydro employees have built a strong tradition of generosity, giving both their time and money to support several local charities and charitable events. Employees at all levels, in all departments, enthusiastically participate in events throughout the year.

The Communications program is accountable for delivering timely, informed and quality communications to Milton Hydro's customers and stakeholders as it relates to Milton Hydro's operations. This includes: marketing programs, branding initiatives, digital content, social media, promotions, customer engagement activities, media relations and information with direct relevance to the interests of Milton Hydro's customers (i.e. outage communications, safety messaging). Milton Hydro undertakes communications planning on an annual basis to assist in anticipating communications issues and to formulate strategic and tactical approaches to address them. Milton Hydro strives to contribute to the quality of life in the community it serves, with a focus on corporate responsibility, Communications are delivered through information-rich channels that are easily accessible to customers. A primary function of the program is to provide enhanced customer engagement and communications, with the goal of helping customers make better choices and create healthy, sustainable results for themselves and the community Milton Hydro serves. This includes engaging with customers and stakeholders through community events and festivals, and community-based groups.

The Communications program functions include:

- Customer Direct communications (e.g., information bulletins, newsletters, inserts, surveys);
- Corporate communications (e.g., annual reporting, news releases, media relations, marketing, branding exercises); and
- Digital communications (e.g., Twitter, public website).

Milton Hydro engages customers directly through its customer satisfaction surveys which are a sounding board and provide important customer feedback. The surveys are a direct conduit between customers and Milton Hydro and help to prioritize communication initiatives and efforts important to customers. Similarly, results gleaned from the bi-annual Public Awareness of Electrical Safety Survey have helped Milton Hydro shape its communications priorities as it relates to educating the public about electrical safety.

Milton Hydro's public website (www.miltonhydro.com) is continually monitored and revised to ensure the latest news is being communicated and customer information needs are being met. A highly responsive site ensures emergency bulletins and updates can be readily posted on the homepage for easy access by customers, media, and stakeholders.

The Corporate Communications group is responsible for external and internal communications. This department develops communication plans and strategies to inform and educate customers on changes or new developments that may affect the services that they receive from Milton Hydro. Similarly, internal communications and programs are communicated to employees to ensure they have the most recent information regarding changes in the industry, safety issues and programs to provide a safe and healthy work environment.

This allows the Corporate Communications group to keep customers informed of changes to rules and regulations and made aware of tools and resources available to help them monitor and reduce their electricity usage. These new resources also help to increase internal communications that support Milton Hydro's corporate culture and keep employees connected and informed.

Table 4-25 provides the expenditures on Community Relations from 2016 to 2023.

Table 4-25 Community Relations

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Community Relations	$20,071	$8,680	$14,094	$10,120	$9,650	$17,500	$8,094	$11,356	$94,100	$115,837

Community relations expenditures are relatively stable over the 2016 - 2023 period, with consistent annual inflation and additional staff resources added to this program starting in 2022. Variances in this program do not exceed the materiality threshold for Milton Hydro.

Planned 2023 Test Year expenditures are $115,837, and key initiatives include: modest marketing programs, social media consulting work; branding initiatives; customer engagement activities including conservation programs; and website maintenance costs.

4.3.4.5. Bad Debt

The Bad Debt program is the provision amount for customer bills that are expected to be uncollectable in a given year. Milton Hydro attempts to minimize losses prior to account finalization through the application of Commercial deposits, modifying billing frequency, placement of outstanding receivables with third party collection agencies and pursuing legal action if applicable.

The Senior Customer Service Clerk(s) assigned to Collections, manages inactive (final billed accounts) and active accounts that have become past due. Staff are responsible for commencing collection activity when customer bills are past due. This proactive approach reduces the risk of non-payment and the associated bad debt expenditure for those customers who do pay their account. When a customer bill becomes past due, a reminder notice is sent to the customer. If no response, 7 days later, a collection/disconnect letter is mailed to the customer. Nineteen days, after the collection/disconnect letter has been issued, the service to the customer may be disconnected (outside the Disconnection Moratorium period). A follow up email/call is completed 48 hours prior to disconnection. When Milton Hydro has exhausted all efforts to collect overdue amounts from customers these amounts are written off as a "bad debt".

Table 4-26 provides the expenditures on Bad Debt from 2016 to 2023.

Table 4-26 Bad Debt

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Bad Debt	$89,600	$42,244	$65,846	$96,170	$130,122	$94,675	$157,444	$97,750	$111,512	$117,087

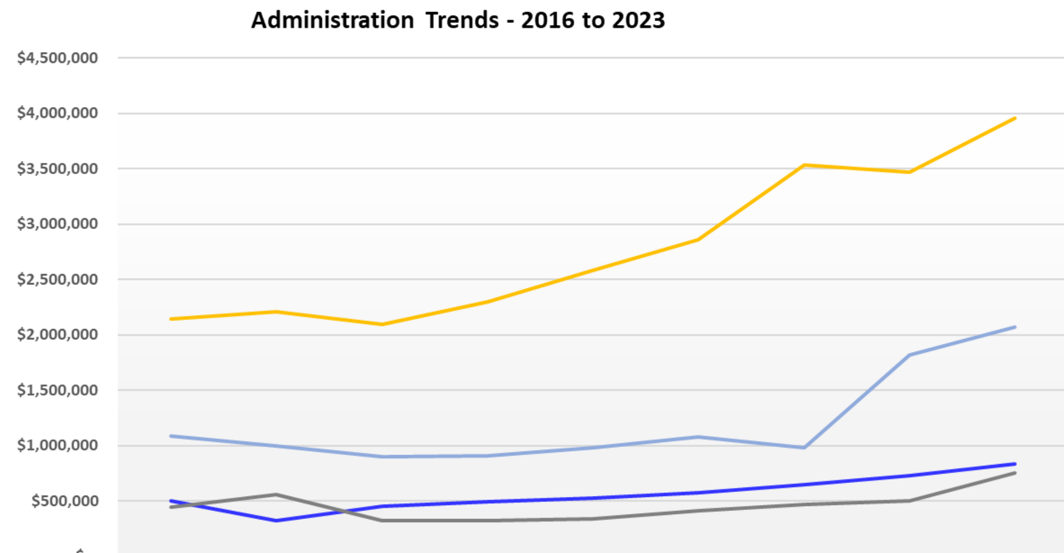
Bad debt expenditures are relatively stable over the 2016 - 2023 period, with the amount of bad debts consistent with the growth in the number of customers and increased Bad Debt experience due to economic circumstances.

Planned 2023 Test Year expenditures are $117,087, and key initiatives include: expected losses on past overdue accounts using historical trends experienced in prior years. These expected losses are netted against recoveries which are contracted out to third party collection agencies.

4.3.5. Administration Work Programs

The Administration category is comprised of General Administration, Software Maintenance, Regulatory and Executive and Board work programs. The following Chart 4.7 illustrates the overall expenditure trend from the 2016 OEB Approved level to the 2023 Test Year. Specific work programs are then discussed and variance explanations for material changes in the trend are provided.

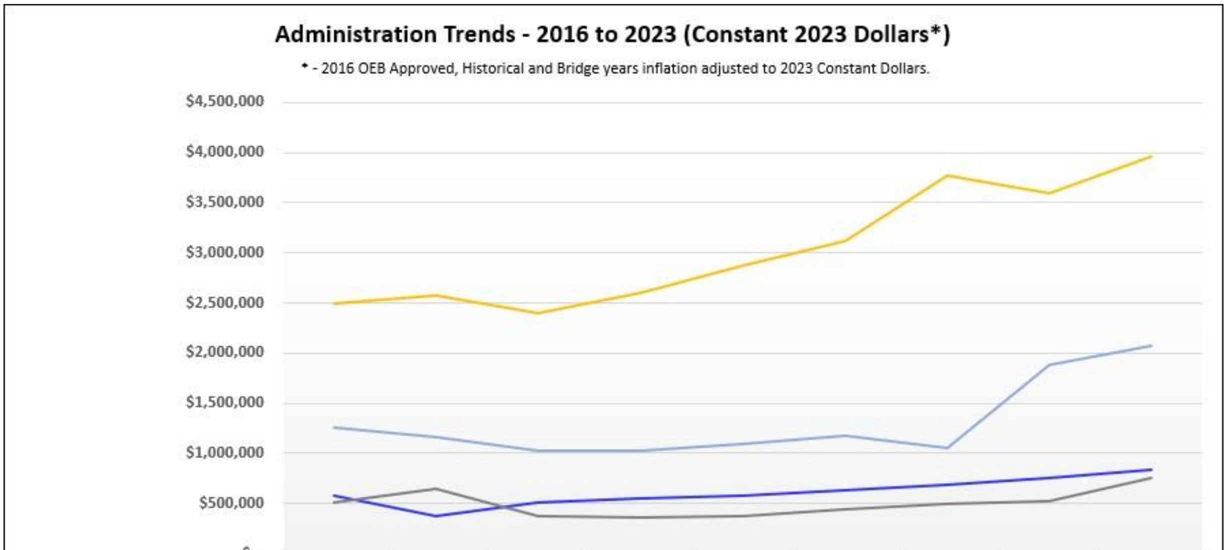
Chart 4.7. Administration Cost Trend



	2016 OEB-Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
General Administration	$2,143,949	$2,207,004	$2,093,305	$2,302,022	$2,582,337	$2,859,440	$3,533,049	$3,473,283	$3,958,082
Software Maintenance	$498,477	$324,397	$452,274	$491,752	$524,156	$575,582	$646,736	$729,966	$832,135
Regulatory	$444,060	$560,450	$326,658	$325,025	$339,094	$411,331	$469,548	$503,518	$750,664
Executive and Board Expenses	$1,083,873	$995,254	$896,219	$912,240	$983,228	$1,080,824	$982,433	$1,821,452	$2,074,802

Chart 4.8 presents the above trends on a "normalized" basis. Using the OEB approved inflation factor, annual expenditures are escalated in order to present information on a 2023 Test Year constant dollar basis.

Chart 4.8. Administration Cost Trend (Constant 2023 Dollars)



	2016 OEB-Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
General Administration	$2,496,243	$2,569,659	$2,391,832	$2,599,125	$2,872,530	$3,118,405	$3,770,078	$3,587,902	$3,958,082
Software Maintenance	$580,387	$377,702	$516,773	$555,218	$583,059	$627,709	$690,125	$754,055	$832,135
Regulatory	$517,028	$652,543	$373,243	$366,974	$377,200	$448,583	$501,049	$520,134	$750,664
Executive and Board Expenses	$1,261,975	$1,158,795	$1,024,029	$1,029,975	$1,093,719	$1,178,709	$1,048,343	$1,881,560	$2,074,802

Administration work programs have increased over the 2016 to 2023 period. Inflation is part of the reason for the increase, however, as can be seen in the 2023 constant dollar chart, even when costs are normalized, they are still increasing. The main reason for the increase is additional staffing costs in support of new initiatives, the migration of Milton Hydro to be better scaled as a large utility and the implementation of Milton Hydro's 2.0 Strategic vision. There was a steady increase in Administration expenditures from 2016 to 2021. This reflects Milton Hydro's commitment to the need for such expenditures despite being constrained in funding received through the annual IRM rate increases. The need for further program increases in 2022 and 2023 is discussed in this section on a work program basis and in Exhibit 4.4 Workforce Planning and Employee Compensation.

4.3.5.1. General Administration

Key work activities in the General Administration program include Building Maintenance, Corporate Finance, Human Resources, Information Technology, Management & Consulting and Office and Admin. Operations.

Table 4-27 provides a summary of the expenditures for each of these sub programs for the period 2016 OEB Approved to 2023 Test Year:

Table 4-27 General Administration Summary

General Administration	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Bridge Year	2023 Test Year
Building Maintenance	$420,479	$445,661	$460,718	$549,373	$525,107	$633,198	$617,660	$538,620	$858,552	$902,005
Corporate Finance	$695,100	$627,167	$549,708	$565,860	$481,399	$515,413	$660,870	$566,736	$827,726	$959,108
Human Resources	$198,633	$262,566	$253,232	$268,573	$462,864	$456,638	$626,357	$388,372	$311,714	$318,872
Information Technology	$156,218	$137,512	$142,064	$152,135	$156,797	$154,138	$159,244	$150,315	$305,958	$553,932
Management Consulting & Prof. Fees	$304,857	$305,643	$288,754	$364,376	$540,105	$572,212	$916,575	$497,944	$531,984	$600,043
Office and Admin Operations	$368,662	$428,455	$398,830	$401,705	$416,065	$527,842	$552,342	$454,207	$637,349	$624,122
TOTAL	**$2,143,949**	**$2,207,004**	**$2,093,306**	**$2,302,022**	**$2,582,337**	**$2,859,441**	**$3,533,048**	**$2,596,194**	**$3,473,283**	**$3,958,082**

4.3.5.1.1. Building Maintenance

Building and facilities expenditures are required for the repair maintenance and upkeep of Milton Hydro's administration building and operations/warehouse facility.

Expenses include utilities, cleaning services, landscaping and snowplowing, waste removal, fire monitoring, security monitoring, building supplies, pest control and general building maintenance. The building is primarily heated via a Geothermal HVAC system with an Energy Recovery Vessel (ERV) mounted on the roof. While the system is more energy efficient than a conventional HVAC system is requires more frequent preventative maintenance to ensure functionality and life cycle optimization.

Table 4-28 Building Maintenance

	Historical Year								Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Building Maintenance	$420,479	$445,661	$460,718	$549,373	$525,107	$633,198	$617,660	$538,619	$858,552	$902,005

2023 Test Year expenditures are $481,526 higher than 2016 OEB Approved, primarily due to: (i) higher labour costs of $321,096, which include the addition of a Manager, Supply Chain Management to support overall oversight and monitoring of Facilities, services and operations; and the addition of a Procurement Specialist to provide services and the co-ordination of inventory and stock; (ii) an $80,423 increase in property taxes resulting from increased property value assessments; and (iii) cost increases of $69,093 associated with annual inflation.

2023 Test Year expenditures are $363,386 higher than the average of 2016 to 2021 Actual, primarily due to: (i) the addition of a Manager, Supply Chain Management to support overall oversight and monitoring of Facilities, services, and operations; and the addition of a Procurement Specialist to provide services and the co-ordination of inventory and stock; and (ii) cost increases associated with annual inflation.

2023 Test Year expenditures are $284,345 higher than 2021 Actual, primarily due to: (i) $237,800 related to the addition of a Manager, Supply Chain Management to support overall oversight and monitoring of Facilities, services, and operations; and the addition of a Procurement Specialist to provide services and the co-ordination of inventory and stock: and (ii) cost increases of $41,438 associated with annual inflation.

In Milton Hydro's last COS proceeding, EB-2015-0089 2016 Decision and Order, the OEB denied $50,000 of Building Maintenance costs in the test year and Milton Hydro reduced its OM&A budget for rate setting purposes accordingly. Milton Hydro's actual incurred building maintenance costs from 2016 to 2021 do not reflect a reduction to OM&A for this disallowance. The 2022 Bridge Year and 2023 Test Year do not reflect a disallowance either since Milton Hydro has presented justification to incorporate the full building cost in the 2023 Rate Base. See Exhibit 2 sub-section 2.2.2. Bringing Disallowed Space into Rate Base.

Planned 2023 Test Year expenditures are $902,005, and key initiatives include: direct labour to support property maintenance, property taxes, and third-party support for repairs and building maintenance.

4.3.5.1.2. Corporate Finance

The program includes managing and monitoring the financial aspects of Milton Hydro’s business operations. This work includes:

a. general accounting and financial compliance;

b. reporting and policy development;

c. preparing statutory, management and financial reports/statements;

d. general accounting and accounts payable;

e. treasury functions, including borrowing and cash management;

f. financial risk management;

g. accounting systems and internal control processes;

h. preparing consolidated operating and capital budgets and forecasts; and

i. tax compliance.

Costs increase in 2023 partially due to the hiring of a Client Services Financial Analyst. See Exhibit 4, Section 4.4.3.3 for further information on this position.

Table 4-29 Corporate Finance

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Corporate Finance	$695,100	$627,167	$549,708	$565,860	$481,399	$515,413	$660,870	$566,736	$827,726	$959,108

2023 Test Year expenditures $264,008 higher than 2016 OEB Approved, primarily due to: (i) $258,358 for the addition of a dedicated Payroll Specialist to mitigate critical single incumbent risk; and the addition of a Client Services Financial Analyst to support the organization customer centric approach to providing analysis and support to the organization; (ii) cost increases of $114,219 associated with annual inflation; partially offset by (iii) $112,645 related to the elimination of the CDM Specialist role resulting from the elimination of the Conservation First Framework program.

2023 Test Year expenditures are $392,372 higher than the average 2016 to 2021 Actual, primarily due to: (i) the addition of a dedicated Payroll Specialist to mitigate critical single incumbent risk; and the addition of a Client Services Financial Analyst to support the organization customer centric approach to providing analysis and support to the organization; (ii) cost increases associated with annual inflation; partially offset by (iii) elimination of the CDM Specialist role resulting from the elimination of the Conservation First Framework program.

2023 Test Year expenditures are $298,238 higher than 2021 Actual, primarily due to: (i) the addition of a Client Services Financial Analyst to support the organization customer centric approach to providing analysis and support to the organization; (ii) cost increases associated with annual inflation; and (iii) other financial support cost increases.

Planned 2023 Test Year expenditures are $959,108, and key initiatives includes direct labour to support the financial functions of business operations.

4.3.5.1.3. Human Resources

Human Resources involves all aspects of employee lifecycle management (recruitment, orientation and onboarding, performance management, training, development, through to retirement processing), labour relations, payroll and benefit administration, attendance and disability/WSIB management, employee culture and engagement, policy development, legislative compliance, reporting and strategic resource and succession planning.

The Human Resources program is responsible for effective management of all employee and labour relations, including the interpretation and administration of the collective agreement provisions, non-occupational and occupational illness or employee injury claims, case management, talent acquisition, training and development, payroll administration, design and administration of the compensation and benefits program, and associated technology systems and solutions. The Human Resources program supports both unionized and non-unionized work groups to ensure workplace issues are addressed promptly and appropriately, and in compliance with legislation, policies, and collective agreement procedures. The program develops and executes the strategic workforce staffing plan, organization and job design, succession planning, employee communication, performance and productivity, and employee development strategies and programs. The payroll function ensures that Milton Hydro employees are compensated for their services in a timely and accurate manner, consistent with relevant time-keeping and other records. The function also ensures that all relevant legislative requirements and statutory deductions are appropriately applied to employee payments and that payroll withholding amounts are remitted on a timely basis. In addition, the function maintains accurate OMERS pension fund records for participating employees.

Costs in 2023 include the Manager, People and Culture and a Manager Health and Safety. See Exhibit 4, Section 4.4.3.3 for further information on these positions.

Table 4-30 Human Resources

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Human Resources	$198,633	$262,566	$253,232	$268,573	$462,864	$456,638	$626,357	$388,372	$311,714	$318,872

2023 Test Year expenditures are $307,485 lower than 2021 Actual, primarily due to: (i) incentives in the 2023 Test Year being reported within each functional area and operating program which is a change in methodology from 2021 (and prior years) incentive costs were recorded centrally in the Human Resources program; partially offset by (ii) the addition of the Manager, Health and Safety in 2022. Prior to this, Milton Hydro did not have a dedicated Health and Safety staff position as services were provided by a contracted third party.

Planned 2023 Test Year expenditures are $318,872, and key initiatives includes direct labour to support people and safety.

4.3.5.1.4. Information Technology

The Information Technology Program is responsible for all aspects of Milton Hydro's information technology investment, support, and services in alignment with Milton Hydro's strategic business plans and budget requirements. These responsibilities include the following:

a. Infrastructure support of all Milton Hydro assets including telecommunications, telephony, hardware, software and network administration;

b. Coordination with key service providers for Milton Hydro's program of externally managed services and cloud technology;

c. Implementation and management of Milton Hydro's Information Security Management System in alignment with the Ontario Cyber Security Framework;

d. Business Application Implementation and Support;

e. Disaster Recovery and Backup Recovery; and

f. Maintaining license compliance with all hardware and software technology.

The risk of security breaches and exposure to cyber-attacks within the electrical energy sector has grown substantially with the implementation of Smart Grids, Smart Metering and Self-Generation. Increased use of automation, different communication networks, and the use of wireless networks, data flows, handheld electronic devices and the internet have created new IT related risks. As well, the growing demand for real-time data exchange between entities within the province, to support business units has resulted in increased cyber security risks. In December 2017, the OEB issued its Ontario Cyber Security Framework with the objective to increase security and privacy in LDC’s, with the overall goal of reducing cyber risk and improving service resilience. Furthermore, in 2018 the OEB issued a Notice of Amendments to the Distribution System Code, which established regulatory requirements for licensed distributors to provide the OEB with information on the actions they are taking relative to their cyber security risks. Over the past five years, there have been significant changes and advancements in Information Technology (IT) and Cybersecurity. Milton Hydro has become more aware of cyber threats and has continued to augment precautions to protect customer’s personal information and data.

Costs increase in 2023 partially due to the hiring of a Director, Information Technology & Client Services. See Exhibit 4, Section 4.4.3.3 for further information on this position.

Table 4-31 Information Technology

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Information Technology	$156,218	$137,512	$142,064	$152,135	$156,797	$154,138	$159,244	$150,315	$305,958	$553,932

2023 Test Year expenditures are $397,714 higher than 2016 OEB Approved, primarily due to: (i) labour costs of $345,337 related to the addition of the Director, IT & Client Services to provide strategic expertise and oversight into executing Milton Hydro's IT strategy (Optimizing Performance & Delivery); and the addition of an IT Security & Infrastructure Specialist to primarily focus on the security and ongoing protection of Milton Hydro's assets and data; and (ii) cost increases of $25,670 associated with annual inflation.

2023 Test Year expenditures are $403,617 higher than the average of 2016 to 2021 Actual, primarily due to: (i) the addition of the Director, IT & Client Services to provide strategic expertise and oversight into executing Milton's IT strategy (Optimizing Performance & Delivery); (ii) the addition of an IT Security & Infrastructure Specialist to primarily focus on the security and ongoing protection of Milton Hydro's assets and data; and (iii) cost increases associated with annual inflation.

2023 Test Year expenditures are $394,688 higher than 2021 Actual, primarily due to: (i) the addition of the Director, IT & Client Services to provide strategic expertise and oversight into executing Milton's IT strategy (Optimizing Performance & Delivery); and (ii) the addition of an IT

Security & Infrastructure Specialist to primarily focus on the security and ongoing protection of Milton Hydro's assets and data.

2023 Test Year expenditures are $247,974 higher than 2022 Bridge Year, primarily due to the addition of the Director, IT & Client Services to provide strategic expertise and oversight into executing Milton's IT strategy (Optimizing Performance & Delivery); and (ii) the addition of an IT Security & Infrastructure Specialist to primarily focus on the security and ongoing protection of Milton Hydro's assets and data.

Planned 2023 Test Year expenditures are $553,932, and key initiatives includes direct labour to support operations and system maintenance.

4.3.5.1.5. Management Consulting and Professional Fees

The program includes costs such as professional management fees from Milton Hydro Holdings, external financial audit, income tax filing preparation, outside consultants e.g.: Labour Relations Strategy Consultants, Cyber Security Consultants, Strategic Consultants, and legal costs incurred as part of the utility’s business operations.

Table 4-32 Management Consulting and Professional Fees

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Management Consulting & Prof. Fees	$304,857	$305,643	$288,754	$364,376	$540,105	$572,212	$916,575	$497,944	$531,984	$600,043

2023 Test Year expenditures are $295,186 higher than 2016 OEB Approved, primarily due to: (i) $125,000 for the development of an IT roadmap to ensure a strategic and structured approach to identify the technology investments and implementation activities required by Milton Hydro over the 2023 to 2027 rebasing period; (ii) $82,000 for third-party support for Milton Hydro’s strategies and approach to managing its resources and ensuring operational capability and capacity to efficiently; and (iii) $50,094 related to general inflation.

2023 Test Year expenditures are $316,532 lower than 2021 Actual, primarily due to: (i) $125,000 related to lower expenditures from completion of the IT roadmap prepared in 2021; (ii) cost increases of $140,000 to manage Health and Safety initiatives; and (iii) $82,000 lower due to completion of third-party support for strategic initiatives. The cost increases for Health and

Safety is offset with increases in Human Resources for the hiring of a permanent Manager, Health and Safety.

Planned 2023 Test Year expenditures are $600,043, and key initiatives includes: third-party support costs to support strategic initiatives; audit fees to support statutory financial requirements; and director stipends and meeting fees.

4.3.5.1.6. Office and Administration

This program includes the monthly costs of phone service, fibre services, postage, bill print paper, bank charges, etc. This program includes costs for executive insurance, liability insurance and property insurance required to protect Milton Hydro in its daily operations. LEAP is also part of this work program. Funding for LEAP is calculated at 0.12% of the Service Revenue Requirement and the amount of $32,500 is provided to local service agencies to help low-income customers pay their electricity bills.

Table 4-33 Office and Administration

	Historical Year								Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Office and Admin Operations	$368,662	$428,455	$398,830	$401,705	$416,065	$527,842	$552,342	$454,207	$637,349	$624,122
Office and Admin Operations - Inflation Adjusted	$429,241	$498,859	$455,707	$453,550	$462,821	$575,646	$589,398	$505,997	$658,382	$624,122

Variances	$ Historical	2023	Inflation Effect
2023 Test Year vs 2016 OEB Approved	$255,460	$194,881	$60,579
2023 Test Year vs 2016 to 2021 Average Actual	$169,915	$118,125	$51,790
2023 Test Year vs 2021 Actual	$71,780	$34,724	$37,056
2023 Test Year vs 2022 Bridge Year	($13,227)	($34,260)	$21,033

2023 Test Year expenditures are $255,460 higher than 2016 OEB Approved, primarily due to: (i) cost increases of $60,579 associated with annual inflation; (ii) annual bond rating expenditures of $60,000; (iii) an increase in corporate and professional subscription and membership dues of $34,000; (iv) $34,000 in professional and leadership development training programs not budgeted in 2016 OEB approved; (v) $32,500 higher Low-Income Energy Assistance Program ("LEAP") expenditures previously not included in the 2016 OEB Approved; (vi) increase in general liability, crime, cyber, property and fleet insurance expenditures of $28,000; and (vii) increase in phone and mobile expenditures of $21,000.

2023 Test Year expenditures are $169,915 higher than the average of 2016 to 2021 Actual, primarily due to: (i) annual bond rating expenditures; (ii) increase in corporate and professional subscription and membership dues; (iii) professional and leadership development training programs not budgeted in 2016 OEB approved; (iv) higher Low-Income Energy Assistance Program ("LEAP") expenditures previously not included in the 2016 OEB Approved; (v) increase in general liability, crime, cyber, property and fleet insurance expenditures; (vi) increase in phone and mobile expenditures; and (vii) cost increases associated with annual inflation.

Planned 2023 Test Year expenditures are $624,122, and key initiatives include: Low-income Energy Assistance Plan ("LEAP") donations; comprehensive liability insurance; bank charges and fees; telephone and mobile expenditures; Corporate memberships and subscriptions; professional fees for employee accreditation; corporate training and development; and general office supplies to support day-to-day operations.

4.3.5.2. Software Maintenance

Software maintenance costs largely pertain to support and maintenance costs of the CIS and AMI systems. The CIS system is a key enabler of customer service and billing capabilities. It facilitates the collection and storage of customer account information and supports the delivery of customer care, meter data management, customer invoice generation, and collection of revenues. The AMI system is a key enabler of metering and billing capabilities. It facilitates the collection and storage of meter data and supports the delivery of meter data management, billing determinants, and outage detection.

Milton Hydro’s cyber security program has been continuously evolving as threats and complexities increase due to: increased reliance on the internet, greater number of web and mobile applications, employees accessing data from the field, cloud adoption, increases in Internet of Things (“IoT”) devices and decentralized energy resources. The distribution system’s interdependencies between physical and cyber infrastructure make it particularly vulnerable to exploitation, including billing fraud (via smart meters and wireless technology) and even potential equipment damage caused by the commandeering of digitally controlled physical assets.

The Software Annual Maintenance program includes all business systems, all operation related software for servers and devices, backup software solutions, and cloud-based systems. The maintenance costs associated with Milton Hydro's business systems continue to increase as the utility grows and moves towards more cloud-based systems.

Table 4-34 provides the expenditures on Software Maintenance from 2016 to 2023.

Table 4-34 Software Maintenance

Description	2016 OEB Approved	Historical Year 2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	Bridge Year 2022 Forecast	Test Year 2023 Forecast
Software Maintenance	$498,477	$324,397	$452,274	$491,752	$524,156	$575,582	$646,736	$502,483	$729,966	$832,135

2023 Test Year expenditures are $333,658 higher than 2016 OEB Approved, primarily due to: (i) cost increases of $81,910 associated with annual inflation; (ii) $54,000 for annual software maintenance expenditures to support technology investments during the rebasing period (omni-channel platform, process automation tools, HRIS and payroll systems); (iii) $50,000 for the acquisition of a cloud based compliance reporting and management solution to deliver statutory, management and regulatory more productively; (iv) $38,000 for higher software maintenance costs on the Customer Information System ("CIS"); (v) $37,000 for increased software maintenance costs related to the legacy Financial Management System; (vi) $34,000 for higher license costs for Engineering systems and maintenance; (vii) increases in licenses related to office products and cyber corresponding to increased headcount and rates; (viii) $32,000 for increased in server support application expenditures; and (ix) $30,000 for services supporting network and communication technology for delivering Advanced Metering Infrastructure ("AMI").

2023 Test Year expenditures are $329,652 higher than the average of 2016 to 2021 Actual, primarily due to: (i) increases in software maintenance costs related to the legacy Financial Management System; (ii) general inflation on expenditures; (iii) annual software maintenance expenditures to support technology investments during the rebasing period (omni-channel platform, process automation tools, HRIS and payroll systems); (iv) the acquisition of a cloud based compliance reporting and management solution to deliver statutory, management and regulatory more productively; (v) higher software maintenance costs on the Customer Information System ("CIS"); (vi) higher license costs for Engineering systems and maintenance; (vii) increases in licenses related to office products and cyber corresponding to increased headcount and rates; (viii) increase in server support application expenditures; and (ix) higher expenditures for services supporting network and communication technology for delivering Advanced Metering Infrastructure ("AMI").

2023 Test Year expenditures are $185,399 higher than 2021 Actual, primarily due to: (i) $52,000 for process automation tools; (ii) $50,000 for the acquisition of a cloud based compliance reporting and management solution to deliver statutory, management and regulatory more productively; (iii) cost increases of $43,389 associated with annual inflation; (iv) cost increases of $16,000 to support payroll and Human Resource Information System ("HRIS:); and (v) cost increases of $14,000 for cyber security software to protect assets from external threats.

Planned 2023 Test Year expenditures are $832,135, and key initiatives include the external costs to maintain and administer software capital.

4.3.5.3. Regulatory

Starting In 2021, activities of the Regulatory work program were expanded beyond what the program consisted of in Milton Hydro's 2016 rebasing rate application. Key activities of the program include compliance with OEB rules/codes, industry regulations, and wholesale settlements with the Independent Electricity System Operator (IESO), host distributors and embedded generators.

The Regulatory Affairs Department has staff consisting of a Director, Regulatory Affairs, and a Regulatory Specialist. A business case for the Regulatory Specialist was made, approved, and implemented in 2021. Details of the business case can be found in Exhibit 4, Section 4.4.3.3. The Regulatory program is accountable for all aspects of regulatory processes for Milton Hydro including regulatory filings; compliance with applicable codes and legislation; regulatory accounting; wholesale settlements; related internal operational support; and external customer facing support. The Regulatory Affairs group builds and supports key relationships with the regulator, industry peers, and stakeholders to monitor, influence, and evaluate potential impacts and opportunities related to industry regulation and government energy policy. A primary function of Regulatory Affairs is developing and defending applications for electricity distribution rates (i.e. Cost of Service Applications and annual Incentive Rate Mechanism ("IRM") applications). Regulatory Affairs advises executive management of the financial, operational and customer implications of current and evolving regulation with respect to corporate strategy and compliance.

The Regulatory program is responsible for overseeing regulatory compliance with the various energy related legislative requirements and applicable codes to which Milton Hydro must adhere. This group also serves as a liaison with other functional areas, ensuring that all OEB regulations and information are provided to the relevant groups and departments within Milton Hydro and confirming implementation of any changes to OEB rules and Regulations.

Key activities include:

a. Customer Service support:

   i. Customer reclassifications

   ii. Rate change bill testing

   iii. Customer RPP self-certification forms, and involved with back-billing credits to customers as required

b. Regulatory Accounting:

   i. Revenue and Cost of Power ("COP") budgeting, forecasting, reporting and variance analysis

   ii. Wholesale power cost accruals

   iii. Compliance with Accounting Procedures Handbook

   iv. Reconciliation and analysis of regulatory deferral and variance accounts

c. Wholesale Settlements:

   i. Gross Load Billing submission

   ii. IESO settlement filing submissions including RPP Settlements

   iii. Compliance with IESO requirements of Industrial Conservation Initiative (ICI) including Class A customer analysis, communication, and submission.

d. Complex customer queries and support on industry matters

e. Development and preparation of evidence for rate filings including support of the Distribution System Plan

f. OEB Reporting and Record Keeping Requirements (“RRRs”)

g. Statistics Canada and other related filings and reporting

h. Implementation of new industry regulations

i. Monitoring proposed changes in the industry

j. Maintenance and updating of reports for submissions as required

k. Stakeholder participation in energy-related policy proceedings

l. Cooperation with energy-related regulatory audits, inspections, and examinations

m. Handling all MOE, MOF, OEB, and IESO compliance-related matters

The Regulatory program also includes the annual OEB Cost Assessment, OEB Cost Awards for OEB initiated proceedings, costs of biennial Customer Safety Awareness and Customer Satisfaction Surveys, and costs related to the cost-of-service application. The cost of preparing the cost of service application, is allocated over the 5-year term of the cost of service/IRM period. Other internal labour costs for the cost of service application are included in the Executive, General Administration and Engineering work programs.

Table 4-35 provides the expenditures on Regulatory from 2016 to 2023.

Table 4-35 Regulatory

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Regulatory	$444,060	$560,450	$326,658	$325,025	$339,094	$411,331	$469,548	$405,351	$503,518	$750,664

2023 Test Year expenditures are $306,604 higher than 2016 OEB Approved, primarily due to: (i) $129,000 for the addition of a dedicated Regulatory Specialist; (ii) $65,000 for increased annual OEB assessment fees; and (iii) $72,968 related to general inflation.

2023 Test Year expenditures are $345,313 higher than the average 2016 to 2021 Actual, primarily due to: (i) the addition of a dedicated Regulatory Specialist; (ii) an increase in annual OEB assessment fees; and (iii) general inflation on labour and non labour expenditures.

2023 Test Year expenditures are $281,116 higher than 2021 Actual, primarily due to: (i) $153,000 related to the amortization of deferred 2023 rate application preparation costs; (ii)

$65,000 for higher OEB annual assessment fees; (iii) cost increases of $31,501 associated with annual inflation; and (v) $27,000 for the addition of a dedicated Regulatory Specialist.

2023 Test Year expenditures are $247,146 higher than 2022 Bridge Year, primarily due: (i) $153,000 for the amortization of deferred 2023 rate application preparation costs; and (ii) a $65,000 increase in OEB annual assessment fees.

Planned 2023 Test Year expenditures are $750,664, and key initiatives include: salaries and benefits; amortization of deferred 2023 rate application preparation costs; and OEB annual assessment and fees.

4.3.5.4. Executive and Board

The Executive and Board program is responsible for corporate governance and leadership, as well as the development and execution of the Company's Strategic Plan. This group consists of the Executive Team, the CEO's Executive Assistant and an Executive Assistant to the Board who performs activities associated with Milton Hydro's Board of Directors. Responsibilities include reviewing and approving all matters before submission to the Board related to legal issues, enterprise risk management, financial affairs, policies, new initiatives, customer service, safety, reliability, capital investments, operating procedures, regulatory requirements and filings and human resource matters. All matters are reviewed within the context of Milton Hydro's Purpose, Vision and Values.

The Executive and Board program is responsible for the overall governance and leadership of the organization and ensures that an appropriately skilled and experienced Milton Hydro Board and executive management team are in place. In addition to the salaries and benefits of executive management and Milton Hydro Board remuneration, other expenses incurred by Milton Hydro to deliver the governance and leadership necessary for adherence to strong business practices include legal, strategic consulting, industry association dues and risk management (insurance) services. This program also includes the annual incentive compensation expense for all non-union personnel.

Director Remuneration includes the annual and per meeting stipends of Milton Hydro's Board of Directors.

Costs increase in 2023 partially due to the hiring of executive positions consistent with Milton Hydro's 2.0 Strategy. These positions are required to provide leadership to meet the objectives of being a future ready company, being customer centric, developing organizational capability and positioning the Company for growth. The new positions are:

- Vice-President, Customer Experience;
- Vice-President, Corporate Services; and
- Process Improvement Officer

The rationale for these positions and the associated scope of work is discussed in Exhibit 4, Sub-section 4.4.3.3.

Table 4-36 provides the expenditures on Executive and Board from 2016 to 2023. Also provided in the table are year over year changes in program expenditures as well as a comparison of the 2023 Test Year to 2016 Board Approved and 2021 Actual expenditures.

Table 4-36 Executive and Board Expenses

		Historical Year							Bridge Year	Test Year
Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	6 Year Average	2022 Forecast	2023 Forecast
Executive and Board Expenses	$1,083,873	$995,254	$896,219	$912,240	$983,228	$1,080,824	$982,433	$975,033	$1,821,452	$2,074,802

2023 Test Year expenditures are $990,929 higher than 2016 OEB Approved, primarily due to: (i) $579,000 for the addition of the Vice President of Customer Experience, Vice President of Corporate Services, and Process Improvement Officer positions; (ii) $356,000 for the allocation of incentives previously reported within the Human Resources program; (iii) cost increases of $178,102 associated with annual inflation; partially offset by (iv) $170,000 related to the elimination of Director, Engineering position.

2023 Test Year expenditures are $1,099,769 higher than the average of 2016 to 2021 Actual, primarily due to: (i) the addition of the Vice President of Customer Experience, Vice President of Corporate Services, and Process Improvement Officer; (ii) general inflation on expenditures, salaries and benefits; and (iii) the allocation of incentives previously reported within the Human Resources program.

2023 Test Year expenditures are $1,092,369 higher than 2021 Actual, primarily due to: (i) $565,000 for the addition of the Vice President of Customer Experience, Vice President of Corporate Services, and Process Improvement Officer; (ii) $356,000 for incentives previously reported within the Human Resources program; and (iii) cost increases of $65,910 associated with annual inflation.

2023 Test Year expenditures are $253,350 higher than the 2022 Bridge Year, primarily due to: (i) $217,000 relating to the full year impact of the addition of the Vice President of Customer Experience and Vice President of Corporate Services - hiring occurred at various times in 2022; (ii) cost increases of $60,108 associated with annual inflation; partially offset by (iii).

Planned 2023 Test Year expenditures are $2,074,802, and key initiatives include: salaries and benefits; board stipends and meeting fees; and modest administration costs to support training and development.

4.3.5.5. Regulatory Costs

Table 4-37 (OEB Appendix 2-M) summarizes Milton Hydro's ongoing and one-time regulatory costs. It is noted that this summary does not include internal labour costs associated with staff involved in preparing regulatory submissions in support of this application or other regulatory requirements. Such costs are included in other work programs, primarily General Administration, Executive and Engineering Administration. One-time costs associated with this Cost of Service application include consultant costs for studies and reports (e.g. Customer Engagement, Customer Growth, LRAM-VA), preparation and support for other content in the rate application (e.g. Distribution System Plan, Load Forecast, Rate Design, Workforce Planning), Legal Fees and Intervenor cost awards.

Table 4-37 Appendix 2-M Regulatory Costs

	Regulatory Cost Category	USoA Account	USoA Account Balance	Last Rebasing Year (2016 OEB Approved)	Last Rebasing Year (2016 Actual)	Most Current Actuals Year 2021	2022 Bridge Year	Annual % Change	2023 Test Year	Annual % Change
	(A)	(B)	(B)	(D)	(E)	(F)	(G)	(H)=[(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
	Regulatory Costs (Ongoing)									
1	OEB Annual Assessment	5655		$ 93,000	$ 93,000	$ 93,000	$ 93,000	0.00%	$ 158,000	69.9 %
2	OEB Section 30 Costs (OEB-initiated)	5655		$ 2,500	$ 6,043	$ 10,068	$ 8,000	-20.54%	$ 6,000	(25.0)%
3	Expert Witness costs for regulatory matters									
4	Legal costs for regulatory matters					$ 14,962	$ 5,000	-66.58%	$ 5,000	— %
5	Consultants' costs for regulatory matters			$ 27,300	$ 17,039	$ 34,382	$ 13,927	-59.49%	$ 36,000	158.5 %
6	Operating expenses associated with staff resources allocated to regulatory matters									
7	Operating expenses associated with other resources allocated to regulatory matters 1	5655		$ 3,100						
8	Other regulatory agency fees or assessments									
9	Any other costs for regulatory matters (please define)	5655								
10	Intervenor costs									
11	OEB Licence Fee				$ 800	$ 800	$ 1,500	87.50%	$ 1,500	— %
29										
30										
	Regulatory Costs (One-Time)									
1	Expert Witness costs									
2	Legal costs	5655		$ 40,440	$ 43,364				$ 100,000	
3	Consultants' costs	5655		$ 34,720	$ 99,649				$ 373,919	
4	Incremental operating expenses associated with staff resources allocated to this application.								110,338	
5	Incremental operating expenses associated with other resources allocated to this application. 1								2,159	
6	Intervenor costs	5655		$ 48,000	$ 99,705				$ 180,000	
7	OEB Section 30 Costs (application-related)									
8	Include other items in green cells, as applicable									
9										
1	Sub-total - Ongoing Costs 2		$ —	$ 125,900	$ 116,882	$ 153,212	$ 121,427	-20.75%	$ 206,500	70.06 %
2	Sub-total - One-time Costs 3		$ —	$ 123,160	$ 242,718	$ —	$ —		$ 766,416	
3	Total		$ —	$ 249,060	$ 359,600	$ 153,212	$ 121,427	-20.75%	$ 359,783	196.30 %

4.3.5.6. One-time Costs

Milton Hydro incurred One-Time costs in the preparation of the 2023 Cost of Service application and is proposing that these costs be recovered equally in the Test Year and the subsequent IRM term. This will result in $153,283 or 1/5th of the total amount of $766,415 being recovered in each of the years 2023 to 2027.

Table 4-38 provides a summary of one-time costs incurred to prepare the 2023 Cost of Service application:

Table 4-38 One-Time Costs

Description	2021 Actual	2022 Bridge Year	2023 Test Year	Total
One Time Costs Incurred	$218,142	$368,273	$180,000	$766,415
Amortized (1/5th per/yr. 2023-2027				$153,283

4.3.5.7. Low-Income Energy Assistance Programs (LEAP)

Milton Hydro follows the OEB Accounting Procedures Handbook ("APH") with respect to charitable donations. In accordance with the APH, any general donations are to be tracked in USoA Account 6205 and these are not included in the revenue requirement for the Test Year. As per section 2.4.3.7 of the Chapter 2 Filing Requirements, only donations specifically for the Low-Income Energy Assistance Program ("LEAP") are to be included in the revenue requirement for the 2023 Test Year. These are tracked in USoA Sub-Account 6205 Donations, sub-account LEAP Funding.

The LEAP program provides assistance to eligible low-income consumers towards paying their electricity bills. This Emergency Financial Assistance Program helps those in need and funds are distributed through the Salvation Army_to customers that meet the set criteria to qualify for assistance. The Town of Milton has a number of customers who face financial hardships, the Company has been contributing $32,000 annually. Milton Hydro staff work closely with the LEAP program to ensure customers have knowledge of this grant and a provide direct contact to ensure timely assistance is given to customers in need.

As set out in the Report of the Board on Low Income Energy Assistance Program ("the LEAP Report"), the OEB determined that LDC's provide LEAP funding calculated as greater of 0.12% of a distributor's approved distribution revenue requirement, or $32,500.

Table 4-39 provides the supporting LEAP funding calculations for the 2023 Test Year:

Table 4-39 Calculation of LEAP Funding

Description	2023 Test Year
Service Revenue Requirement	$26,972,710
Funding % of Service Revenue Requirement	0.12%
LEAP Funding Calculated	$32,367
LEAP Funding included in 2023 OM&A (rounded)	$32,500

Milton Hydro is requesting $32,500 to support the LEAP program.

4.3.5.8. Charitable and Political Donations

Milton Hydro confirms that it has not included any charitable donations for recovery in its 2023 Test Year, with the exception of contributions to the LEAP program as identified in Section 4.3.5.7. Milton Hydro is requesting recovery for LEAP in funding in the amount of $32,500. Milton Hydro also confirms that it has not included any political contributions for recovery in its 2023 Test Year.

4.4 Workforce Planning and Employee Compensation

4.4.1 Introduction

This Exhibit, supported by the Human Resources study, per Attachment 4-3, Resource Optimization Review Report provides detailed information on Milton Hydro's strategies and approach to managing its human resources and ensuring operational capability and capacity to efficiently run the business. Key elements of the strategy are to:

- Maintain and enhance the reliability of its electrical distribution system;
- Deal with a shortage of skilled labour, while at the same time competing for new emerging skills;
- Aggressively implement a process improvement discipline and measures to promote enhanced business performance across the organization; and
- Address customer growth and nurture an evolving customer relationship.

Milton Hydro's Workforce Planning is focused on building a highly skilled and knowledgeable workforce and is intended to ensure operational capacity and capability – making sure it has the optimal talent, with the right level of skills & expertise to:

- execute its strategic objectives;
- mitigate the potential of operational risks;
- embed continuous improvement initiatives across the organization; and
- build a customer-focused approach where all employees consider how their decisions and outputs impact the customer experience.

The Town of Milton is one of the fastest growing communities in Ontario, and the fastest growing municipality with over 100,000 population in Canada from 2016 to 2021. The population of the Town of Milton grew from 87,000 in 2011, to 132,979 in 2021, with an average annual increase in population of 4,598.

The Growth Study that Milton Hydro commissioned Glen Schnarr & Associates Inc. (GSAI) to prepare provided Milton Hydro with information that it could use to inform its planning, investment decisions, and revenue projections in its Application. GSAI estimated that the annual population growth expected from 2021 to 2027 is 6,325, based on sources available to GSAI. Milton Hydro has used the GSAI report to help inform the degree to which growth will occur in the Town of Milton, especially in the more recent years of the GSAI study period.

More recently, based on most current data, the Integrated Growth Management Strategy Draft Preferred Growth Concept & Land Needs Assessment, Regional Council Workshop November 17, 2021, the Halton Region's population forecasts appear as though they are going to be downgraded for the period from 2021 to 2031 to an annual population growth of 4,900. This most recent population growth projection from the Halton Region was relied on by Milton Hydro with respect to longer term customer base growth trends.

Milton Hydro, relied on the GSAI report in this Application for the Test Year number of customers as GSAI state in their report that Beyond 2024 and into 2027, the accuracy of the projections begins to diminish as there are a greater number of factors that can influence the timing of development. Milton Hydro used GSAI's projection of residential customer growth of 950, plus 50 nonresidential customers to base its System Assess investments i.e., 1,000 new customers per year, during the DSP planning period.

Based on best information available to it at the time of preparing this Application, Milton Hydro expects that population and customer growth from 2021 to 2031 will be very similar to the historical growth experienced from 2011 to 2021.

Conversely, as its customer base continues to grow, Milton Hydro operates with a lower-than-average number of FTE's compared to its LDC peers. Based on the *2020 OEB Year Book of Electricity Distributors*, Milton Hydro's Customer to FTE ratio (808:1) is far above its other LDC comparators. Table 4-40 below, provides benchmarked comparisons against a mix of utilities with both larger and smaller number of customers. Including Temporary Staff and Students there were 55.3 FTE's in 2020 and the ratio is still high at 745:1 (customers served per FTE).

Table 4-40 Customers to FTE Ratio Comparisons

Description	Milton Hydro	Waterloo North	NPB	Energy+	Oshawa	Burlington Hydro	Synergy Corp.	Blue Water	Essex
# of Customers	41,221	58,438	56,979	67,303	59,486	68,568	56,887	36,919	30,661
# of Employees	51	119	121	121	76	97	129	117	40
Ratio:	808:1	491:1	470:1	556:1	782:1	706:1	441:1	317:1	766:1

Milton Hydro has historically operated a lean organization, whose structure as of 2020 had only 2 Executives and 2 Directors (senior level positions). Compared to its large-sized LDC peer group, Milton Hydro's Customer to FTE Ratio (808:1) is far above its comparators. In fact, out of all LDC's (small and large) Milton Hydro has the 5th 'highest' ratio of Customers served to FTE's.

Table 4-41 below, provides a comparison of the number of executive positions available, for some of the 2020 benchmarks outlined in Table 4-40.

Table 4-41 Executive Level FTE Comparison

Description	Milton Hydro	Waterloo North	NPB	Energy+	Oshawa	Burlington Hydro
# of Executives	2	5	6	7	4	6

Although operating a leaner organization can sometimes provide quicker decision-making, for Milton Hydro it affords minimal bandwidth between Executive and Supervisory positions. This results in more hands-on effort at the senior level, less developmental opportunities for Managers and Supervisors, and knowledge transfer & succession planning constraints.

This Exhibit provides detail on year-over-year changes in FTE's, from the 2016 Cost of Service filing to the 2023 Test Year.

Milton Hydro experienced a 100% turnover of its entire Senior Management Team (SMT) between August 2020 and January 2022. A new CEO was hired in August 2020, a new Director, Regulatory Affairs hired in September 2020, a new CFO hired in February 2021, and a new VP Distribution Services was hired in January 2022.

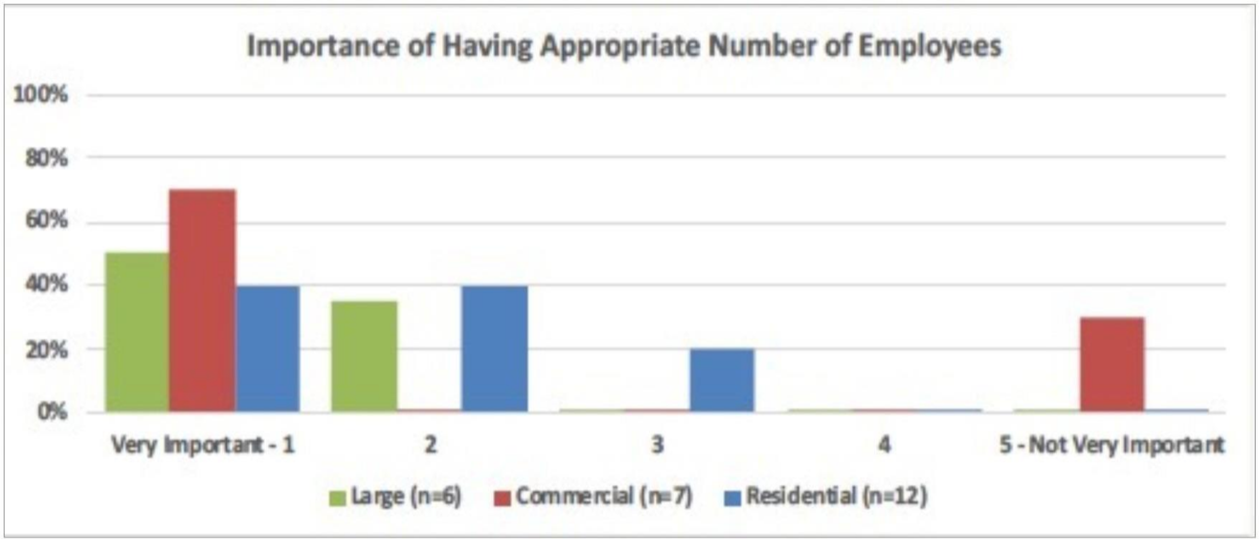
As referenced in Exhibit 1, Attachment 1-1, the organization developed Milton Hydro's 2.0 Strategy in early 2021. Milton Hydro’s strategy focuses on four (4) key objectives to build a stable, sustainable, and customer-centric utility.

Figure 2: Milton Hydro Strategy 2.0 Objectives

Milton Hydro conducted Customer focus groups in June 2021, as part of its Customer Engagement efforts (referenced within the Application, Exhibit 1, Attachment 1-7). Participants included residential, commercial/industrial and large-use customers. As part of the focus group the facilitator presented a summary of Milton Hydro’s 2.0 Strategy, its proposed OM&A spend and proposed increase in FTE’s over the next 3 years to support its objectives.

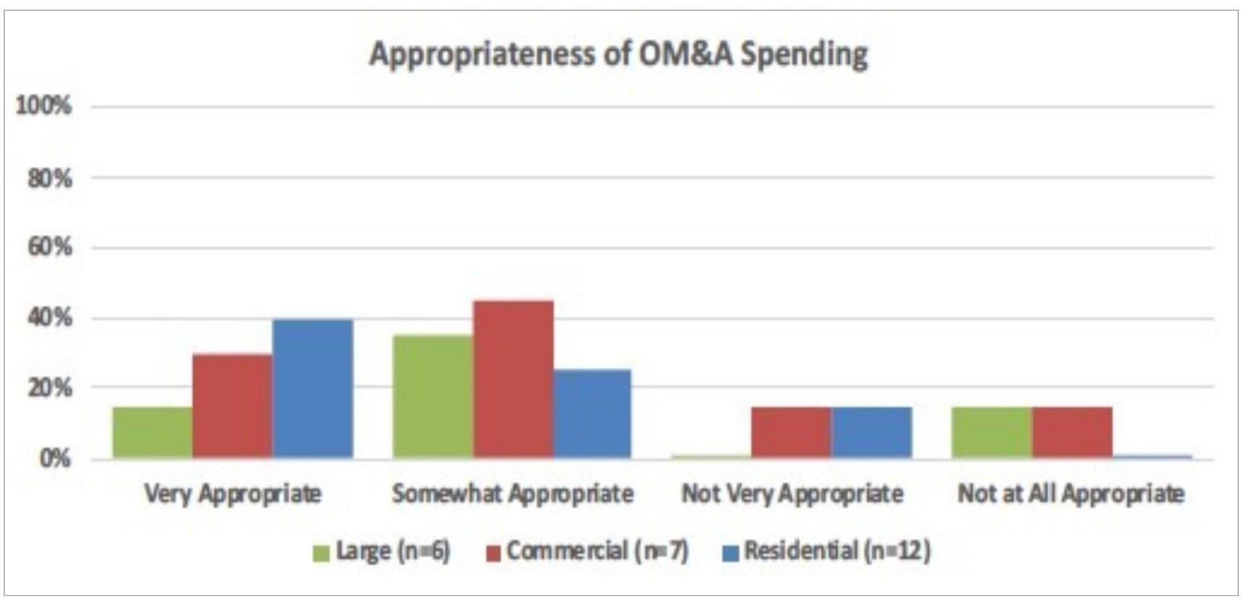
Milton Hydro’s Customers overwhelmingly (80% overall) rated it ‘very important’ or ‘important’ for the organization to manage its number of employees to effectively and efficiently manage its assets and services. Customers highlighted the importance that ‘new staff’ need to be hired before others retire to assure effective knowledge transfer.

Chart 4.9. Customers' Focus Group Response – FTE's



The Customers response to Milton Hydro's proposed OM&A spend was also supportive, with 65% rating the proposed level of spend as 'very' or 'somewhat' appropriate. Further, 45% reiterated the theme that Milton Hydro required more staff to support the rapid community growth – while 30% questioned 'how much rates would have to increase'.

Chart 4.10. Customers' Focus Group Response – OM&A Spend



With an entirely new senior leadership team, Milton Hydro engaged a 3rd party consultant in 2021 to undertake a *Resource Optimization Review* (Attachment 4-3). The project was initiated in response to the following concerns:

- Projected continued Customer growth;

- Lower-than-average FTE's per Customer than most LDC's;

- The ability and capability to effectively execute on Milton Hydro's 2.0 four (4) Strategy themes;

- Organizational capacity and capabilities may be lacking for the size and scope of the business; and

- Potential impacts of insufficient levels of accountability, decision-authority, business acumen and leadership capabilities.

Milton Hydro's *Resource Optimization Review (the Review)* (Attachment 4-3) has two distinct yet aligned focuses combining elements of Workforce Planning and Resource Optimization. *The Review* assessed Milton Hydro's trades and technical staff, inclusive of the front-line management required to lead and manage the trades groups and sought to determine the right size and right skills of its management & professional staff required now and in the future. The *Review* focused on positions and roles up to and including the director level.

The Review provides insight into what trends are impacting the labour market, and what and where Milton Hydro could focus on over the next five years to achieve its strategic objectives and meet the continuously evolving demands of its Customers and Stakeholders. *The Review* put forward suggested new roles to fill the gaps identified in *The Review* – attempting to 'right size' and 'right skill' the organization.

The consultant interviewed Milton Hydro's senior leadership team (SLT) consisting of:

- CEO;

- CFO;

- Director, Regulatory Affairs;

- Director, Engineering;

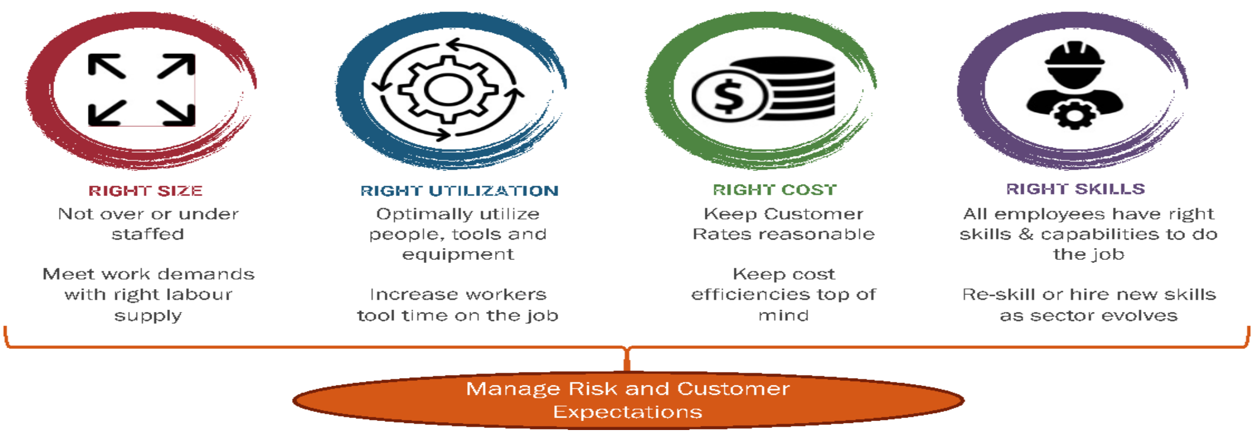
- Manager, People & Culture; and

- contracted Manager Health & Safety (H&S).

The interviews focused on attaining a thorough understanding of the current strengths and challenges, as well as affirming assumptions on functional business needs now, and into the future. The Plan conclusions are based strictly on data provided by Milton Hydro. The consultant did not undertake an internal review to validate the process and/or control functions. The organization set workforce optimization goals, as part of the Review to guide its decisions and direction for both Workforce Planning and Resource Optimization.

Chart 4.11. Workforce Optimization

Milton Hydro's Workforce Optimization Goals



The Review concurred that Milton Hydro has maintained a workforce well-below the average of its large-sized peers for the past number of years. *The Review* identified where increased staffing levels would benefit Milton Hydro in: *meeting the rapid and sustained growth of the Town of Milton and its Customer base; augmenting organizational expertise & capacity; enhancing internal controls and processes; and, sustaining an efficient workforce with the right tools and skills now and into the future.*

The Review highlighted an opportunity for Milton Hydro to increase productivity, enhance business performance and focus on being a customer-centric organization, where all employees work towards enhancing the customer experience – by hiring a specific and dedicated process improvement role, with experience in Six Sigma and Lean principles.

Milton Hydro took the consultants *Review* into consideration, utilizing and building on elements and analysis within *The Review* to derive the projected level of FTEs for 2021 to 2023.

Milton Hydro considers its current level of staffing unsustainable. The organization does not have sufficient internal bandwidth nor has it, over the past many years, proactively invested in succession or resource planning. Continued minimal investment in hiring the right skills and expertise and not operating at optimal capacity, has the potential to impact business processes.

Milton Hydro initiated the hiring of new roles in 2021, to increase capacity and enhance current skills and expertise, and will continue to hire through to the 2023 Test Year. The new hires will offset the challenges of minimal internal bench-strength and ensure the organization has the capability to execute business processes and initiatives effectively. This will mitigate potential risk to the business as well as deliver favourable impacts to business processes.

Milton Hydro has provided in Table 4-42 detailed year-over-year changes in FTE's from 2016 to 2020, and explains the rationale for each new position embedded in the counts for 2021 to 2023.

Table 4-42: Year-Over-Year Changes in FTE's

Description	2016 Actual vs. 2016 OEB Approved	2017 Actual vs. 2016 Actual	2018 Actual vs 2017 Actual	2019 Actual vs. 2018 Actual	2020 Actual vs. 2019 Actual	2021 Historical vs. 2020 Actual.	2022 Bridge Year vs. 2021 Historical	2023 Test Year vs. 2022 Bridge Year
Number of Employees (FTEs including Part-Time)								
Management (including executive)	0.2	(0.2)	0.3	0.6	0.3	(0.9)	4.7	1.0
Non-Management (union and non-union)	(1.5)	0.4	(0.3)	(2.2)	(1.3)	4.1	6.5	7.0
Total	**(1.3)**	**0.2**	**(2.5)**	**(1.6)**	**(1.0)**	**3.2**	**11.2**	**8.0**

4.4.2. Workforce Planning

Milton Hydro provides detailed information on its workforce planning, employee complement, compensation, and benefits within this Section. As part of its workforce planning, Milton Hydro considers the challenges in maintaining an optimal trades & technical workforce. As part of its workforce planning strategies, it has begun in-sourcing more of its capital and maintenance work to mitigate the potential of an insufficient or under-skilled workforce pipeline. Milton Hydro's workforce planning is aligned to its core strategies and the future direction of the organization. The need to drive innovation, increase productivity and enhance the customer experience, has also been integrated into how Milton Hydro approaches workforce planning and influences its resource planning over the next five years.

Milton Hydro planning takes a broad view of its trades group and trades supervisory staff, inclusive of those skills that are required to maintain and grow its distribution system and meet the changing demands of its customers over the next five years and beyond. Its workforce planning identifies gaps between the labour *demand* of the organization and the available workforce *supply*, leading to initiatives and actions used to close the *gaps.*

Matching the resource capability with the work demands in the electrical distribution sector requires both short and long-term planning. Numerous contributing factors are impacting Milton Hydro's resource planning, including:

- An industry-wide shortage of skilled labour;

- Emerging technological advancements that will change trades/technical know-how/skills;

- Increased competition for new skills; and

- Responding to its rapidly growing community and customer base.

The aim is to ensure operational capacity and continuity by supplying the right talent with the rights skills, within the right structure, at the right time.

Milton Hydro's workforce has undergone significant changes since 2016. During the period 2016 to 2021, Milton Hydro experienced a 30.4% workforce turnover, including a 100% turnover of its CEO and senior leadership team between 2020 and 2021. Although there are only 2 non-management (union) employees eligible to retire over the next five years (2022-2026), approximately 21% of management employees are eligible to retire. Historically since 2016 Milton Hydro's experience has been that 80% of those employees eligible to retire, do in fact, retire in their year of eligibility.

Milton Hydro has been presented with challenges since its 2016 Cost of Service, which has informed and influenced its workforce planning & recruitment efforts and provided opportunities to enhance resource optimization:

Competitive Labour Market & Skills Shortage: Milton Hydro operates in an extremely competitive labour market, and continues to experience challenges recruiting for certain positions, such as: engineers/engineering technicians; power line and system control operators; regulatory expertise; and technology roles. Milton Hydro has not in the past hired apprentice power line technicians and intends to begin advance hiring apprentices in 2024, who dependent on the trade, require four to seven years of training to attain full proficiency. Section 4.4.2.1.1 provides details of the challenges Milton Hydro is experiencing and its recruitment strategies to: mitigate the risk of operating with an insufficiently trained workforce; and add capacity and capabilities to achieve its optimal number of resources.

Table 4-43 Years to Reach Proficiency

Years to reach proficiency		
Powerline Technician	5	May require longer for lead hand positions
Substation Maintainer	5	May require longer for lead hand positions
Meter Technician	4.5	May be able to work on limited meters in first two years
Control Operator	5	May require longer for lead hand positions
Design Technician	4	Engineering design work requires college degree and practical work experience (hours)
Distribution Engineer	4	Takes for years to qualify for P.Eng.
Supervisory Positions	5-7	Requires leadership, right competencies and business skills

Managing Turnover: The high rate of turnover (30.4%) between 2016 to 2021 results in managing a large number of vacancies and is exacerbated by recruitment challenges. Milton Hydro did not employ a dedicated Human Resource professional, as part of its employee complement, from 2016 to 2019. In 2019 it hired a HR Generalist, in a contract position. In 2021, a dedicated Manager, People & Culture was hired to support the organization to oversee recruitment, training and employee onboarding.

Changing Workforce: Milton Hydro's workforce planning recognizes the impact a changing workforce could have on the business: a vast multi-generational workforce; and potential knowledge and expertise leaving - against the challenges of recruiting the right skills and talent over the next five years.

Network Control Room Operations: Historically Milton Hydro has outsourced its Control Room operations. Milton Hydro retained a third-party expert, AESI, to undertake a feasibility study of costs and benefits of implementing an in-house control room as compared to the costs and benefits of various outsourcing and hybrid models, among other things. Milton Hydro prepared a Business Case justifying an in-house System Control Room. Relying on its strategic objectives and needs, as further discussed in Exhibit 1, section 1.2, and AESI's control room feasibility study findings, Milton Hydro has determined maintaining control and operation of this function is in the best interests of the Company and its customers (Section 4.4.2.4).

In-House vs. 3rd Party Contracted Trades Work: Milton Hydro's 2016 Test Year Approved headcount included 10 Power Line Technicians (PLTs). Subsequent to that, a decision was made to outsource a large percentage of construction work to third-party contractors. Between 2016 and 2020, PLT FTE's dropped from 10 to 5, due to the outsourcing decision and in part due to difficulties filling vacancies caused by market constraints. In 2021 Milton Hydro began increasing its PLT complement and will employ 8 PLT's in 2022, resulting in a change from 10 PLT's in 2016 to 8 PLT's in 2022. This results in an overall reduction in Trades & Technical positions by 1.5 FTE's since 2016, comprised of:

◦ reduction of PLT's, -2.0 FTE,

◦ reduction of a Lead Hand, -1.0 FTE,

◦ an increase of an Engineering Technologist, +1.0 FTE and

◦ an increase of a SCADA Technician +0.5 FTE to support in-sourcing the work.

Milton Hydro has reduced its contractor costs, with no impact to its Capital and/or Operating budgets. The qualitative benefits are further outlined in Section 4.4.2.5.

Productivity & Continuous Improvement: Productivity and efficiency improvements are a priority to Milton Hydro; so that it can offset and minimize FTE increases against its growing customer base; optimize business processes & continuous improvement initiatives; and maintain reasonable impacts on customer rates (referenced in 4.4.2.6)

Information Technology & IT Infrastructure Security: It is hard to overstate the impact technology will have on electricity in the immediate future. Emerging technologies will change both the size of the sector's labour force and its composition. Modernizing the system will not only improve the way the sector distributes and stores power – it will also provide jobs for workers who have the right skills and knowledge, combined with the ability to continuously adapt.

As technology becomes more complicated, there is an increased need for cyber security professionals to ensure compliance and security requirements are met.

Sufficient Management Bench Strength, Capability & Capacity: Bench strength is the organization's ability to immediately fill critical roles with a talented internal pipeline, due to the loss of an employee. Capability depth is having a sufficient number of leaders and professionals who are fully competent and proficient in their role, having the right skills and expertise. Capacity is defined by the maximum amount of work that can be completed by employees in a given period, whereby insufficient capacity leads to some leaders continually doing the 'urgent' and less of the 'important' work, posing a potential risk to the business.

4.4.2.1. Competitive Labour Market & Skills Shortage

4.4.2.1.1. Trades & Technical Workforce:

The electricity sector is not a 'just in time industry'. The workforce is highly skilled and educated with the majority of its jobs requiring post-secondary education and long lead times to reach full competency and proficiency. Milton Hydro continues to compete for workers both within and outside of the sector. With the exception of some specialized trades, most occupations within the sector share skills that are transferable to other industries. In particular, the labour market for engineers; construction; and Information Communication Technology (ICT) jobs all share occupations and skills that are utilized across a vast number of businesses. As the sector becomes more sophisticated, demand will increase for employees able to work in an ever-changing, diverse, interconnected, and high-tech electricity sector.

Milton Hydro has experienced, particularly in the past three years, a rise in its employees being sought after by other organizations and utilities. Employee turnover increased in part due to a competitive labour market, which challenges the organization to maintain market competitive salaries, wages and benefits to attract and retain workers. With respect to its Trades & Technical staff, between 2018 and 2021, four tradespeople left Milton Hydro's employ. This represents 19% turnover in last three years.

Milton Hydro continues to enhance its recruitment and retention strategies. To maintain the resources needed and to sustain its workforce pipeline, Milton Hydro is: advance hiring apprentices; increasing its PLT complement; and, bringing its Control Room function in-house to mitigate reliance on third-party contractors. Each of these approaches will enhance Milton Hydro's FTE complement for those positions that are becoming more and more difficult and challenging to recruit. More importantly, they will support better reliability and response time for customers and with less contractor reliance, provide Milton Hydro more control over its response, interactions and service to its customers and community.

Table 4-44 Trades & Technical Workforce Complement

	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Historical	2022 Bridge Year	2023 Test Year
Trades & Technical Staff									
Power Line Technician	10.00	8.96	5.50	6.25	5.08	5.00	5.16	8.00	8.00
Lead Hand	**4.00**	**3.00**	**3.00**	**3.00**	**3.00**	**3.00**	**3.00**	**3.00**	3.00
Metering Technician	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
SCADA/OMS Technician	0.40	0.00	0.00	0.50	1.00	1.00	1.00	1.00	1.00
Engineering Technologist / Technicians	4.00	4.00	4.00	4.00	4.00	4.00	4.00	5.00	5.00
Total Trades (FTEs)	**21.40**	**18.96**	**15.50**	**16.75**	**16.08**	**16.00**	**16.16**	**20.00**	**20.00**
Trades Supervisory Staff									
Operations Supervisor	2.00	2.00	2.18	2.05	2.00	1.24	1.00	1.00	1.00
Operations Manager	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00
Metering Supervisor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Engineering Supervisor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Trades Supervisory FTEs	**3.00**	**3.00**	**3.18**	**3.05**	**3.00**	**2.24**	**2.00**	**3.00**	**3.00**

4.4.2.1.2. Management Staff

Milton Hydro is experiencing the same level of competitiveness for management positions, inclusive of its front-line Supervisor positions. Recent recruitment efforts have resulted in a smaller than normal pool of potential qualified candidates. With the COVID-19 Pandemic upon us, and an uncertainty of what the near future may look like, Milton Hydro is not only experiencing recruitment issues, but also retention challenges (Section 4.4.2.2). Many candidates, especially in the technology fields, are seeking the ability to work remotely permanently, and not be required to work in an office environment. Milton Hydro has implemented a vaccine mandate requirement for all 'new' employees, which resulted in the loss of a high potential candidate who was being recruited for a manager level position in early 2022.

4.4.2.2. Managing Turnover

Milton Hydro's total turnover rate encompasses retirements and attrition due to employees being terminated or leaving Milton Hydro's employ for other reasons. Milton Hydro's historical trend from 2017 to 2021 is such that 80% of those eligible retire in their year of eligibility and the table below makes this assumption from 2022 to 2026.

Table 4-45 Retirements

Retirements (Eligible Employees)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	TOTALS
Technical & Trades (Union)												
Line Persons												**—**
Lead Hands						1.0						**1.0**
Meter Technicians							1.0					**1.0**
GIS Technologist												**—**
Engineering Technologies												**—**
SCADA Technician												**—**
Engineering Clerk			1.0									**1.0**
Office/Support Staff (Union)/ Non Management (Non-Union)												
Accounting Clerk												**—**
Material Procurement												**—**
Billing Clerk												**—**
AMI Operator												**—**
Customer Service Representative											1.0	**1.0**
Non-union/Professional			1.0			1.0					1.0	**3.0**
Management												
Executive			1.0			1.0						**2.0**
Directors				1.0					1.0			**2.0**
Managers		1.0						2.0				**3.0**
Supervisors		3.0	2.0			1.0		1.0				**7.0**
TOTALS	**—**	**4.0**	**5.0**	**1.0**	**—**	**4.0**	**1.0**	**3.0**	**1.0**	**—**	**2.0**	**21.0**
MANAGEMENT *	—%	23.26%	17.65%	5.78%	—%	10.99%	—%	13.64%	4.35%	4.35%	—%	
NON-MANAGEMENT (union & non-union) *	—%	—%	4.61%	—%	—%	5.39%	2.43%	—%	—%	—%	3.66%	
Total % FTE Retirements						***23.9%***					***9.7% *****	
MANAGEMENT % Retirements						***57.4%***					***18.5% *****	
*Estimated against 'average' FTE's throughout the period												
** Eligible retirements reduced 80% (historical actual trend of those who are eligible and actually retire)												

In Milton Hydro's previous COS Application (EB 2011-2025), managing employee turnover was highlighted as a significant challenge. This trend has not changed, from 2017 through to 2021 Milton Hydro experienced a substantial number of retirements, particularly in its management group, with over 57.4% retiring in a five-year period. Although this organization trend will slow from 2022-2026, the management group will again experience a retirement rate of almost 18.5%.

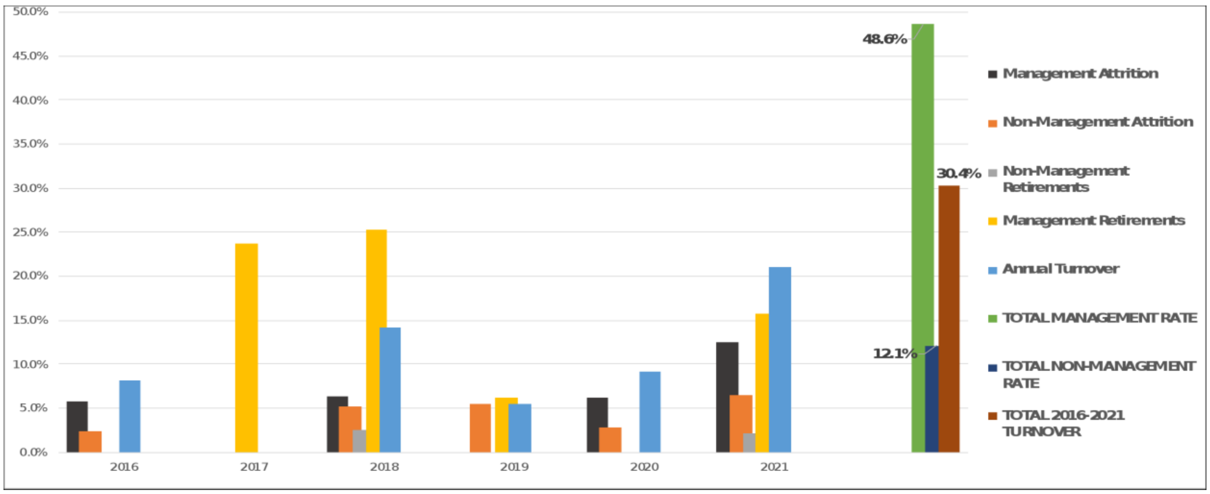
Table 4-46 Non-Retirement Attrition

Non-Retirement attrition consists of employees who have left Milton Hydro's employ either through termination, or voluntary exit. Table 4-46 provides the year-over-year attrition % impact by employee category.

Attrition & Turnover	2016	2017	2018	2019	2020	2021	TOTALS
Technical & Trades (Union)							
Line Persons			2.0	1.0			**3.0**
Lead Hands							**—**
Meter Technicians							**—**
GIS Technologist							**—**
Engineering Technologies	1.0						**1.0**
SCADA Technician							**—**
Engineering Clerk							**—**
Office/Support Staff (Union)/ Non Management (Non-Union)							
Accounting Clerk						1.0	**1.0**
Material Procurement					1.0		**1.0**
Billing Clerk							**—**
AMI Operator						2.0	**2.0**
Customer Service Representative				1.0			**1.0**
Non-union/Professional							**—**
Management							
Executive							**—**
Directors	1.0					1.0	**2.0**
Managers							**—**
Supervisors			1.0		1.0	1.0	**3.0**
TOTALS	**2.0**	**—**	**3.0**	**2.0**	**2.0**	**5.0**	**14.0**
MANAGEMENT	5.81%	—%	5.78%	—%	5.49%	11.56%	28.57%
NON-MANAGEMENT (union & non-union)	2.33%	—%	4.93%	5.21%	2.70%	7.28%	22.17%
Total % FTE Attrition / Turnover	3.44%	—%	5.18%	3.55%	3.62%	8.55%	24.10%

In Table 4-46, attrition percentages utilize the same average FTE's per year and overall, as Retirements Table 4-45. Milton Hydro experienced relatively consistent attrition amongst its Trades & Technical and Union staff from 2016 to 2021. Management attrition was consistently over 50.0% higher than Union staff and peaked at 11.56% in 2021 – a 110% increase relative to 2020.

Chart 4.12. Total Turnover Rates



Milton Hydro has experienced a high turnover rate from 2016-2021, substantially driven by management retirements (57.4% Table 4-45) and a management attrition rate of 11.56% in 2021. Milton Hydro's turnover rates are higher than the industry average.

According to the Electricity Human Resources Canada, Workforce in Motion Study (2017-2022), turnover for Utility Managers in 2017 was 1.7%, and projected turnover for this same group to increase to 2.2% in 2019.

Milton Hydro's high turnover rate has challenged the organization to fill vacancies and maintain its budgeted FTE headcounts. Challenges include:

- Organizational priorities shifting from proactive to reactive, resulting in delays filling vacancies and budgeted positions;

- The duration of the hiring process putting stress on the organization to accommodate the added workload resulting from less workers/leaders;

- Potential risk of erosion of work and safety processes, if knowledge of experienced workers and leaders is not transferred prior to individual employee departures;

- 50% of the non-retirement turnover resigned and left Milton Hydro to work elsewhere. Of the 50%, four were from the Trades & Technical complement. Milton Hydro experienced difficulty hiring qualified trades during this period;

- More experienced Trades, front-line supervisors and managers are required to work overtime and/or put in extended hours to complete the work of vacant roles; and

- Potential negative impact to employee engagement and customer satisfaction if adequate resources are not available.

Turnover of employees, either through retirement or attrition, impacts the business in many ways. From the time of an employee's departure to posting/advertising the position, interviewing and hiring new staff, it can take many months, and cross over from one budget year to the next. The impacts to the business can be substantive.

According to SHRM's Report[3] – *Retaining Talent, A Guide to Analyzing & Managing Employee Turnover*[4], "Employee departures cost a company time, money and other resources. Research suggests that direct replacement costs can reach as high as 50%-60% of an employee's annual salary, with total costs associated with turnover ranging from 90%-200% of annual salary."

[3] Society for Human Resource Management.

[4] Retaining Talent, A Guide to Analyzing & Managing Employee Turnover, by David G. Allen, Ph.D., SPHR

SHRM's research provides a breakdown of costs that impact the company when there is employee turnover such as:

Financial	HR staff time (exit interview, payroll administration, benefit changes)
	Manager's time (retention attempts, exit interview)
	Accrued paid time off (Vacation, sick pay)
	Temporary coverage (overtime, contingent/ contract employees)
Replacement Costs	Hiring inducements
	Hiring manager and department/ unit employee time
	Orientation program time and materials
	Human Resource staff induction costs (payroll, benefits enrollment)
Training Costs	Formal training (trainee and instruction time, materials, equipment)
	On-the-job training (supervisor and employee time)
	Productivity loss until proficiency reached
	Mentoring (mentor's time, travel)

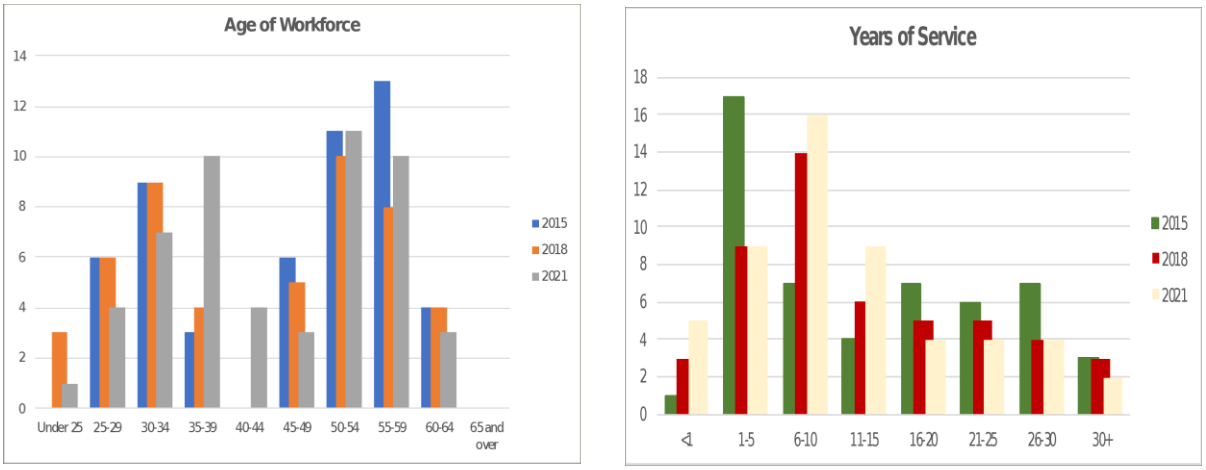
The SHRM Report finds that "turnover is tougher on smaller organizations". The loss of key employees can have a particularly damaging impact on small organizations such as: departing workers more likely to be single incumbents and possess a particular skill or knowledge set; results in a smaller internal pool of workers to cover the lost employee's workload until replaced; and the organization has fewer resources available to cover replacement costs.

4.4.2.3. Changing Workforce

An Electricity Human Resources study reports the age distribution of the electricity sector workforce has changed since its previous 2011. The study indicates however, it does not anticipate changes to turnover and retirements rates, which have been increasing throughout the sector. In turn, the study indicates this will have an effect of a lower representation of workers under 25 in the sector compared to the general workforce.

Table 4-11 below, identifies the distribution of Age and Years of Service of Milton Hydro's workforce, comparing 2015, 2018 and 2021. Milton Hydro's age distribution remains fairly consistent for the 50-54 years' old but has decreased slightly at 55 and above. Overall, Milton Hydro's workforce is younger in 2021 than 2015, particularly in the 35-39 range. Since 2015 Milton Hydro's workforce has become more seasoned, with only 26% with 5 years or less experience, compared to 35% in 2015.

Chart 4.13. Milton Hydro Employees' Age & Years of Service Distribution



As employees retire and high turnover rates continue, Milton Hydro is also faced with recruiting the 'Next Generation' of workers, while integrating and training four distinct generations of workers.

These two trends are producing the most multi-generational workforce in history for workplaces. There are some substantive differences between the Old and New World within a multi-generational workforce. For older workers, the two largest challenges will be training & developing skills and expertise to meet the new digital environment and responding to the health and wellbeing needs of an aging population. Milton Hydro's multi-generational workforce has many layers: Baby Boomers: Gen Xer's; Millennials (Generation Y); and Generation Z – which began its emergence into the workforce in 2018.

For new and younger employee's, the challenge will be identifying what motivates, engages and drives them. Retaining new younger talent will take creative strategies and initiatives, and acceptance that change is necessary to build and retain a collaborative and innovative workforce over the next five years and beyond.

Milton Hydro intends to boost its recruitment and retention processes – by strategically evolving its tactics and adapting its hiring processes – building a coherent and proactive approach to finding, attracting and hiring the required talent and skills.

4.4.2.4. Network Control Room Operations

Since 2014, Milton Hydro has been outsourcing its control room functions to other Ontario utilities. This arrangement no longer meets Milton Hydro's and its' customers' needs and objectives. In late 2021/early 2022, Milton Hydro undertook a thorough strategic analysis to:

a. determine the most efficient and cost-effective way to operate its constantly evolving distribution system in a safe and reliable manner,

b. support the capability to restore electricity as efficiently as possible,

c. meet growing customer needs and expectations, and

d. be future ready, including having the ability to manage the increasing number of DERs.

To assist with its analysis, Milton Hydro retained a third-party expert, AESI, to undertake a feasibility study of costs and benefits of implementing an in-house control room as compared to the costs and benefits of various outsourcing and hybrid models among other things. Based on the comparison of the size, complexity, and age of Milton Hydro's electricity distribution system, to similar utilities in Ontario. AESI concluded that MHDI is at the stage where a 24x7 control room will provide significant benefits to the utility and its customers. See Attachment 4-2 AESI Report - Control Room Cost Benefit Analysis.

Attached is the business case prepared by Milton Hydro to justify an in-house System Control Room. Milton Hydro relied on the following when preparing the Business Case:

a. Milton Hydro's strategic objectives and needs, as further discussed in Exhibit 1, sub-section 1.2,

b. AESI's control room feasibility study findings, and

c. Customer needs and preferences,

Milton Hydro assessed the following three alternatives:

i. 24/7 in-house control room;

ii. In-house day-shift control room operations and on-call after hours (SCADA in operator's home);

iii. Outsource 24/7 coverage.

Milton Hydro concluded that it needs to construct a control room as outlined in its business case.

Staffing a 24/7 system control room requires competent staff that understand electricity distribution systems and the operating systems, and how to manage them all safely and in a timely manner, covering a full 168-hour week. Operators need to be fully present and engaged. Everything from ergonomics to the staffing compliment is considered to maintain a safe operational environment and healthy team. AESI's report indicated that to provide balanced coverage, that Milton Hydro would need a team of six shift operators and a supervisor.

The staffing complement needed to operate the 24x7 System Control Room is 6 FTEs as detailed in the attached business case. See Attachment 4-1 Business Case: 24/7 System Control Room & Operations.

Milton Hydro plans to construct a control room within its facilities in 2022, along with the hiring and training of two control room operators. Late in 2022, with four additional operators to be recruited to start in January 2023.

4.4.2.5. In-House vs. 3rd Party Contracted Line Work

Typically, in large-sized LDC's, a large percentage of the planning, work and operating on the distribution plant is performed by internal labour. The services of third-party power line contractors are used to assist with the construction of large capital projects and undertake work the utility is unable to complete, due to resource restrictions, the need for specialized equipment and/or the ability to complete a project in prescribed timelines.

Often, the civil construction work and tree trimming are performed by contractors. Some technical planning and design may also be performed by engineering consulting firms. Maintenance on the distribution plant is usually predominantly performed by internal staff.

To meet the asset management needs of the distribution plant, LDC's rely on a highly skilled core of Trades & Technical staff to perform the majority of the work. Services of contractors are often used for work that is not electrical utility specific (e.g., civil construction and tree trimming), as well as to assist in the managing varying seasonal workloads, and during intense power emergency situations.

Milton Hydro's historical ratio of contracting out (80%) vs. in-house work (20%) is unusual against its peer LDC's. Milton Hydro conducted a short survey of five of its large-sized peers. The survey showed Milton Hydro's ratio almost the opposite of its peer comparators. The aggregate comparators did not include Milton Hydro.

AGGREGATE OF 5 LDC'S	
In-House	Contracting Out
73.0%	27.0%
Range	
60/40 to 90/10	

MILTON HYDRO 2021	
In-House	Contracting Out
20.0%	80.0%

Milton Hydro increased its *Power Line Technicians* (PLT) headcount by 2.8 FTE's in 2021 due to its decision to in-source more construction work, previously undertaken by third-party contractors. Milton Hydro will undertake to make a shift to more in-sourcing of work so the ratio of in-house vs contracting out increases in favour of in-house. Milton Hydro expects that there will be no incremental costs associated with this shift, with no impact on its capital or maintenance budgets. The cost of in-sourcing the work, fully burdened, is equal to the reduction of third-party contracting costs the Company will realize.

There are also qualitative benefits of shifting the ratio and in-sourcing work performed by Milton Hydro FTE's, such as:

- Experts are predicting continued and more severe extreme weather conditions. Milton Hydro's customers share this concern as reflected in the Customer Engagement Focus Group results, and clearly indicated they support the Company being sufficiently staffed to deal with severe weather conditions, quicker restoration time and improved predictive reliability to mitigate outages during storms Exhibit 1 sub-section 1.7.4.2 UtilityPULSE Customer Satisfaction Survey, Table 1-18 Top 5 Customer Planning Priorities. priority #2;

- In-sourcing work decreases Milton Hydro's current reliability on outside contractors performing restoration work; and

- Maintaining optimal PLT's helps mitigate against recruitment and market supply challenges for qualified trades.

4.4.2.6. Productivity & Continuous Improvement

In late 2021, Milton Hydro hired a *Process Improvement Officer* ("PIO"), adding a new role and discipline to the organization. As a Lean Six Sigma black belt certified professional, the incumbent's focus is to deliver process innovation and continuous improvement initiatives across the organization. Institutionalizing a Six Sigma discipline approach builds a customer-centric and efficiency mindset, with employees focused on value-add activities and continuous improvement opportunities. The PIO will train Milton Hydro's employees beginning in 2022 with the goal to attain Six Sigma Yellow Belt certification for its employees. Yellow Belt training teaches the relationships between improving quality processes and the organization's profitability. A certified Six Sigma Yellow Belt has received introductory training in the fundamentals of Six Sigma. Employees will be trained to identify, monitor and control waste and enhance productivity. See Exhibit 1 subsection 1.9 FACILITATING INNOVATION.

Such training enables employees to recognize waste in their respective processes and provides them the tools and concepts to act on eliminating and/or reducing redundant activities & processes.

As referenced in the Application (Exhibit 2, Attachment 2-2 DSP, Appendix F - PwC IT Roadmap), Milton Hydro's IT Strategy - *Optimizing Performance and Delivery* sets out the roadmap for transformational improvement initiatives, in part, by enhancing business process automation. The PIO will support these initiatives with the objective of automating manual and highly repetitive activities (where reasonable to do so, and not just for the sake of implementing automation).

4.4.2.7. Information Technology & Infrastructure Security

The need to improve the security of data has increased since Milton Hydro's 2016 COS Application. Security of Milton Hydro's customer information and protection of their privacy continues to be a critical focus. The risk of security breaches and exposure to cyber-attacks within the electrical energy sector has grown substantially with the implementation of Smart Grids, Smart Metering and Self-Generation technology. Increased use of automation, different communication networks, and the use of wireless networks, data flows, hand-held electronic devices and the internet of things (IoT) have created real-time data exchange between entities within the province. This has resulted in increased cyber security risks within the Ontario energy sector.

Cyber-attacks occur daily and are increasing in frequency, particularly with the substantive increase of employees working remotely and companies are struggling to erect sufficient fire-walls and protections. The OEB's Cyber Security Framework acknowledges the criticality of this threat to utility operations and prescribes regulatory requirements to address these risks. To address these changes and mitigate IT security risks, Milton Hydro will hire a *Director IT & Client Services* and an *IT Infrastructure & Security Specialist*, both in 2022.

4.4.2.8. Sufficient Bench Strength, Capability & Capacity

Milton Hydro has historically operated a lean organization, with fewer senior level roles and the highest Customers per Employee ratio of its LDC peers (Section 4.4.1). It is also experiencing a reduced breadth of bench strength between its Supervisors and Executive, resulting in a vast majority of decisions currently being made by the CEO and CFO - which was an accepted and encouraged practice by past management. This past practice has led to a flatter organization with a 'top down' organizational style that centralized decision-making. This has resulted in insufficient accountability and/or staff operating at a more junior level.

Milton Hydro considers its current level of staffing unsustainable. The organization does not have sufficient internal bandwidth nor has it, over the past many years, proactively invested in succession or resource planning (Section 4.4.1).

Milton Hydro began hiring in 2021 to increase its capabilities and bench strength and will continue to hire critical new roles through to 2023 (Table 4-49), in part to:

- Increase its strategic and broad organizational leadership by adding additional executive roles bringing its Executive FTE's from 3 (2016 through 2021) to 5 (2022).

- Provide senior level oversight and enhanced focus on Internal Controls (Reference Appendix 4.4.1. Introduction), relative to maintaining: sufficient levels of authority; defined decision-making responsibilities; and, adequate expertise to identify & mitigate potential internal control concerns;

- Enhance its security and employee access and control authority levels & cyber security requirements;

- Improve and build upon its Health & Safety program and initiatives;

- Enhance procurement practices to reduce and/or define single source and preferred vendor practices, enhance vendor quality and assessment reviews and awarding of contracts, and develop and operate under best practice procurement policy and procedures;

- Assess current manual processes to either enhance or automate the process and reduce the risk of manual input;

- Add capacity to cross-check and add authority levels - ensuring the adequate review of financial and regulatory documents and filings allowing multiple reviews and touchpoints; and

- Drive decision-making and responsibility to the right operational level, empowering leaders to take ownership within their defined areas of accountability.

4.4.3. Pandemic Impacts & Post Pandemic Productivity

The unexpected arrival of the COVID-19 Pandemic in early 2020 has validated the need for more advanced mobile and digital technologies, nimble workplaces and a resilient workforce and leadership team. There are many unknowns as to the impact and protracted repercussions the situation will have on the business relative to: longer-term productivity effectiveness with the majority of its workforce working remotely and maintaining sufficient capacity to operate the business during highly contagious variants. All factors may continue to impact Milton Hydro's ability to attract and recruit staff and it's the ability to effectively build cohesive and collaborative teams without face-to-face interactions. Multiple employees and leaders have been communicating virtually for almost two years, with many having never met their employee/ manager in person.

4.4.3.1 Staffing & Compensation

Milton Hydro's employee complement, compensation and benefits are set out in Table 4-13, Board Appendix 2-K below.[5]

The number of FTE's is based on the computation of the number of employee positions throughout each of the calendar years. The parameters for calculating FTE's are based on: an

[5] The FTE count in Appendix 2-K is higher than reported in RRR filing due to inclusion of temporary staff and students.

employees' start and end date, using total number of days worked divided by total days in a year. and apply to all FTE categories (below). In the calculation of Milton Hydro FTE's, it employs four types of employees with each type incorporated into the calculation of FTE:

- Full-Time Employees typically work anywhere between 35-40 hours and are entitled to fringe benefits;
- Part-Time Employees work less than 35 hours per week and deliver support based on seasonal and/or business needs;
- Temporary Employees are hired to cover for absent employees (such as those who are on maternity or disability leave) and temporary vacancies or fill gaps in the workforce; and
- Students are employed to typically cover seasonal vacation coverage for high demand areas of the business.

The salaries and wage amounts include all salaries and wages paid, inclusive of incentive pay for management, overtime, vacations, floater holidays, sick leave, bereavement leave, union meetings and other miscellaneous paid leave.

The benefit amounts include the employer's portion of statutory benefits (CPP, EI and EHT), employer contributions to OMERS and WSIB and Milton Hydro's costs for providing extended health care, dental, long-term disability and life insurance.

Table 4-47 Appendix 2-K Employee Compensation

Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Historical	2022 Bridge Year	2023 Test Year
Number of Employees (FTEs including Part-Time)									
Management (including executive)	17.0	17.2	17.0	17.3	17.9	18.2	17.3	22.0	23.0
Non-Management (union and non-union)	44.5	43.0	43.4	40.6	38.4	37.1	41.2	47.7	54.7
Total	**61.5**	**60.2**	**60.4**	**57.9**	**56.3**	**55.3**	**58.5**	**69.7**	**77.7**
Total Salary and Wages including overtime and incentive pay									
Management (including executive)	$2,301,118	$2,273,777	$2,328,068	$2,314,795	$2,494,584	$2,819,608	$2,867,076	$3,448,908	$3,808,754
Non-Management (union and non-union)	$3,513,853	$3,121,448	$3,352,832	$3,146,557	$3,053,362	$3,150,129	$3,462,872	$4,239,048	$5,335,691
Total	**$5,814,971**	**$5,395,225**	**$5,680,900**	**$5,461,352**	**$5,547,946**	**$5,969,737**	**$6,329,948**	**$7,687,956**	**$9,144,445**
Total Compensation (Current + Accrued)									
Management (including executive)	$460,540	$441,495	$460,709	$458,878	$460,379	$532,425	$600,714	$771,957	$875,823
Non-Management (union and non-union)	$800,699	$700,619	$757,280	$696,441	$670,476	$666,497	$709,053	$1,004,230	$1,257,421
Total	**$1,261,239**	**$1,142,114**	**$1,217,989**	**$1,155,319**	**$1,130,855**	**$1,198,922**	**$1,309,767**	**$1,776,187**	**$2,133,244**
Total Compensation (Salary, Wages & Benefits)									
Management (including executive)	$2,761,658	$2,715,272	$2,788,777	$2,773,673	$2,954,963	$3,352,034	$3,467,790	$4,220,865	$4,684,577
Non-Management (union and non-union)	$4,314,552	$3,822,066	$4,110,112	$3,842,998	$3,723,838	$3,816,626	$4,171,926	$5,243,277	$6,593,112
Total	**$7,076,210**	**$6,537,338**	**$6,898,889**	**$6,616,671**	**$6,678,801**	**$7,168,660**	**$7,639,716**	**$9,464,142**	**$11,277,689**

4.4.3.2. Summary of FTE Changes

Table 4-48 provides the changes in FTE's by department from Milton Hydro's 2016 Test Approved to its 2023 Test Year.

Table 4-48 Summary of FTE Changes

Description	2016 OEB Approved FTE	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Historical	2022 Bridge Year	2023 Test Year	2023 Test Year vs. 2016 OEB Approved
Trades & Technical Staff										
Power Line Technician	10.0	9.0	8.5	6.2	5.1	5.0	5.2	8.0	8.0	(2.0)
Lead Hand	**4.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	**3.0**	3.0	(1.0)
Metering Technician	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	—
SCADA/OMS Technician	0.4	—	—	0.5	1.0	1.0	1.0	1.0	1.0	0.6
Engineering Technologist / Technicians	4.0	4.0	4.0	4.0	4.0	4.0	4.0	5.0	5.0	1.0
Total Trades (FTEs)	**21.4**	**19.0**	**18.5**	**16.7**	**16.1**	**16.0**	**16.2**	**20.0**	**20.0**	**(1.4)**
Trades Supervisory Staff										
Operations Supervisor	2.0	2.0	2.2	2.0	2.0	1.2	1.0	1.0	1.0	(1.0)
Operations Manager	—	—	—	—	—	—	—	1.0	1.0	1.0
Metering Supervisor	1.0	1.0	1.0	1.0	1.0	1.0	0.7	1.0	1.0	—
Engineering Supervisor	—	—	—	—	—	—	—	—	—	—
Total Trades Supervisory FTEs	**3.0**	**3.0**	**3.2**	**3.0**	**3.0**	**2.2**	**1.7**	**3.0**	**3.0**	**—**
Non-Trades & Management										
Executive	3.0	3.0	3.0	3.0	3.0	3.4	3.1	4.0	5.0	2.0
Management	7.0	7.2	6.7	7.0	7.4	7.5	7.2	10.0	10.0	3.0
Non-Union	10.1	12.3	12.2	11.5	10.8	11.2	13.6	15.7	16.7	6.6
Union	17.0	15.8	16.8	16.5	16.0	14.9	16.8	17.0	23.0	6.0
Total Trades Supervisory FTEs	**37.1**	**38.3**	**38.7**	**38.0**	**37.2**	**37.0**	**40.7**	**46.7**	**54.7**	**17.6**
Total FTE's	**61.5**	**60.3**	**60.4**	**57.7**	**56.3**	**55.2**	**58.6**	**69.7**	**77.7**	**16.2**

4.4.3.3. New & Eliminated Roles

Table 4-49 provides a summary of new roles hired and to be hired from Milton Hydro's 2016 Test Year Approved to its 2023 Test Year. For the purposes of this Table, new roles are included in the year of their start date as a full position. As such, this Table will not match precisely to Tables 4-50 to 4-57 which portray Year-Over-Year Changes in FTE's.

The addition of a new role did not necessarily result in an increase in compensation costs. Some roles as indicated in the descriptions (below) resulted in no incremental costs. Other roles were completely off set or somewhat offset by the elimination of other roles (four in total).

Table 4-49 Year-Over-Year New & Eliminated Roles

Description	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
NEW ROLES								
EXECUTIVE								
VP Customer Experience							1	
VP Corporate Services							**1**	
VP Distribution Services							1	
MANAGEMENT								
Manager People & Culture						1		
Director IT & Client Services							1	
Manager SCM							1	
Process Improvement Officer						1		
Manager Health & Safety							1	
NON-UNION/PROFESSIONAL								
Procurement Specialist					1			
Payroll Specialist						1		
Regulatory Analyst							1	
Client Services Financial Analyst							1	
IT Security & Infrastructure Specialist							1	
TRADES & TECHNICAL								
Engineering Technologist							1	
Control Room Operators								6
NEW HIRE TOTALS					**1**	**3**	**10**	**6**
ELIMINATED ROLES								
CDM Specialist				(1)				
Senior Clerk	(1)							
Director Engineering						(1)		
Director Operations		(1)						
ELIMINATED TOTALS	**(1)**	**(1)**	**—**	**(1)**	**—**	**(1)**	**—**	**—**
TOTAL NEW ROLES	**(1)**	**(1)**	**—**	**(1)**	**1**	**2**	**10**	**6**

VP Distribution Services: In 2021, Milton Hydro eliminated its Director Engineering position and replaced it as a *VP Distribution Services* position. This was accomplished with no impact to salaries and/or benefits. This position was filled in 2022 and provides leadership, oversight and broader strategic management in the areas of Operation, Engineering, and Metering. The VP Distribution Services will provide senior-level leadership and oversight, providing the right level of experience and competencies to execute Milton Hydro's Strategy 2.0, and build a cohesive workforce focused on enhancing the customer experience. The VP ensures the optimal utilization and management of the distribution network, ensuring appropriate safety and protection & controls are in place and followed. The VP Distribution Services is a key contributor in developing and achieving Milton Hydro's strategic objectives and operationalizing the execution of the objectives. The VP Distribution Services has a mandate to actively support Milton Hydro's strategic objective and to manage operations with a customer-centric mindset – encouraging and empowering all employees to focus on the customer and ensure a seamless customer approach and experience across all operational business units. The role provides technical oversight and direction with regards to the integration of digital information systems, controls, automation and technology to maximize efficiencies, performance and further enhance the customer experience.

The VP Distribution Services works closely with the Process Improvement Officer, whose role is to support and lead initiatives that result in measurable improvements to increase efficiencies and effectiveness of operational processes and performance.

VP Customer Experience: In 2022, Milton Hydro will hire a *VP Customer Experience*. As an integral part of its Executive team, this role is intended to better align the utility with the goals and objectives set forth in Milton Hydro's Strategy 2.0 – more specifically, this role will set organizational standards and expectations for customer service across all business functions – building an integrated and holistic customer-centric approach across the organization. The VP Customer Experience will guide the direction of the business in terms of customers and influence corporate activities and initiatives to ensure that the customer experience is intrinsic to all employees and their actions and decisions.

The VP Customer Experience will provide senior level leadership and oversight, better able to leverage, align, and expand Milton Hydro's service offerings, and develop a *Customer Experience Strategy*, positioning Milton Hydro as a customer-centric and responsive Company. The Strategy will set the framework to: implement initiatives and KPI's focused on continuously improving the customer experience; better understanding and responding to evolving customer needs; and making customer service intrinsic throughout the organization.

The VP will play the role of customer advocate, putting customer needs first and working to deliver value-added and solution-based services to enhance the relationship and meet customer expectations, such as technology-driven touchpoints offering customers more personalized choices, convenience and 24/7 self-serve capability.

The VP Customer Experience will strategically support the enhancement of Milton Hydro's brand through effective communications, marketing, and customer relationship management.

VP Corporate Services: In 2022, Milton Hydro will hire a *VP Corporate Services*. The new role will provide senior-level expertise and strategic oversight of multiple service functions: Regulatory Affairs, Health & Safety, People & Culture and Communications. The VP will ensure the development and delivery of aligned and efficient, people-centered, and internal client-focused services to support leaders and provide them with the expertise & tools they need to make better business decisions.

The VP Corporate Services will provide strategic expertise and oversight in the development and execution of supporting strategies that will set the framework, leading to the execution of tactical plans and KPI's aligned to the execution of Milton Hydro's Strategy 2.0.

This role will fill a current capability and strategic expertise void, and will develop and have oversight over the execution of:

- **Enhancing its H&S Program & Initiatives:** developing Milton Hydro's long-term H&S Strategy; implementing a more proactive leading indicator safety program; promoting a robust Internal Responsibility System (IRS) where every employee takes responsibility for safety in the workplace; enhanced development and utilization of a Hazard Registry and robust Incident Investigation program; and, providing oversight of Milton Hydro's first full-time safety professional (Manager H&S);

- **Strategic HR Initiatives & Support:** development of an Integrated Talent Management Strategy (employee life cycle of attraction, recruitment, retention, and development); Labour & Employee Relations Strategies & tactical plans; Performance Management & Rewards better aligned to corporate objectives & rewards; a focus on employee engagement and building a culture of customer centricity and continuous improvement; seeking process & continuous improvement through automation and innovative solutions; and positioning HR as a strategic business partner to the business, supporting business leaders with benchmarking and data to make better informed business decisions;

- **Communications & Brand Management:** providing a strategic focus on building a customer-centric and people-centred brand; enhancing internal and external communications; developing a Communications Strategy (internal and external); managing media & external stakeholder relations; supporting internal clients in developing & marketing an employment brand, safety programs, energy savings programs, etc.; and

- **Regulatory Affairs:** providing senior level expertise and experience to oversee the complex and evolving regulatory process, manage external relationships and build internal regulatory acumen through education, training and knowledge transfer with the intent to reduce the burden on the business during each COS Application process.

Manager People & Culture: Milton Hydro hired its *Manager People & Culture* in 2021 and will hire a *VP Corporate Services* to provide strategic direction and oversight in HR initiatives and practices in 2022. Prior to 2021 HR activities and practices were mostly administrative and reactive in nature, undertaken by the CEO and CFO – until 2021, Milton Hydro did not employ a dedicated HR professional. The Manager, People & Culture supports the delivery and execution of Milton Hydro’s strategic recruitment and retention strategies, leads employee and labour relations & provides coaching and advice to business leaders. The execution of strategic recruitment and retention strategies will help ensure Milton Hydro has the right level of trades & technical skills and proficiency to maintain a safe, and reliable electricity system ensuring customer reliability and responsiveness. The role will develop, train & support an enhanced Performance Management program, better aligned to corporate objectives & rewards. The role has a responsibility for employee engagement and supporting an organization-wide culture of customer-centricity and continuous improvement.

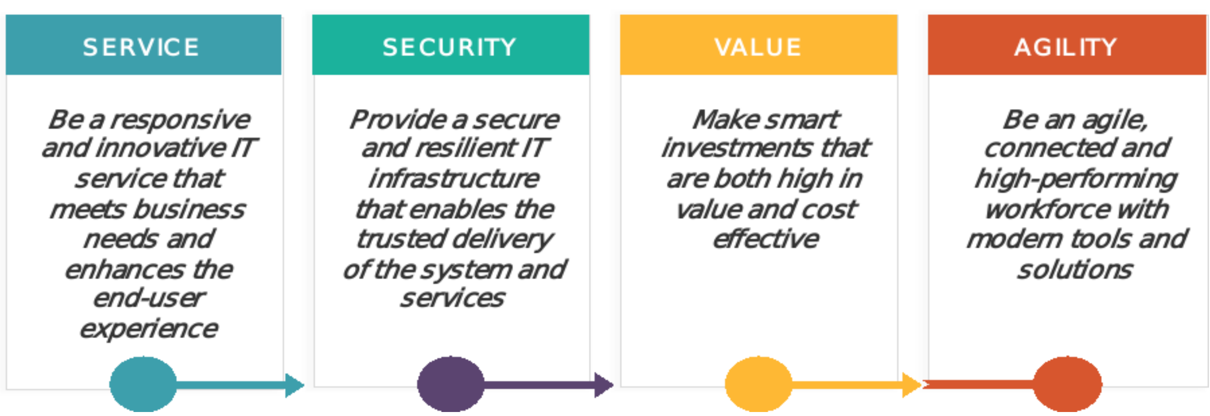
Milton Hydro’s Manager People & Culture contributes to the business as a value- added business partner and supports the organization in managing its human capital risk. The aim is to ensure operational capacity and continuity by supplying the right talent with the rights skills, within the right structure, at the right time.

Director IT & Client Services: In 2022, Milton Hydro will hire a Director IT & Client Services. The role will provide strategic expertise and oversight in; executing Milton Hydro's IT Strategy – *Optimizing Performance & Delivery.* Milton Hydro's recently developed enterprise-wide IT Strategy aligns with and supports its Milton Hydro Strategy 2.0, by: leveraging current IT technology, architecture and enterprise applications for continuous improvement in meeting or exceeding customers' needs; addressing regulatory requirements; and aligning with corporate objectives.

The role will oversee and manage the entire Information Technology function ensure the Company's technology systems are reliable, up-to-date, and enabled by automation, digitization and future-focused technology applications. This role will have an internal client-focused approach, ensuring: IT staff have the right technology skill sets; a professional and customer-oriented mindset; IT foster's and maintains valuable partnerships with business units; and, IT provides a stable, secure and highly integrated computing environment focused on ease of use for the customer and internal end users. The Director IT & Client Services will lead the IT team in establishing a supportive and collaborative culture, with a focus on enhancing the customer and employee experiences – where the IT team are given ownership and responsibility to solve internal client issues.

Milton Hydro's IT Strategic goals will align to providing the following commitments to the organization, business partners and customers.

Chart 4.14. Milton Hydro's IT Strategy Goals



<u>Manager SCM:</u> In 2022, Milton Hydro will hire a *Manager Supply Chain Management (SCM)*. This role will manage and oversee Fleet, Facilities, Stores, Procurement and SCM. The current Supervisor Procurement & Facilities role will be eliminated, and the new Procurement Specialist will report into the Manager SCM, along with 2 labourers (union) and 1 material handler (union).

The more senior level role (as compared to the Supervisor Procurement and Facilities position) will add capacity and expertise to enhance worker productivity and inventory controls by: working with vendors for 'just in time' delivery of equipment to job sites; strategic sourcing and recommendations on ergonomic and automated equipment & tools; ensuring supply chain aligns to projects and inventory demands; and monitoring and replacing equipment reaching end-of-life.

The Manager SCM will play a critical role in building Milton Hydro's procurement value chain. This role plans, organizes and evaluates procurement, facilities, stores & fleet activities including the identification of opportunities for operational improvements. The role will bring new expertise to Milton Hydro's current procurement practices by: proactively managing vendor relationships & negotiating contract terms for goods & services ensuring best value for the organization; and, developing and managing the bid and Request for Proposal ("RFP")/Tender process through to recommendation & selection.

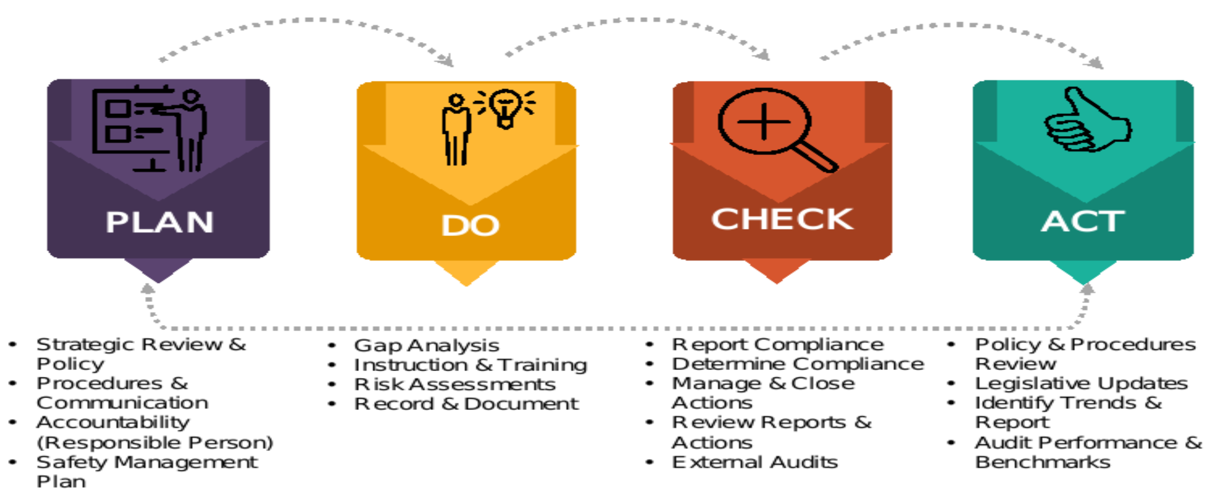
<u>Process Improvement Officer:</u> In early 2022, the *Process Improvement Officer* (PIO) was hired. This role brings a new discipline to Milton Hydro. This role will assist Milton Hydro in refining systems and processes and enabling employees to use their time wisely (value-added) and avoid repetitive or tedious tasks. The PIO through better resource and technology utilization – will increase productivity and morale, mitigating employee turnover and enhancing employee engagement.

The PIO will report directly to the CEO, and therefore have broad scope and authority across the organization. The role requires Lean Six Sigma certification and brings expertise in Six Sigma diagnostic methodologies to identify and make: incremental improvements; step change improvements; and transformational improvements. As well as playing a role achieving the objectives of Milton Hydro's Strategy 2.0, this role will support the execution and deliverables within Milton Hydro's 2021 IT Strategy (*Optimizing our Performance & Delivery)* – such as, Milton Hydro's Business Process Automation and Enterprise Resource Planning (ERP) technology solutions planned to launch in 2024.

For additional details on how the role will benefit Milton Hydro, refer to Section 4.4.2.6.

Manager Health & Safety: Since 2016 Milton Hydro has engaged a contracted employee, to oversee and manage its Safety initiatives, The contractor provides services to Milton Hydro in this function on average three (3) days per week. In 2022, Milton Hydro will hire its first dedicated in-house Manager H&S, eliminating the cost of contracting out, resulting in a slight net savings to Milton Hydro Customers. The new Manager H&S will develop, execute and manage Milton Hydro's first *H&S Strategy* and tactical plans, and: implement a proactive leading indicator safety program; promote a robust Internal Responsibility System (IRS) where every employee takes responsibility for safety in the workplace; enhance the development and utilization of its Hazard Registry and robust Incident Investigation program; and ensure compliance with all regulatory and legislative requirements. The role will provide support to the Operations group in developing work methods & standards, managing contractor safety, and enhancing crews visits and internal audit processes. The Manager H&S will work with the organization, to adapt is programs, policies and procedures in line with the Plan, Do, Check, Act (PDCA) approach. The PDCA is a simplistic and effective process to use when implementing risk controls through corrective and preventative actions.

Enhancing and improving IRS, safety oversight and management of safety will help reduce safety incidents, enhance safety performance, resulting in overall cost efficiencies for customers.



Procurement Specialist: This position will report directly to the Manager SCM (when hired in 2022). This Procurement Specialist position is responsible for: providing various procurement services and the co-ordination of inventory and stock; and, for collaborating with the business functions as an internal client-services provider. Under the direction of the new Manager SCM the Procurement Specialist will evaluate procurement business processes in order to create new efficiencies and implement best practices using software tools and web enabled platforms. The role will further be responsible to: develop and present procurement training and orientation programs for management; keep business partners updated on procurement initiatives and projects; provide system maintenance, training and testing as required; analyze data and develop reports for more informed decision-making; and, recommend up-to-date procurement best practices related to Milton Hydro's policies and procedures.

Payroll Specialist: In 2021, Milton Hydro hired a Payroll Special. Prior to this hire, payroll was part of the Financial Analyst role, and is primarily a manual process. Prior to hiring this role, there was no backup support which posed a critical single incumbent risk. In 2021, the new SMT recognized the potential risk of not having specialized payroll expertise managing payroll and not utilizing a payroll software system to mitigate manual human errors. The Payroll Specialist and the Manager People & Culture undertook an RFP and selection process in 2021 and awarded ADP Payroll as its new integrated HRIS/Payroll system. Milton Hydro anticipates this system to be fully implemented in Q1 2022. The Payroll Specialist will manage ADP's payroll software ensuring: accurate and timely completion of payroll for both the union and non-unionized workforce. The role is responsible for preparing all required remittances, management reports and analysis as required. The Payroll Specialist will assist business unit leaders in preparing annual labour and resource budgets, aligned to workforce planning initiatives.

Regulatory Specialist: In 2021 Milton Hydro created a new Regulatory Specialist position to provide support for its regulatory filing and procedural requirements and filled this vacancy with a contract employee. In 2022 Milton Hydro hired a full-time permanent *Regulatory Specialist* fully dedicated to Regulatory Affairs. Previously Milton Hydro allocated 1/2 of an FTE to perform Regulatory Analytical work. The 1/2 FTE role also provided financial analysis support to the Finance department. The decision to make the role permanent is in part due to, market difficulty in finding qualified Regulatory Analysts, either on a temporary or permanent basis. The skill and expertise are very specific to the utility sector, and regulatory expertise is becoming harder to recruit.

The Regulatory Specialist will be a subject matter expert resource to the Customer Service Department regarding all aspects of how customer bills are calculated, and the amounts billed to each customer classification. This will help customer service staff be more knowledgeable of billing calculations, so their knowledge and skills are increased to deal with customer queries, and therefore more helpful and responsive to customers. This role will provide analytical support to the Director, Regulatory Affairs and help answer questions from customer groups regarding Milton Hydro's annual rate applications.

This role will be involved in the implementation/testing of new rates set up in the customer information system (CIS) to ensure accuracy of new rates in the system. Currently only the Billing Supervisor is involved in testing the rates set up in the CIS. Regulatory Affairs needs to be involved in supporting the set-up of new rates, and confirmation of testing.

This role will support the Communications Department to achieve its goal of being customer centric and provide information in order that accurate and adequate quantitative and qualitative information can be incorporated into the messaging of communications materials provided to customers. This role will also support other departments as needed as a SME to help them achieve their goals.

This role will work with the Director, Regulatory Affairs and Process Improvement Officer to improve department efficiencies, such as: updating and improving the processes of the Regulatory Affairs Department which has become a patchwork of disjointed processes with multiple sources of data and analysis being required.

Client Services Financial Analyst: Aligned to Milton Hydro's Strategy 2.0, building an organizational customer-centric mindset includes an internal client-focused approach to providing services and support. In 2021, Milton Hydro's Financial Analyst's role and scope changed to include this focus. Milton Hydro will hire an additional *Client Services Financial Analyst* in 2023. The Analysts will work with operational partners assisting them in: setting budgets; quarterly forecasting; managing to budget; budget allocations; and financial reporting. Milton Hydro believes this partnering role will enhance mid-level leaders financial and business acumen over time and provide them with a better understanding of the business, when developing and managing budgets. Reporting to the Controller, the Analysts are also responsible for assisting in the preparation of monthly, quarterly and annual reporting. The Analysts also prepare and maintain regular analysis of major revenue and expense accounts, reconcile the general ledger accounts, and prepare journal entries consistent accounting principles.

IT Security & Infrastructure Specialist: In 2022, this position will be hired to focus on the security and ongoing protection of Milton Hydro's assets and data, including its customers' billing and payment information. The role is specifically responsible for the deployment of the Ontario Cyber Security Framework as part of Milton Hydro's comprehensive cyber security protection program, and to ensure it follows industry best practices in its efforts to protect and secure its assets. This role is also responsible for the overall health and maintenance of all IT infrastructure requirements. Currently these responsibilities are partly shared by the Supervisor IT, Network Administrator and Systems Analyst. Milton Hydro has no dedicated resource with the right level of IT security expertise and experience.

The Specialist is required to recommend and implement appropriate security controls to protect the Company's information system assets from unauthorized access and compromise/loss and to mitigate cyber related risks. This includes performing regularly scheduled Vulnerability Assessments, recommending, and implementing effective monitoring, establishing control measure baselines for subsequent effectivity assessment, and tracking KPI based cyber security metrics for reporting purposes.

Engineering Technologist: In 2022, Milton Hydro will increase its *Engineering Technologist* complement by one. The work is currently out-sourced, in-sourcing will deal with the influx of work primarily resulting from: continued customer growth; and design & inspection work requirements due to in-sourcing additional capital and maintenance work. Engineering Technologists prepare, design and audit construction projects for both overhead & underground plant and customer connections. The new role will ensure Milton Hydro can continue to satisfy the requirements of the Distribution System Code (DSC). The steady increase in volume and complexity of requests for customer connections over the past years has increased the amount of time a customer has to wait for an offer to connect (OTC). Customers are currently waiting as much as 60 days for an OTC. As the volume of requests continue to increase, Milton Hydro risks not being able to satisfy the DSC requirement sub-section 6.1.1. relating to customer's requests for connection.

The new role will allow for more time to be allocated to each project. The additional time is expected to improve the attention to detail required at the design stage, communication with the field staff and minimize the risk of changes required at the time of construction.

<u>Control Room Operators:</u> By the end of 2022, Milton Hydro plans to have its control room operations and equipment functional. As such, it will hire six (6) *Control Room Operators* to support the business function. Control Room Operators monitor the SCADA and Outage Management systems in order to proactively and reactively respond to outage, reliability and power quality events. Reference Exhibit 4 sub-section 4.4.2.4. Network Control Room Operations, the DSP and Exhibit 2. The Operators will be dedicated to operating Milton Hydro's distribution network. Their attention will focus solely on one electricity distribution system which enables them to quickly respond to planned or unplanned events and confidently work with line crews. The Operators will be fully involved with the daily operation and capital activities. With this in-depth in-house knowledge of the distribution system and the ability to focus, means they can readily provide information to engage with customers during outage events. They would be able to respond quickly to restoring power outages which in turn, will improve system and customer reliability.

Maintaining in-house dedicated Operators means they would help in operational planning. They would be able to work on the long-term goal of continuing system optimization to improve system operation efficiency, less outage time for customers, improve system losses, continue to improve ways to respond to system events and provide a better customer experience.

With more attention on continuing efficiency, the productivity of engineering and operations would also improve as there would be fewer revisions during the project cycle since learned lessons would be fed back into the continual improvement cycle. For example, a job gets delayed because of a design issue or lack of thorough review and could cost many thousands of dollars as it impacts everyone's planning, from contractors to internal operations resources, which would have a cascading effect to other projects.

4.4.3.4. Eliminated Positions

<u>CDM Specialist:</u> The CDM role was eliminated due to the wind down of the Conservation First Framework eliminating the CDM programs. The employee has moved on to work with a third-party and is assisting us on a limited basis until such time the remaining few projects are complete.

<u>Senior Clerk:</u> After the departure of the Senior Clerk, responsibilities were re-aligned and a decision was made to eliminate the position.

Director Operations: The individual in the position/role retired at the end of 2016, and the position was eliminated in 2017.

Director Engineering: The individual in the role was terminated in 2021. Milton Hydro made the decision to eliminate this role and replace it with a VP Distribution Services. This change resulted in a reduction to salaries and/or benefits to mitigate the reductions assumed in the 2016 decision.

4.4.3.5. Year-Over-Year Changes in Headcount

In the following section, Milton Hydro details its year-over-year changes in FTE's and provides an explanation for both reductions and additions of FTE impacts within each year's totals.

Table 4-50 2016 Actual to 2016 OEB Approved

2016 OEB Approved	2016 Actual	2016 Actual vs. 2016 OEB Approved	New Hires	Outsourced	Eliminated Positions	Vacancies	Temporary Fill	Students
61.6	60.2	(1.4)	0.0	(2.0)	(1.0)	(0.4)	(1.0)	3.0

Reduction of 1.4 FTE's primarily related to: (i) previous management's decision to outsource additional PLT and the elimination of a Lead Hand as a result of outsourcing (-2.0); (ii) elimination of a Sr. Clerk in Customer Services (-1.0); (iii) reduction of a temporary Communication Coordinator (-1.0); (iv) vacancy related to the retirement of the Director Engineering (-0.4). Reductions were partially offset by: (v) increased students hired (+1.5) and (vi) higher Customer service resources to support billing and call centre operations (+1.5).

Table 4-51 2017 Actual to 2016 Actual

2016 Actual	2017 Actual	2017 Actual vs. 2016 Actual	New Hires	Outsourced	Eliminated Positions	Vacancies	Temporary Fill	Students
60.2	60.4	0.2	—	—	—	—	—	—

FTE's remain consistent year-over-year. Nominal (+0.2) increase related to rounding.

Table 4-52 2018 Actual to 2017 Actual

2017 Actual	2018 Actual	2018 Actual vs. 2017 Actual	New Hires	Outsourced	Eliminated Positions	Vacancies	Temporary Fill	Students
60.4	57.9	(2.5)	—	(2.3)	—	—	—	—

Reduction of 2.5 FTE’s primarily related to fewer PLT’s as a result of further outsourcing construction work to 3rd party contractors (-2.3). The 0.2 difference relates to crossover hires and predecessors staying to train, plus a minor offset with lower student complement.

Table 4-53 2019 Actual to 2018 Actual

2018 Actual	2019 Actual	2019 Actual vs. 2018 Actual	New Hires	Outsourced	Eliminated Positions	Vacancies	Temporary Fill	Students
57.9	56.3	(1.6)	—	(1.8)	0.2	—	—	—

Reduction of 1.6 FTE’s primarily related to: (i) fewer PLT’s as a result of further outsourcing (-1.2); and (ii) the elimination of the CDM Specialist role (-.4).

Table 4-54 2020 Actual to 2019 Actual

2019 Actual	2020 Actual	2020 Actual vs. 2019 Actual	New Hires	Outsourced	Eliminated Positions	Vacancies	Temporary Fill	Students
56.3	55.3	(1.0)	1.0	—	—	(1.7)	—	(0.3)

Reduction of 1.0 FTE’s primarily related to: (i) vacancy due to Sr. Clerk on STD (-1.1); (ii) vacancy Supervisor Operations role (-0.6); and (iii) lower student complement (-0.3); primarily offset by: (iv) addition of a Payroll Specialist (+0.3); (v) hiring a new Chief Executive Officer (+0.4); and (vi) hiring a new Director Regulatory (+0.4). In 2020, the CEO, Director, Regulatory Affairs, and Payroll Specialist positions included overlap of the predecessor and incumbent.

Table 4-55 2021 Historical to 2020 Actual

2020 Actual	2021 Actual	2021 Actual vs. 2020 Actual	New Hires	Outsourced	Eliminated Positions	Vacancies	Temporary Fill	Students
55.3	58.5	3.2	2.0	—	—	(1.7)	2.9	—

Addition of 3.2 FTE’s primarily related to: (i) temporary hire of a Clerk to support Finance and Customer Service due to increased requirements to support Operations and back-fill for a short-term disability (STD) (+1.8); (ii) hiring a new Payroll Specialist (+0.9); (iii) hiring Communications Coordinator (+0.6); (iv) hiring a Procurement Specialist (+0.5); (v) temporary Regulatory Specialist role (+0.5); and (vi) addition of a temporary control room operator (0.6); primarily offset by: (vii) vacancy of Director Regulatory (-0.3); (viii) vacancy CEO (-0.4); (ix) vacancy due to termination of General Labourer (-0.6); and, (x) a vacancy due to retirement of the Supervisor

Metering (-0.4). In 2020, the CEO and Director, Regulatory Affairs positions included overlap of the predecessor and incumbent.

Table 4-56 2022 Bridge Year to 2021 Actual

2021 Actual	2022 Bridge Year	2022 Bridge Year vs. 2021 Actual	New Hires	Outsourced	Eliminated Positions	Vacancies
58.5	69.7	11.2	6.9	3.3	—	1.0

Addition of 11.2 FTE's primarily related to: (i) additional PLT's due to in-sourcing of contractor work previously done by 3rd party contractors (+2.8); (ii) hiring of VP Customer Experience (+0.5) and VP Corporate Services (+0.5); (iii) hiring Engineering Technologist (+1.0); (iv) hiring Manager SCM (+1.0); (v) hiring Client Services Financial Analyst (+1.0); (vi) filling vacancy of Operations Supervisor role (+1.0); (vii) hiring Process Improvement Officer (+1.0); (viii) hiring Director IT & Client Services (+1.0); (ix) temporary Regulatory Analyst to support backfilling in support of COS Application (+0.5); and (x) additional student support in Customer Service and Network Operations (+0.9).

Table 4-57 2023 Test Year to 2022 Bridge Year

2022 Bridge Year	2023 Test Year	2023 Test Year vs. 2022 Bridge Year	New Hires	Outsourced	Eliminated Positions	Vacancies	Temporary Fill	Students
69.7	77.7	8.0	8.0	—	—	—	—	—

Addition of 8.0 FTE's primarily related to: (i) hiring Control Room Operators to provide 24/7 control room services (+6.0); (ii) hiring of IT Infrastructure & Security Specialist (+1.0); and (iii) hiring (full-year impact) of VP Customer Experience (+0.5) and VP Corporate Services (+0.5).

4.4.4. Compensation

4.4.4.1. Introduction

Under the leadership of its new executive, Milton Hydro is in the process of developing its compensation philosophy premised on: its ability to attract, retain and motivate a highly-skilled workforce; offering a competitive market-driven total compensation package; and on driving a results and performance-driven culture. This is achieved by appropriately and equitably rewarding performance in the achievement of objectives aligned to Milton's Hydro' strategic objectives. This also includes remaining competitive, yet prudent in the negotiations of its

Collective Agreement and offering an LDC comparable incentive opportunity for its management and non-union/professional groups.

To support and execute this philosophy, in 2022 Milton Hydro will review each management and non-union role, against the Korn Ferry (formerly Hay Group) Job Evaluation ("JE") methodology. Each position will be assigned JE points evaluation against: know-how; problem-solving responsibilities; accountability; and working conditions. Assessing working conditions ensures JE's are compliant with Pay Equity. Once the JE's are developed, Job Descriptions will be updated for each position in the management and non-union groups. JE points are integral to developing and maintaining a robust and sustainable Salary Structure, as they direct where each role falls within the Structure, into which Grade and amongst grouping of roles with similar points.

Once each role has been assigned a JE point, the consultant will review, and make recommendations on the redesign of Milton Hydro's current Salary Structure and undertake a total compensation market-competitive review. The new Salary Structure will include methodically defined JE point spreads between grades and realize reasonable pay grade differentials to maintain: internal equity; reasonable compression between reporting relationships; and a spread for additional scope and accountability between grades.

The total compensation market review will be based on current data, and may include:

- Korn Ferry market data for both Broader Public Sector and Industrial (excluding the GTA).
- Comparator data will be based on P50 market position[6].
- LDC specific comparator roles against Milton Hydro's peer LDC and whom it either loses or attracts talent.
- MEARIE Management Survey (most recent Report).

The results of the compensation review will be overlaid into Milton Hydro's redesigned Salary Structure. Milton Hydro will consider the impact of individual employees' compa-ratio's (actual

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[6] P50 refers to 50th percentile data.

salary divided into the job rate for the salary grade), and determine a reasonable course of action, particularly for any individuals whose compa-ratio exceed 100% of job rate.

Further in 2022, as part of its continuous improvement efforts, Milton Hydro intends to enhance, and add more rigour and discipline to its Performance Management Program and practices. The enhancements will include: revising, training & utilizing performance management evaluations and tools for both merit and incentive pay opportunity; putting more rigour in setting, measuring and assessing results of objectives tied to incentive pay; and training and supporting leaders in providing effective and value-add performance evaluations for all employees.

Milton Hydro's new program is expected to dictate and direct that both corporate and individual objectives tied to incentive, are based on a Balanced Scorecard (BSC) approach, and weighted relative to strategic and operational priorities and results. The roll-out and training on the enhanced incentive program and objectives, will be: based on setting and evaluation utilizing the S.M.A.R.T. methodology (Specific, Measurable, Achievable, Relevant and Timebound); establishing 'stretch' objectives; and objectives should be over and above activities considered part of an employee's day-to-day job.

4.4.4.2. Management & Non-union Professional Total Compensation

Milton Hydro provides its management and non-union/professionals a total compensation package comprised of: base salary based on merit increases, and an incentive pay opportunity. Incentive pay is considered an 'opportunity' as eligible employees can earn up to a pre-defined percentage of incentive pay, the percentage is based on their current annual salary. Incentive pay is not guaranteed, does not compound annual salary and is re-earnable year-over-year. Objectives aligned with incentive pay, should be considered 'stretch' and have a direct impact on achieving the Company's strategic objectives.

4.4.4.2.1 Incentive Pay

Table 4-58 provides the actual average incentive pay per management and non-union/ professional employee from 2016 to 2021.

Table 4-58 Average Incentive Pay per Employee

Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Historical	2022 Bridge Year	2023 Bridge Year
Number of Employees (FTEs including Part-Time)[1]									
FTEs	17	17	17	17	18	18	17	22	24
Total Incentive Amount	$244,916	$244,916	$227,530	$250,816	$330,226	$314,419	$419,393	$505,271	$587,788
Average Incentive Amount	$14,407	$14,407	$13,384	$14,754	$18,346	$17,468	$24,670	$22,967	$24,491

In 2011 Milton Hydro's Board of Directors approved a two-phase incentive program. The Phase One Incentive plan is applicable to all non-union and management staff and is based on Milton Hydro's Occupation Health and Safety Management system (OH&S), OEB service indicators, personal performance, and extra-ordinary events. The Phase Two Incentive plan is applicable to the senior management team, inclusive of Directors and above, and is based on financial targets of OM&A and Capital, OEB customers/employee, and customer/community outreach.

Non-union and management staff receives an incentive pay after the annual audit has been completed. To date, these payments have been based on financial performance, safety achievements, customer service surveys, implementation of cost saving initiatives and completion of work programs that are incremental to normal operations but important for the business to achieve its corporate objectives.

4.4.4.2.2 Merit Pay

Merit Pay is the portion of total compensation that is added to an individual's base salary. Merit Pay rewards individuals for the growth, commitment, drive, and achievement in the performance of their role in the organization. Job rate (100%) is the rate at which a fully experienced and competent individual achieves or is expected to operate at. Below Job Rate, the individual is either new to the role and/or considered to be developing.

The Compensation/HR Committee of the Board of Directors annually approves pay increases for management and non-union professionals, on the recommendation of the CEO. Currently, merit pay recommendations are based on a progression adjustment within the salary grade based on performance. Salary grades were originally developed by the Compensation/Human Resources Committee in 2011, utilizing as its market source, the annual MEARIE Management Salary Survey.

4.4.4.2. *Annual Salary Band Increases*

Table 4-59 below provides the year-over-year increases to job rates. Through this period, shifts were based primarily on: comparability to Milton Hydro's negotiated union contract annual increases, and adjusted for inflation.

Table 4-59 Management & Non-Union Professional Salary Band Increases

Performance Year	% Shift
2016	3.0%
2017	2.8%
2018	2.6%
2019	2.6%
2020	2.5%
2021	2.4%

As part of its 'new' Performance Management program to be developed in 2022 (Section 4.4.4.1) and as part of its evolving recruitment and retention strategies, Milton Hydro is committed to ensuring employees are paid at the 50th percentile and at market competitive rates. It is common for job rates to have a percentage shift annually, at the beginning of a new performance year. Milton Hydro's shift is reviewed annually, and the decision to increase job rate will be: reflective of current market conditions; inflation rates; geographic conditions; and union increases outlined in the collective bargaining agreement. Milton Hydro engages its network of LDC peers and share projected percentage increases to their respective Salary Bands, as part of its consideration. It also considered the annual MEARIE Management Salary Survey historical and projected data. A shift in job rate should not equate to the same percentage shift for individual employees. Merit increases are based on individual performance and development over the performance year and will fluctuate for each individual employee.

4.4.4.3. *Union Wages*

Milton Hydro's collective agreement with unionized staff provides for annual increases and employee step progressions. Labour rates and benefits are adjusted annually based on negotiated percentages in accordance with the collective agreement. The wages for unionized employees are negotiated through the collective bargaining process and include both office and trade workers represented by the *Power Workers' Union, Local 1000* of the Canadian Union of Public Employees.

Milton Hydro’s current collective agreement expires on December 31, 2023. Wages and benefits are a result of a collaborative negotiated process, based on factors such as recent settlements in the LDC sector, including neighbouring LDC’s.

Each job classification at Milton Hydro has a wage rate progression scale that increases from a base rate to a maximum rate. Milton Hydro utilizes the industry standard Hay Point system to evaluate positions and to develop pay structures. A joint management/union team uses a defined process to determine overall job rating.

Table 4-60 below provides the annual union employee increases as negotiated as part of the Collective Agreement.

Table 4-60 Union Wage Increases

Contract Year	Negotiated %
2016	2.4%
2017	2.0%
2018	2.0%
2019	2.1%
2020	2.2%
2021	2.0%
2022	2.0%
2023	2.1%

4.4.5. Benefit Program Costs

Milton Hydro offers a comprehensive and competitive benefits package which include health & dental, life insurance, vacation & leave policies, Employer Health Tax, CPP, EI contributions and WSIB insurance. The plans are designed to address the health and wellness needs of all of Milton Hydro’s employees.

Benefit plans for each employee group are essentially the same. The unionized benefits plan, negotiated through the collective bargaining process, is the result of a collaborative and negotiated process, based on factors such as recent settlements in the LDC sector, and Milton Hydro’s neighbouring LDC peer groups. The following table provides a detailed summary of all Milton Hydro paid statutory and fringe benefit program costs from 2016 OEB Approved to the 2023 Test Year.

Table 4-61 Benefit and Pension Costs

Description	OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Historical	Bridge Year	2023 Test Year
Statutory									
CPP	$157,049	$144,893	$151,244	$153,419	$148,234	$158,678	$172,252	$230,623	$278,640
EI-Employer's Portion	$71,065	$68,142	$59,772	$62,685	$56,918	$58,325	$116,250	$84,939	$98,711
Employer's Health Tax	$111,130	$103,949	$109,436	$104,722	$105,487	$113,739	$116,250	$145,324	$176,740
WSIB Premium Expenses	$50,751	$46,400	$47,809	$48,481	$46,902	$39,643	$41,479	$52,911	$61,369
Total Statutory	**$389,995**	**$363,384**	**$368,261**	**$369,307**	**$357,541**	**$370,385**	**$446,231**	**$513,797**	**$615,460**
Active									
Omers	$558,964	$478,829	$498,654	$474,334	$482,689	$519,574	$597,242	$794,714	$951,466
LTD Insurance	$53,053	$47,310	$55,147	$47,003	$41,686	$41,741	$44,254	$75,939	$80,199
Life Insurance	$24,417	$40,378	$43,339	$31,653	$23,723	$24,095	$28,648	$41,444	$49,634
Health Benefits (Health & Dental)	$234,810	$212,213	$252,587	$233,022	$225,246	$243,127	$257,046	$350,293	$436,485
Total Active	**$871,244**	**$778,730**	**$849,727**	**$786,012**	**$773,344**	**$828,537**	**$927,190**	**$1,262,390**	**$1,517,784**
Grand Total	**$1,261,239**	**$1,142,114**	**$1,217,988**	**$1,155,319**	**$1,130,885**	**$1,198,922**	**$1,373,421**	**$1,776,187**	**$2,133,244**
Employee Future Benefits	$15,735	$17,650	$25,702	$17,757	$18,391	$32,010	$43,885	$20,000	$20,400
Grand Total Including Future Benefits	**$1,276,974**	**$1,159,764**	**$1,243,690**	**$1,173,076**	**$1,149,276**	**$1,230,932**	**$1,417,306**	**$1,796,180**	**$2,153,644**

4.4.5.1. OMERS Pension Plan

Milton Hydro employees are members of the Ontario Municipal Employees Retirement System (OMERS). OMERS is a multi-employer pension plan that most LDCs participate in, therefore the pension benefit provided to Milton Hydro employees is consistent with that of other LDCs. The plan is a contributory defined pension plan which is financed by equal contributions from the employer and employee based on the employee's contributory earnings. Milton Hydro's pension premium information for 2016 OEB Approved to 2023 Test Year is provided in Table 4-61 above. For the 2023 Test Year, Milton Hydro assumed OMERS rates of 9.0% on earnings up to CPP earning limits and 14.6% on earnings over CPP earnings limit as published on the OMERS website. The rates for the 2023 Test Year use inflation relative to the assumptions for wage increases outlined in Tables 4-59 and 4-60 above.

<u>Variance Analysis</u>

Benefits and pension costs year-over-year changes for the period 2016 Actual to 2023 Test Year are primarily related to: fluctuations in FTEs related to timing of hires, vacancies, and the changes to outsourcing trades work to third parties; the increase in the Canada Pension Plan ("CPP") costs related to the enhanced program introduced in 2019; the higher experiences relating to medical and dental resulting in higher employer paid premiums, and general annual wage inflation.

Post-Retirement Benefits

Milton Hydro provides a post-employment benefit life insurance plan to all active full-time and retired employees.

Post-employment benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method prorated on service and based on assumptions that reflect Management's best estimates. Under this method, the projected post-retirement benefit is deemed to be earned on a pro rata basis over the years of service in the attribution period commencing at the date of hire and ending at the earliest age the employee could retire and qualify for benefits. The current service cost for the period is equal to the actuarial present value of benefits attributed to the employees' services rendered in the period. Past service costs from the plan amendments are amortized on a straight-line basis over the average remaining service period of the employees' active at the date of amendment.

RSM Canada Consulting LP performed the actuarial valuation of the post-retirement non-pension benefits sponsored by Milton Hydro to determine the accounting results for those benefits for the fiscal periods ending December 31, 2020, and December 31, 2021, respectively. The initial report prepared for December 31, 2020, incorporated a complete review of employee demographics and assumptions while the report for December 31, 2021 incorporated changes to the discount rate and extrapolations of actual benefit payments liability and expense figures from the prior year. Milton Hydro's pension benefits are identified as defined benefit plans.

The 2020 and 2021 reports from RSM Canada Consulting LP are provided in Attachment 4-4 and Attachment 4-5 of this Exhibit. Changes to other benefits offered by Milton Hydro to its employees are limited to inflation and increases/ decreases in the number of FTE's. Milton Hydro annually reviews its benefit plan relative to the market to ensure it has secured a competitive rate to support the structure of our benefit obligations to eligible current and retired employees.

The report is prepared in accordance with the International Financial Reporting Standards (IFRS) guidelines, specifically International Accounting Standards 19 (IAS) Employee Benefits.

The table below provides the realized and expected present value of Defined Benefit Obligations for 2016 OEB Approved to 2023 Test Year.

Table 4-62 Post-Retirement Benefits Liability

Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Historical	2022 Bridge Year	2023 Test Year
Defined benefit obligation, opening balance	$304,086	$304,086	$319,821	$482,392	$496,556	$509,917	$669,800	$617,644	$638,337
Current service cost	$12,119	$12,119	$12,623	$12,337	$11,837	$11,500	$24,084	$19,917	$20,535
Interest cost	$12,290	$12,290	$13,079	$16,625	$17,107	$17,800	$16,710	$18,866	$19,506
Acturial losses	$—		$138,500		$—	$133,500	($90,148)	$—	$—
Benefits paid	($8,674)	($8,674)	($1,631)	($14,798)	($15,583)	($2,917)	($2,802)	($18,090)	($18,166)
Net Liability / Asset	$319,821	$319,821	$482,392	$496,556	**$509,917**	**$669,800**	**$617,644**	**$638,337**	**$660,212**

Milton Hydro's pension and Other Post employment benefit ("OPEB") costs are recovered using the default accrual method.

4.5. Shared Services/Corporate Cost Allocation

Milton Hydro has a business relationship with Milton Hydro Holdings Inc. ("Holdings") and Milton Energy Generation Services ("MEGS") both are affiliated companies. These relationships are for either the purchase of or provision of products and services and are in place to benefit from cost savings due to increased efficiencies and economies of scale. A summary of the transactions and pricing methodology used to assign costs for 2016-2021 Actual and projections for the 2022 Bridge Year and 2023 Test Year, is provided in the following Table 4-63 to Table 4-70 A in the format of the OEB Appendices 2-N.

4.5.1. Shared Services

Consistent with the *Affiliate Relationships Code for Electricity Distributors and Transmitters,* the pricing methodology used for shared services is based on fully allocated costs. The time devoted to providing the services is based on an average estimated time spent by Milton Hydro staff on providing the services to Holdings and MEGS. All amounts billed to the affiliates are excluded from Milton Hydro's OM&A.

4.5.2. Milton Hydro Holdings Inc. ("Holdings")

Holdings' Board of Directors meets every two months or as required. Holdings has no employees and charges each of its active affiliates a management fee based on a current estimate of the Board's resource utilization. The management fee is reviewed annually and covers the expenditures of the Board and expenses of Holdings. Currently the Board's resource utilization is allocated 90% to Milton Hydro Distribution and 10% to MEGS.

No mark-up is applied to Holdings costs which consist primarily of Holdings Directors fees, meeting expenses, management services, administration, legal, audit and insurance expenses.

4.5.3. Milton Hydro Distribution Inc.

Milton Hydro Distribution Inc. provides services to both Holdings and MEGS for administrative services, accounting and finance, corporate support, banking services and management. These services are described as follows:

4.5.4. Services Provided to Affiliates by MHDI

4.5.4.1. Accounting (MHDI provides to MEGS and Holdings)

MHDI performs accounting services for both MEGS and Holdings. These costs are recovered on a fixed basis throughout the year. At year-end the actual cost is determined using actual time spent and the fully allocated cost per hour. Any cost differential between the actual and the fixed charges are trued-up between MHDI, MEGS and Holdings on an annual basis.

4.5.4.2. Water/Waste-Water Billing (MHDI provides to MEGS)

Water/Waste-Water billing services are directly allocated to MEGS from MHDI based on the actual fully burdened costs to perform this service. These costs include:

- shared billing clerk (bill preparation and presentment);
- shared customer service representative (payment processing, collections, bad debt management and customer care); and
- shared Customer Information system.

Milton Hydro provides water billing, customer service and collection services to MEGS who in turn has contracted with the Region of Halton ("Region") for provision of these services. MEGS is responsible for contracting the reading of the water meters. As Milton Hydro is not directly associated with the Region and considers the MEGS contract with the Region to be a commercial activity Milton Hydro charges MEGS a Basic Service Charge, invoiced, and calculated on fully allocated costs. The revenue derived from water billing is based on the actual water meters billed by Milton Hydro. The revenue for the provision of this activity is recorded as a revenue offset in USoA 4390. Water billing costs and revenues increase in the 2016-2023 period due primarily due to an increase in the number of customers and inflation.

4.5.4.3. Sentinel lights (MHDI to MEGS)

Milton Hydro provides for the billing of sentinel light rentals on behalf of MEGS on a fully allocated costs basis. Milton Hydro also manages the repairs and maintenance of sentinel lights on behalf of MEGS. As of 2019, repair work has been outsourced to Ducon Utilities. Incoming call for repairs of sentinel lights are received by Milton Hydro and routed to Ducon for repairs. Ducon repairs are paid directly by MEGS. Milton Hydro will occasionally perform a repair on behalf of MEGS and records the services provided for sentinel light maintenance on recoverable work orders and bills MEGS at actual cost-based prices.

4.5.4.4. General services

In addition, Milton Hydro also performs routine administrative services on MEGS assets, namely the Co-gen unit located at the Milton Sports arena and the four (4) FIT solar units in Milton located at the following addresses:

- 200 Chisholm Drive
- 605 Santa Maria Blvd
- 217 Laurier Avenue
- 1010 Main Street East

MHDI will source, negotiate, and renew maintenance and repair contracts for these assets. Costs of these contract are paid directly by MEGS.

The following section provides details of shared services from 2016 to 2023. Information provided is OEB Appendix 2-N.

Table 4-63 Appendix 2-N - 2016 Actual

Shared Services					
Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Administration Fee	Cost Based	$16,116	$16,116
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Admin Staff	Cost Based	$3,947	$3,947
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Administration Fee	Cost Based	$444	$444
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Admin Staff	Cost Based	$6,369	$6,369
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Billing Sentinel Rentals	Cost Based	$3,828	$3,828
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Sentinel Light Maintenance	Cost Based	$8,325	$8,325
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Water Billing	Cost Based	$606,250	$606,250
Corporate Cost Allocation					
Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Milton Hydro Holdings Inc.	*Milton Hydro Distribution Inc.*	Management Fee	Cost Based	98.0%	$21,480

Table 4-64 Appendix 2-N - 2017 Actual

Shared Services					
Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Administration Fee	Cost Based	$50,856	$50,856
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Admin Staff	Cost Based	$5,855	$5,855
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Administration Fee	Cost Based	$49,344	$49,344
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Admin Staff	Cost Based	$13,067	$13,067
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Billing Sentinel Rentals	Cost Based	$3,828	$3,828
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Sentinel Light Maintenance	Cost Based	$12,774	$12,774
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Water Billing	Cost Based	$636,101	$636,101
Corporate Cost Allocation					
Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Milton Hydro Holdings Inc.	*Milton Hydro Distribution Inc.*	Management Fee	Cost Based	98.0%	$22,833

2017 shared service levels are consistent with 2016.

Table 4-65 Appendix 2-N - 2018 Actual

Shared Services					
Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Administration Fee	Cost Based	$50,856	$50,856
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Admin Staff	Cost Based	$4,992	$4,992
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Administration Fee	Cost Based	$60,344	$60,344
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Admin Staff	Cost Based	$4,769	$4,769
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Billing Sentinel Rentals	Cost Based	$3,828	$3,828
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Sentinel Light Maintenance	Cost Based	$12,639	$12,639
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Chisholm Roof Rental	Cost Based	$3,600	$3,600
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Water Billing	Cost Based	$670,225	$670,225
Corporate Cost Allocation					
Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Milton Hydro Holdings Inc.	*Milton Hydro Distribution Inc.*	Management Fee	Cost Based	90.0%	$20,434

In 2018, shared service charges received from the parent company, Milton Hydro Holdings Inc. ("MHHI") were lower to an increase in time spent by the Board of Directors on unregulated activities.

Table 4-66 Appendix 2-N - 2019 Actual

Shared Services					
Name of Company		**Service Offered**	**Pricing Methodology**	**Price for the Service**	**Cost for the Service**
From	**To**			**$**	**$**
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Administration Fee	Cost Based	$35,083	$35,083
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Administration Fee	Cost Based	$117,420	$117,420
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Admin Staff	Cost Based	$1,590	$1,590
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Billing Sentinel Rentals	Cost Based	$3,828	$3,828
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Sentinel Light Maintenance	Cost Based	$845	$845
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Chisholm Roof Rental	Cost Based	$3,600	$3,600
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Water Billing	Cost Based	$713,882	$713,882
Corporate Cost Allocation					
Name of Company		**Service Offered**	**Pricing Methodology**	**% of Corporate Costs Allocated**	**Amount Allocated**
From	**To**			**%**	**$**
Milton Hydro Holdings Inc.	*Milton Hydro Distribution Inc.*	Management Fee	Cost Based	90.0%	$112,224

In 2019, MHHI costs allocated to Milton Hydro increased relative to the prior year, corresponding to increased MHHI strategy development and enterprise risk management consulting costs.

Table 4-67 Appendix 2-N - 2020 Actual

Shared Services					
Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Administration Fee	Cost Based	$36,106	$36,106
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Admin Staff	Cost Based	$1,764	$1,764
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Administration Fee	Cost Based	$120,825	$120,825
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Admin Staff	Cost Based	$6,955	$6,955
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Billing Sentinel Rentals	Cost Based	$3,828	$3,828
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Chisholm Roof Rental	Cost Based	$3,672	$3,672
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Water Billing	Cost Based	$750,371	$750,371

Corporate Cost Allocation					
Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Milton Hydro Holdings Inc.	*Milton Hydro Distribution Inc.*	Management Fee	Cost Based	75.0%	$97,280

In 2020, the costs allocated from MHHI to Milton Hydro decreased relative to the prior year, corresponding to MHHI spending more time supporting the unregulated business.

Table 4-68 Appendix 2-N - 2021 Actual

Shared Services					
Name of Company					
From	**To**	**Service Offered**	**Pricing Methodology**	**Price for the Service $**	**Cost for the Service $**
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Administration Fee	Cost Based	$41,028	$41,028
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Administration Fee	Cost Based	$96,013	$96,013
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Billing Sentinel Rentals	Cost Based	$3,828	$3,828
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Chisholm Roof Rental	Cost Based	$3,745	$3,745
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Water Billing	Cost Based	$784,807	$784,807
Corporate Cost Allocation					
Name of Company					
From	**To**	**Service Offered**	**Pricing Methodology**	**% of Corporate Costs Allocated %**	**Amount Allocated $**
Milton Hydro Holdings Inc.	*Milton Hydro Distribution Inc.*	Management Fee	Cost Based	90.0%	$81,555

In 2021, the costs allocated to Milton Hydro decreased relative to the prior year due to the lower consulting costs within MHHI allocated to unregulated activities.

Table 4-69 Appendix 2-N - 2022 Bridge Year

Shared Services					
Name of Company					
From	**To**	**Service Offered**	**Pricing Methodology**	**Price for the Service $**	**Cost for the Service $**
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Administration Fee	Cost Based	$38,328	$38,328
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Administration Fee	Cost Based	$97,932	$97,932
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Billing Sentinel Rentals	Cost Based	$3,828	$3,828
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Chisholm Roof Rental	Cost Based	$3,820	$3,820
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Water Billing	Cost Based	$819,954	$819,954
Corporate Cost Allocation					
Name of Company					
From	**To**	**Service Offered**	**Pricing Methodology**	**% of Corporate Costs Allocated %**	**Amount Allocated $**
Milton Hydro Holdings Inc.	*Milton Hydro Distribution Inc.*	Management Fee	Cost Based	90.0%	$118,796

In 2022, the proportion of shared service costs is expected to remain consistent with the prior year.

Table 4-70 Appendix 2-N - 2023 Test Year

Shared Services					
Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Milton Hydro Distribution Inc.	Milton Hydro Holdings Inc.	Administration Fee	Cost Based	$39,480	$39,480
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Administration Fee	Cost Based	$99,891	$99,891
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Billing Sentinel Rentals	Cost Based	$3,828	$3,828
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Chisholm Roof Rental	Cost Based	$3,897	$3,897
Milton Hydro Distribution Inc.	Milton Energy Generation Services	Water Billing	Cost Based	$856,155	$856,155
Corporate Cost Allocation					
Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Milton Hydro Holdings Inc.	*Milton Hydro Distribution Inc.*	Management Fee	Cost Based	90.0%	$120,658

In 2023, the level of Board resource allocation is expected to remain consistent with the prior year.

In reviewing shared services variances for the 2023 Test Year over 2016 Actual and 2023 Test Year over 2021 Actual, there are no material variances except for Water Billing. Water Billing in the 2023 Test Year is higher than 2016 Actual by $249,905. This increase is primarily due to customer growth and inflation over this period.

4.5.5. Reconciliation of Revenues from Affiliates

Milton Hydro’s Distribution Inc.'s services provided to and received from its affiliates as outlined in Board Appendix 2-N are reconciled as recorded in Uniform System of Accounts ("USoA") accounts in Table 4-71 below. Some of the services are found in revenues and others are recorded as a reduction to OM&A cost. Considerable effort is made by Milton Hydro to ensure affiliates are charged properly and do not receive any benefits as a result of their affiliation.

Table 4-71 Reconciliation of Services to Affiliates

Item	Source Account	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
Appendix 2-N Shared Services									
Exhibit 4: Reduction to OM&A	4390 - Misc Non-Operating Income	606,249	631,089	670,224	717,562	750,371	784,807	819,954	856,155
	5625 - Admin Expense Transferred Credit	16,560	100,200	109,175	154,136	156,930	133,884	120,658	122,554
	5620 Office Supplies and Expenses	180	180	180	180	180	180	180	180
	Total	**622,989**	**731,469**	**779,579**	**871,878**	**907,481**	**918,871**	**940,792**	**978,889**

4.5.6. Purchases of Non-Affiliate Services

Milton Hydro purchases goods and services from a number of non-affiliated third parties. Milton Hydro's Corporate Purchasing Policy (Attachment 4-6) helps to ensure purchases are made in a cost-effective manner with full consideration given to price, goods or service quality, the ability to deliver on time, reliability and compliance with engineering specifications and standards.

Milton Hydro's Corporate Purchasing Policy operates in conjunction with the Corporate Expenditure Authorization Policy (Attachment 4-7) and establishes the principles, requirements, accountabilities and guidelines for the purchase of goods and services. The policies outline authorization levels, requirements and approvals necessary to appropriately purchase goods and services from suppliers, vendors and contractors through the use of competitive bids, quotations and awards.

These policies help to ensure that all procurement activities of Milton Hydro follow legal, ethical, managerial, and professional standards. Milton Hydro's purchasing policy does identify certain situations where a competitive bid process may not be required. Milton Hydro confirms that its non-affiliate purchases are in compliance with its purchasing policy and that there are no material transactions which are not in compliance with its purchasing policy.

Milton Hydro is a member of the GridSmartCity Cooperative ("GSC Cooperative"), a group of fifteen LDC members who manage approximately $2.7 Billion in assets and serve approximately 737,500 customers. The GSC Cooperative bridges the need for innovation and infrastructure renewal, with the benefits of collaboration and cost efficiency. The GSC Cooperative leverages its size to increase its purchasing power and Milton Hydro participates in joint RFPs, RFQs, and information sharing and networking sessions. Benefits of cooperative purchasing include:

- Securing preferential pricing and services;

- Reducing time spent on procurement across LDCs;

- Leveraging best practices;

- Implementing common specifications and standards to support joint RFPs; and

- Sourcing new or "difficult to source" goods and services.

4.6. DEPRECIATION, AMORTIZATION AND DEPLETION

4.6.1. Overview

Milton Hydro is seeking to recover $4,916,957 of net depreciation expense in the 2023 Test Year. Depreciation expense is provided by asset group and has increased $1,644,072 (50.2%) or about 6% compounded annually between 2016 Actual results and the 2023 Test Year. Milton Hydro's depreciation/amortization policy is based on IFRS and guidelines set out by the OEB, where applicable (MIFRS). Milton Hydro converted to IFRS January 1, 2015 and as such the depreciation/amortization policy in effect for the 2022 Bridge Year and 2023 Test Year is compliant with MIFRS.

4.6.2. Service Lives

In 2013, Milton Hydro implemented the change to depreciation rates and the componentization of PP&E. Milton Hydro used the *Asset Depreciation Study for the Ontario Energy Board* ("Kinectrics report") dated July 8, 2010, prepared for the OEB, as a guide and an assessment was made of remaining service lives for the purposes of determining depreciation expense on a go-forward basis. Milton Hydro confirms that significant parts or components of each item of PP&E are being depreciated separately. All significant components of each item of Property, Plant & Equipment ("PP&E") are depreciated separately for each of the 2016 Actual to the proposed 2023 Test Year amounts, using the most current estimates of useful service lives based on Milton Hydro's professional judgement and the Kinectrics report.

Depreciation is calculated in a rational and systematic manner as follows:

- Using a straight-line basis over the estimated remaining useful life of the assets;

- Amortizing capital contributions in the aid of construction and recognizing as other revenue;

- Construction in progress assets (CWIP) are not depreciated until the project is complete and in-service, essentially "used and useful";

- Actual depreciation expense is calculated automatically using Milton Hydro's fixed asset system. Actual additions to capital assets are transferred from CWIP and depreciated; and

- Depreciation of an asset ceases when the asset is retired from active use, sold or is fully depreciated.

4.6.3. Use of Half-Year Rule

Milton Hydro's capital assets related to the distribution system and capital contributions are amortized on a straight-line basis, applying the "half-year" rule in the year of addition, over the deemed life of the assets. The "half-year" rule continues to be used for the 2023 Test Year capital additions and capital contributions. Milton Hydro confirms that it has complied with the OEB's general policy for electricity distribution rate setting under which capital additions would attract six months of depreciation expense in the year the asset is put into service for both the 2022 Bridge and the proposed 2023 Test Years.

4.6.4. Capitalization of Borrowing Costs

Milton Hydro's accounting policy is to expense borrowing costs. It does not capitalize interest on capital projects unless they meet the IFRS criteria of a qualifying asset which is defined in the Board's *Report of the Board EB-2008-0408 Transition to International Financial Reporting Standards, July 28, 2009* as "an asset that necessarily takes a substantial period of time to get ready for its intended use or sale." Milton Hydro did capitalized borrowing costs on a construction loan from Infrastructure Ontario for the 2015 renovations to its Administration Building and Service Centre.

4.6.5. Changes in Depreciation Policy/Practice

Milton Hydro has made one change to its depreciation practices since its last rebasing application. Effective January 1, 2023, Milton Hydro will be including Major Spare Parts &

Equipment (MSP&SE) in rate base and the associated depreciation is included in revenue requirement. These units were previously recorded as inventory, however, upon examination, they meet the criteria of "Major Spares" as outlined in the *Accounting Procedures Handbook for Electricity*, Article 410 re. Major Spare Parts and Stand-by Equipment. These MSP&SE assets total $610,000 and are primarily transformers which are required to be available for immediate use in an emergency situation.

Milton Hydro confirms there have been no other changes to its depreciation/amortization policy since its last Cost of Service Application for 2016. Milton Hydro has applied the "half-year" rule for capital additions in accordance with Section 2.4.4 of the Chapter 2 Filing Requirements for Electricity Distribution Rate Applications.

4.6.6. Asset and Retirement Obligations

Milton Hydro does not have any Asset Retirement Obligations ("AROs"), associated depreciation or accretion expenses in relation to the AROs to report as part of this Application.

Under CGAAP, Milton Hydro recorded customer contributions as an offset to the cost of capital assets and amortized accordingly. Under MIFRS, Milton Hydro cannot include these customer contributions as part of its net capital assets, but instead classifies the contributions as a deferred revenue liability and amortizes the costs to revenue over the life of the asset the contribution relates to. For financial reporting purposes, Milton Hydro classifies customer contributions as deferred revenue and amortizes the contribution to revenue over the life of the related asset. This treatment is consistent with the *Accounting Procedures Handbook for Electricity Distributors*, Article 430.

4.6.7. Depreciation Expense Summary and Analysis

The following table provides a summary of Milton Hydro's depreciation by year.

Table 4-72 Depreciation Expense 2016-2023

Depreciation Expense									
USoA - Description	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
Distribution Assets									
1820-Dist Station Equip - Normally Primary below 50 kV	$23,011	$15,275	$11,196	$10,887	$2,492	$2,222	$932	$934	$2,684
1830-Poles, Towers and Fixtures	$414,332	$572,679	$1,767,753	$628,353	$653,147	$687,777	$720,071	$758,391	$805,667
1835-Overhead Conductors and Devices	$488,466	$305,344	($848,378)	$340,070	$410,189	$417,749	$447,099	$478,207	$513,169
1840-Underground Conduit	$530,729	$594,670	$631,006	$660,886	$706,008	$736,830	$762,721	$803,552	$826,993
1845-Underground Conductors and Devices	$468,630	$383,063	$412,848	$433,167	$466,044	$485,384	$507,926	$539,020	$563,344
1850-Line Transformers	$737,912	$751,400	$787,707	$826,576	$802,673	$898,507	$937,124	$986,386	$1,038,712
1855-Services	$265,028	$272,684	$291,401	$306,995	$327,991	$339,519	$352,822	$371,366	$385,721
1860-Meters	$741,734	$894,650	$779,471	$830,170	$894,093	$869,290	$890,184	$1,019,722	$891,510
Gross Distribution Assets	**$3,669,842**	**$3,789,764**	**$3,833,003**	**$4,037,104**	**$4,262,639**	**$4,437,278**	**$4,618,879**	**$4,957,578**	**$5,027,799**
General Plant									
1609-Capital Contributions - Paid	$3,059	$3,059	$3,059	$3,059	$27,621	$55,118	$50,073	$50,073	$50,073
1611-Computer Software	$131,363	$191,003	$249,705	$302,989	$360,286	$357,116	$294,969	$263,251	$284,063
1908-Buildings and Fixtures	$209,200	$178,873	$207,204	$207,304	$216,235	$216,897	$216,897	$222,827	$233,947
1908-Building disallowed in 2016 COS	($28,584)	($28,584)	($28,584)	($28,584)	($28,584)	($28,584)	($28,584)		
1920-Computer Equipment - Hardware	$107,997	$108,879	$112,986	$105,695	$95,606	$89,373	$85,744	$91,634	$97,604
1925-Computer Software	$46,472	$—	$—	$—	$—	$—	$—	$—	$—
1915-Office Furniture and Equipment	$40,000	$51,923	$29,010	$52,889	$50,385	$50,165	$46,056	$42,168	$42,168
1930-Transportation Equipment	$208,004	$199,155	$230,038	$254,123	$269,919	$273,819	$256,725	$290,228	$324,363
1935-Stores Equipment	$12,369	$20,108	$20,669	$21,272	$22,726	$24,233	$24,639	$25,472	$27,555
1940-Tools, Shop and Garage Equipment	$8,639	$19,725	$10,793	$19,121	$28,430	$31,837	$34,369	$37,298	$40,452
1945-Measurement and Testing Equipment	$9,476	$—	$10,824	$12,541	$14,185	$14,027	$11,064	$6,481	$4,546
1955-Communication Equipment	$103,497	$41,573	$72,588	$46,505	$44,262	$45,493	$45,429	$44,574	$43,583
1980-System Supervisory Equipment	$5,375	$8,317	$44,847	$75,940	$111,589	$133,252	$148,676	$165,163	$186,255
1990-Other Tangible Property	$13,301	$14,468	$14,468	$14,468	$14,468	$11,029	$3,795	$—	$—
Gross General Plant	**$870,168**	**$808,498**	**$977,608**	**$1,087,324**	**$1,227,129**	**$1,273,776**	**$1,189,852**	**$1,254,417**	**$1,349,858**
Contributions and Grants									
1995-Contributions and Grants - Credit	($1,163,311)	($1,106,498)	($1,105,481)	($1,105,235)	($1,105,133)	($1,105,078)	($1,101,129)	($1,101,130)	($1,095,885)
2440-Deferred Revenue	$—	($214,162)	($295,202)	($368,975)	($431,291)	($484,446)	($548,596)	($619,375)	($688,413)
Gross Contributions and Grants	**($1,163,311)**	**($1,320,660)**	**($1,400,683)**	**($1,474,210)**	**($1,536,424)**	**($1,589,523)**	**($1,649,725)**	**($1,720,505)**	**($1,784,298)**
Depreciation Expense Excluding Adjustments	**$3,376,699**	**$3,277,602**	**$3,409,927**	**$3,650,218**	**$3,953,343**	**$4,121,530**	**$4,159,006**	**$4,491,491**	**$4,593,359**
Adjustments									
Less: Transportation		($199,155)	($230,038)	($254,123)	($269,919)	($273,819)	($256,725)	($290,228)	($324,363)
Less: Tools		($19,725)	($10,793)	($19,121)	($28,430)	($31,837)	($34,369)	($37,298)	($40,452)
Less: Measurement			($10,824)	($12,541)	($14,185)	($14,027)	($11,064)		
Less: Capital Contribution		$214,162	$295,202	$368,975	$431,291	$484,446	$548,596	$619,375	$688,413
Net Depreciation	**$3,376,699**	**$3,272,885**	**$3,453,474**	**$3,733,407**	**$4,072,100**	**$4,286,293**	**$4,405,444**	**$4,783,340**	**$4,916,957**

The following table provides a summary year-over-year changes in depreciation expenditures by component. Explanations of material variances are subsequently provided.

Table 4-73 Year Over Year Variances in Depreciation Expense

Depreciation Expense Variance Year Over Year								
USoA - Description	2016 Actual vs. 2016 OEB	2017 Actual vs. 2016 Actual	2018 Actual vs. 2017 Actual	2019 Actual vs. 2018 Actual	2020 Actual vs. 2019 Actual	2021 Actual vs. 2020 Actual	2022 Bridge Year vs. 2021 Actual	2023 Test Year vs. 2022 Bridge Year
Distribution Assets								
1820-Dist Station Equip - Normally Primary below 50 kV	($7,736)	($4,079)	($309)	($8,395)	($270)	($1,290)	$2	$1,750
1830-Poles, Towers and Fixtures	$158,347	$1,195,074	($1,139,400)	$24,794	$34,630	$32,294	$38,320	$47,275
1835-Overhead Conductors and Devices	($183,122)	($1,153,722)	$1,188,449	$70,119	$7,560	$29,350	$31,108	$34,962
1840-Underground Conduit	$63,941	$36,336	$29,880	$45,122	$30,822	$25,891	$40,831	$23,441
1845-Underground Conductors and Devices	($85,567)	$29,785	$20,320	$32,877	$19,339	$22,542	$31,094	$24,324
1850-Line Transformers	$13,488	$36,307	$38,869	($23,903)	$95,833	$38,617	$49,262	$52,326
1855-Services	$7,656	$18,717	$15,594	$20,996	$11,528	$13,303	$18,544	$14,355
1860-Meters	$152,916	($115,179)	$50,699	$63,924	($24,803)	$20,894	$129,538	($128,213)
Gross Distribution Assets	**$119,922**	**$43,239**	**$204,102**	**$225,535**	**$174,639**	**$181,601**	**$338,699**	**$70,221**
General Plant								
1609-Capital Contributions - Paid	$—	$—	$—	$24,562	$27,496	($5,045)	$—	$—
1611-Computer Software	$59,640	$58,702	$53,284	$57,297	($3,170)	($62,147)	($31,718)	$20,812
1908-Buildings and Fixtures	($30,327)	$28,331	$100	$8,931	$662	$—	$5,930	$11,120
1908-Building disallowed in 2016 COS	$—	$—	$—	$—	$—	$—	$28,584	$—
1920-Computer Equipment - Hardware	$882	$4,107	($7,290)	($10,089)	($6,233)	($3,629)	$5,890	$5,969
1925-Computer Software	($46,472)	$—	$—	$—	$—	$—	$—	$—
1915-Office Furniture and Equipment	$11,923	($22,912)	$23,879	($2,504)	($221)	($4,109)	($3,888)	$—
1930-Transportation Equipment	($8,849)	$30,884	$24,085	$15,796	$3,900	($17,094)	$33,503	$34,135
1935-Stores Equipment	$7,739	$561	$603	$1,454	$1,507	$406	$833	$2,083
1940-Tools, Shop and Garage Equipment	$11,086	($8,931)	$8,328	$9,309	$3,407	$2,532	$2,929	$3,154
1945-Measurement and Testing Equipment	($9,476)	$10,824	$1,717	$1,644	($157)	($2,963)	($4,583)	($1,935)
1955-Communication Equipment	($61,924)	$31,015	($26,083)	($2,244)	$1,232	($64)	($855)	($990)
1980-System Supervisory Equipment	$2,942	$36,530	$31,093	$35,648	$21,664	$15,424	$16,487	$21,091
1990-Other Tangible Property	$1,167	$—	$—	$—	($3,439)	($7,234)	($3,795)	$—
1330-Major Spare Parts	$—	$—	$—	$—	$—	$—	$15,250	$—
Gross General Plant	**($61,670)**	**$169,110**	**$109,716**	**$139,805**	**$46,647**	**($83,924)**	**$64,565**	**$95,440**
Contributions and Grants								
1995-Contributions and Grants - Credit	$56,813	$1,017	$246	$102	$55	$3,949	($1)	$5,245
2440-Deferred Revenue	($214,162)	($81,040)	($73,773)	($62,316)	($53,155)	($64,150)	($70,779)	($69,038)
Gross Contributions and Grants	**($157,349)**	**($80,023)**	**($73,527)**	**($62,214)**	**($53,099)**	**($60,202)**	**($70,780)**	**($63,793)**
Depreciation Expense Excluding Adjustments	**($99,097)**	**$132,325**	**$240,291**	**$303,125**	**$168,187**	**$37,476**	**$332,485**	**$101,868**
Adjustments								
Less: Transportation	($199,155)	($30,884)	($24,085)	($15,796)	($3,900)	$17,094	($33,503)	($34,135)
Less: Tools	($19,725)	$8,931	($8,328)	($9,309)	($3,407)	($2,532)	($2,929)	($3,154)
Less: Measurement	$—	($10,824)	($1,717)	($1,644)	$157	$2,963	$11,064	$—
Less: Capital Contribution	$214,162	$81,040	$73,773	$62,316	$53,155	$64,150	$70,779	$69,038
Net Depreciation	**($103,814)**	**$180,589**	**$279,933**	**$338,693**	**$214,193**	**$119,151**	**$377,896**	**$133,617**

Year over year changes in depreciation expense are below the materiality threshold except for the years 2016 -2018 when there was an offsetting accounting realignment between USoA #1830 - Poles, Towers and Fixtures and USoA #1835 Overhead Conductors and Devices.

Further information on Depreciation expense is provided in Attachment 4-8 which is OEB Appendix 2-C for the years 2016 -2023.

4.6.8. Service Life Comparisons

The following Table 4-74, consistent with the OEB Appendix 2-BB, provides a summary of the life comparison between Milton Hydro's selected useful lives and those provided in Table F-1 and F-2 of the Kinectrics Report.

Table 4-74 Service Life Comparison – Appendix 2-BB

Asset Details					Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	OH Pole System	45	2.2%	45	2.2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	OH Pole System	45	2.2%	45	2.2%	Yes	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80	1830	n/a						
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	OH Devices	45	2.2%	45	2.2%	No	No
	5	OH Line Switch Motor			15	25	25	1835	n/a						
	6	OH Line Switch RTU			15	20	20	1980	System Supervisory Equipment	15	6.7%	15	6.7%	No	No
	7	OH Integral Switches			35	45	60	1835	OH Remote Switches	20	5.0%	35	2.9%	No	No
	8	OH Conductors			50	60	75	1835	OH Wires	45	2.2%	45	2.2%	Yes	No
	9	OH Transformers & Voltage Regulators			30	40	60	1850	Distribution Transformers	40	2.5%	40	2.5%	No	No
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55	1835	OH Devices	45	2.2%	45	2.2%	No	No

		Asset Details		Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type		MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
TS & MS	12	Power Transformers	Overall	30	45	60	1850	Distribution Transformers	40	2.5%	40	2.5%	No	No
			Bushing	10	20	30								
			Tap Changer	20	30	60								
	13	Station Service Transformer		30	45	55	1850	Distribution Transformers	40	2.5%	40	2.5%	No	No
	14	Station Grounding Transformer		30	40	40	1850	Distribution Transformers	40	2.5%	40	2.5%	No	No
	15	Station DC System	Overall	10	20	30	1980	System Supervisory Equipment	15	6.7%	15	6.7%	No	No
			Battery Bank	10	15	15								
			Charger	20	20	30								
	16	Station Metal Clad Switchgear	Overall	30	40	60	1820	Switchgear	30	3.3%	30	3.3%	No	No
			Removable Breaker	25	40	60	1820	Switchgear	30	3.3%	30	3.3%	No	No
	17	Station Independent Breakers		35	45	65	1820	n/a						
	18	Station Switch		30	50	60	1820	Substation Equipment	30	3.3%	30	3.3%	No	No
	19	Electromechanical Relays		25	35	50	1820	Substation Equipment	30	3.3%	30	3.3%	No	No
	20	Solid State Relays		10	30	45	1820	Substation Equipment	30	3.3%	30	3.3%	No	No
	21	Digital & Numeric Relays		15	20	20	1820	n/a						
	22	Rigid Busbars		30	55	60	1820	n/a						
	23	Steel Structure		35	50	90	1820	Substation Equipment	30	3.3%	40	2.5%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables		60	65	75	1845	n/a						
	25	Primary Ethylene-Propylene Rubber (EPR) Cables		20	25	25	1845	n/a						
	26	Primary Non-Tree Retardant (TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried		20	25	30	1845	n/a						
	27	Primary Non-TR XLPE Cables in Duct		20	25	30	1845	n/a						
	29	Primary TR XLPE Cables in Duct		35	40	55	1845	UG Cable System	40	2.5%	40	2.5%	No	No
	30	Secondary PILC Cables		70	75	80								
	31	Secondary Cables Direct Buried		25	35	40	1855	UG Cable System	40	2.5%	40	2.5%	No	No
	32	Secondary Cables in Duct		35	40	60	1855	UG Cable System	40	2.5%	40	2.5%	No	No
			Overall	20	35	50	1850	Distribution Transformers	40	2.5%	40	2.5%	No	No
				20	35	40								
	34	Pad-Mounted Transformers		25	40	45	1850	Distribution Transformers	40	2.5%	40	2.5%	No	No
	35	Submersible/Vault Transformers		25	35	45	1850	Distribution Transformers	40	2.5%	40	2.5%	No	No
	36	UG Foundation		35	55	70	1840	Duct & Civil	40	2.5%	40	2.5%	No	No
			Overall	40	60	80	1840	Duct & Civil	40	2.5%	40	2.5%	No	No
				20	30	45								
	38	UG Vault Switches		20	35	50	1845	UG Cable System	40	2.5%	40	2.5%	No	No
	39	Pad-Mounted Switchgear		20	30	45	1845	Pad Mounted Switchgear	20	5.0%	20	5.0%	No	No
	40	Ducts		30	50	85	1840	Duct & Civil	40	2.5%	40	2.5%	No	No
	41	Concrete Encased Duct Banks		35	55	80	1840	Duct & Civil	40	2.5%	40	2.5%	No	No
	42	Cable Chambers		50	60	80	1840	Duct & Civil	40	2.5%	50	2.0%	No	No
S	43	Remote SCADA		15	20	30	1980	System Supervisory Equipment	15	6.7%	15	6.7%	No	No

Table F-2 from Kinetrics Report1

#	Asset Details Category| Component | Type		Useful Life Range		USoA Account Number	USoA Account Description	Current Years	Current Rate	Proposed Years	Proposed Rate	Outside Range of Min, Max TUL? Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Equipment	10	10.0%	10	10.0%	No	No
2	Vehicles	Trucks & Buckets	5	15	1930	Vehicles - Heavy	12	8.3%	12	8.3%	No	No
		Trailers	5	20	1930	Vehicles - Light	8	12.5%	8	12.5%	No	No
		Vans	5	10	1930	Vehicles - Other Mobile Equipment	12	8.3%	12	8.3%	No	Yes
3	Administrative Buildings		50	75	1908	Administrative Buildings	50	2.0%	50	2.0%	No	No
4	Leasehold Improvements		Lease dependent		1910	Leasehold Improvements	5	20.0%	5	20.0%		
5	Station Buildings	Station Buildings	50	75		n/a						
		Parking	25	30		n/a						
		Fence	25	60		n/a						
		Roof	20	30		n/a						
6	Computer Equipment	Hardware	3	5	1920	Computer Hardware	5	20.0%	5	20.0%	No	No
		Software	2	5	1925	Computer Software	5	20.0%	5	20.0%	No	No
7	Equipment	Power Operated	5	10	1940	Power Operated	10	10.0%	10	10.0%	No	No
		Stores	5	10	1935	Stores Equipment	12	8.3%	12	8.3%	No	Yes
		Tools, Shop, Garage Equipment	5	10	1940	Major Tools	10	10.0%	10	10.0%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement & Testing Equipment	10	10.0%	10	10.0%	No	No
8	Communication	Towers	60	70	1955	n/a						
		Wireless	2	10	1955	Communication Equipment	10	10.0%	10	10.0%	No	No
9	Residential Energy Meters		25	35	1860	n/a		—%				
10	Industrial/Commercial Energy Meters		25	35	1860	n/a		—%				
11	Wholesale Energy Meters		15	30								
12	Current & Potential Transformer (CT & PT)		35	50								
13	Smart Meters		5	15	1860	Meters	15	—%	15	6.7%	No	No
14	Repeaters - Smart Metering		10	15	1860	Meters	15	—%	15	6.7%	No	No
15	Data Collectors - Smart Metering		15	20	1860	Meters	15	—%	15	6.7%	No	No

USofA 1830: OH Pole System. The Kinectrics minimum useful life is 50 years. Milton Hydro uses a 45 year service life as approved in the EB-2015-0089 proceeding.

USofA 1835: OH Wires. The Kinectrics minimum useful life is 50 years. Milton Hydro uses a 45 year service life as approved in the EB-2015-0089 proceeding.

UsofA 1835: OH Remote Switches. Milton Hydro current service life is 20 years. Proposed to increase to 35 years to be consistent with the minimum Kinectrics service life.

USofA 1820: Substation Equipment - Steel Structures. Milton Hydro current service life is 30 years. Proposed to increase to 40 years to be within Kinectrics service life range.

USofA 1840: Duct & Civil -Cable Chambers: Milton Hydro current service life is 40 years. Proposed to increase to 50 years to be within Kinectrics service life range.

USofA 1930: Vehicles - Other Mobile Equipment. Proposed to increase to 12 years (which is beyond Kinectrics 10 year maximum useful life) based on operating experience with assets in this category.

USofA 1935: Stores Equipment. Proposed to increase to 12 years (which is beyond Kinectrics 10 year maximum useful life) based on operating experience with assets in this category

4.7. INCOME TAXES AND PAYMENTS IN LIEU OF TAXES AND PROPERTY TAXES

4.7.1 PILs and Capital Taxes

Milton Hydro makes payments in lieu of corporate taxes ("PILs") in accordance with the rules for computing taxable income, taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), as modified by the *Electricity Act, 1998*, and related regulations. Milton Hydro does not pay Section 89 proxy taxes and is exempt from the payment of incomes taxes under the *Income Tax Act* (Canada) and the *Ontario Corporations Tax Act*. Milton Hydro is projecting a profit for tax purposes in the 2023 Test Year of $1,912,869, therefore, it has determined that it would incur PILs expenses of $502,825 for Regulatory Purposes, under MIFRS.

Table 4-88 below provides a summary of the 2016 OEB Approved, and the historical statutory taxes from 2016 to 2020, the projected statutory taxes for 2021, and the projected 2022 Bridge Year and 2023 Test Year PILs forecasts for regulatory rate making purposes. The tax projections for 2022 and 2023 are based on the federal and provincial corporate income tax rates in effect when the OEB Tax/PILs model was released. See, the OEB's Income Tax/PILs Workform for 2023 Filers as provided in Attachment 4-9. Also, Milton Hydro's 2020 tax return has been provided as Attachment 4-10. At time of filing this rate application, Milton Hydro has not filed its 2021 Corporate Income Tax Return with the Canada Revenue Agency (CRA), as a result the information included in the 2021 Historical year in the Income Tax/PILs model could potentially change. Once Milton Hydro has filed its 2021 statutory corporate income tax return with the CRA, then Milton Hydro will use the information from its T2 return to update the 2021 projection, and it will make any updates to the 2022 Bridge Year and 2023 Test Year Income Tax/PILs model as required and incorporate in an update to the rate application, either as part of the Interrogatory Responses or as part of the Draft Rate Order. In accordance with the 2022 Filing Requirements, Milton Hydro has completed and submitted the Income Tax/PILs model and the output from the Income Tax/PILs model for the 2023 Test Year has been appropriately grossed up and included in the Revenue Requirement calculations consistent with the RRWF. Milton Hydro notes that it does pay Ontario Capital Tax.

Table 4-75 Income Tax Summary

Item	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Projected	2022 Bridge Year	2023 Test Year
Current PILS	$254,201	($196,556)	($729,191)	($414,892)	$1,923,679	$314,915	($630,941)	$16,399	$502,825

In Milton Hydro's 2016 Cost of Service Application, the OEB approved $254,201 for Income Tax/ PILs. The actual PILs for 2016 of $(196,556) were lower than the amount approved due to lower income for tax purposes and the impact of regulatory reserve which are excluded from the calculations of PILs for regulatory purposes but included in the calculation for tax purposes.

During 2019, the Ministry of Finance (MoF) completed an Income Tax/PILs audit for tax years 2015 & 2016. The tax impact of the adjustments is $909,000 plus an estimated $180,000 in interest. The majority of the adjustments relate to timing differences resulting from improper asset classification as determined by the MoF, with the exception of minor permanent differences (< $10K) and the non-deductible interest. The liability was accrued in 2019 and paid in 2020. In addition to this there were no overhead and repair costs capitalized in 2019 the average of which from 2016 Actual to 2018 Actual was $1.1 million resulting in higher taxable income.

PILs for the 2023 Test Year of $502,825 are $486,426 higher than the 2022 Bridge Year. This increase is mainly due to an increase in the 2023 Test Year taxable income as compared to the 2022 Bridge Year in the amount of $1,219,999, the addition to taxable income related to the PILs smoothing adjustment made in 2023 of $773,421, partially offset due to a reduction of $178.663 to taxable income regarding the net tax effect relating to Depreciation and Amortization vs Capital Cost Allowance accounting for $480,911 of the variance.

4.7.2. Loss Carry Forwards

Milton Hydro does not have any loss carry forwards.

4.7.3. Other Additions and Deductions

In accordance with the Filing Requirements, Milton Hydro has excluded the deferral and variance accounts for Regulatory Assets and Liabilities from the reserve balances for the 2022 Bridge Year and the 2023 Test Year.

4.7.4. Tax Credits

Milton Hydro has not been able to take advantage of tax credits to minimize taxes payable. Table 4-76 below summarizes the tax credits for 2023 OEB approved, historical years, 2016 to 2021, the 2022 Bridge Year and the 2023 Test Year. Milton Hydro will continue to assess tax credits to determine if there are any opportunities to utilize possible credits such as Ontario Apprenticeship Training Tax Credit, Apprenticeship Job Creation Credits and the Ontario Co-Operative Education Tax Credit. At this time for 2022 and 2023 MHDI does not forecast the use of any tax credits available.

Table 4-76 Tax Credits

Item	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
Tax Credits	$—	$—	$—	$—	$—	$—	$—	$—	$—

4.7.5. Corporate Minimum Tax

The taxable income expected in 2022 $(190,396) and as a result corporate minimum tax for 2022 Bridge Year is expected to be $66,854, resulting in a smoothing adjustment in the 2023 Test Year of ($4,085).

Table 4-77 Corporate Minimum Tax

Item	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
Minimum Tax	$—	$—	$—	$—	$—	$—	$—	$66,854	($4,085)

4.7.6. Non-recoverable and Disallowed Expenses

Milton Hydro has no non-deductible and disallowed expenses expected in the 2023 Test Year.

4.7.7. Accelerated Investment Initiative for CCA

4.7.7.1. Record Impacts of CCA Rule Changes to Account 1592

As per the OEB's July 25, 2019, letter, the OEB expected Distributors to:

- One of the changes introduced by Bill C-97 is the Accelerated Investment Incentive (AII) program, which provides for a first-year increase in capital cost allowance (CCA) deductions on eligible capital assets acquired after November 20, 2018.

- Record the full revenue requirement impact of any changes in CCA rules that are not reflected in base rates in Account 1592 – PILs and Tax Variances – CCA Changes.

- Bring forward any amounts tracked in Account 1592 - PILS and Tax Variances - CCA Changes for review and disposition in accordance with the OEB's filing requirements for the disposition of deferral and variance accounts, which would generally coincide with a distributor's next cost-based rate application.

Milton Hydro has complied with the OEB's letter dated July 25, 2019, and has recorded the full revenue requirement impact of changes in CCA rules that were not reflected in base rates. In Exhibit 9, sub-section 9.5.2 Request for Disposal of Group 2 accounts, Milton Hydro requests disposal of the projected liability of $995,185 to the end of December 31, 2022.

4.7.7.2 Accelerated CCA Smoothing Adjustment

The Bill C-97 rule changes relating to the AII are in full effect until 2023. From 2024 to 2027 the AII is gradually phased out. The impact of the declining benefit of the AII is that the CCA established in Milton Hydro's 2023 test year is effectively overstated. Milton Hydro has calculated a CCA smoothing adjustment to reflect the fact that the CCA is gradually declining from the high point in 2023, through to the phase out by 2027. Rather than use an effectively overstated amount of the CAA in 2023, and subsequently record balances for recovery in Account 1592 in the years from 2024 to 2027, Milton Hydro has forecasted what its CCA would be for the years from 2024 to 2027 based on the declining benefit of the AII, and then calculated the average AII for the 5-year period, and then made a smoothing adjustment for the declining benefit from the AII.

The following table illustrates how Milton Hydro calculated the adjustment to smooth the impact of CCA in the 2023 Test Year. The expected CCA from 2023 to 2027 is shown below and is expected to be $2,376,577 on average as compared to the test year CCA of $3,149,998 with a CCA smoothing adjustment of a $733,420 reduction to CCA required in 2023.

Table 4-78 Accelerated CCA Smoothing Adjustment

Description	2023	2024	2025	2026	2027
Accelerated CCA - no phase out	($3,149,998)	($3,149,998)	($3,149,998)	($3,149,998)	($3,149,998)
Accelerated CCA - phased out 2024 to 2027	($3,149,998)	($3,258,608)	($1,956,823)	($1,795,584)	($1,721,875)
Additional CCA	$—	$108,610	($1,193,175)	($1,354,414)	($1,428,123)
Five-Year Average	($773,420)				
Adjustment to Smooth the CCA impact	**$773,420**				

4.7.8. Detailed Tax Calculations

Table 4-79 below summarizes the tax calculations for the following:

- 2016 OEB Approved Income Tax/PILs calculations
- 2017 to 2020 historical statutory tax calculations based on T2 Tax Returns filed with the CRA.
- 2021 Historical year projected statutory tax calculation based on expected T2 Tax Return.
- 2022 Bridge Year and the 2023 Test Year projected Income Taxes/PILs on a regulatory rate setting basis.

Table 4-79 below itemizes all additions and deductions that are part of Milton Hydro's tax calculations. For all years from 2016 to 2021, the change in regulatory assets/liabilities are reflected in the tax calculations, note however for rate setting purposes, Milton Hydro has not included the change in regulatory assets/liabilities in its income tax/PILs calculations.

Table 4-79 Tax Calculations

Details	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
Income before PILS/Taxes	**$3,509,977**	**$2,953,013**	**$2,963,385**	**$4,302,995**	**$1,997,969**	**$1,058,212**	**$4,012,025**	**$2,714,447**	**$3,934,446**
Additions:									
Provision for income taxes - current		$762,962	$888,791	$1,267,424	$721,235	$287,670			
Interest and penalties on taxes			$897		$181,713				
Amortization of tangible assets	$3,195,805	$3,326,285	$3,480,949	$3,908,120	$4,025,308	$4,222,325	$4,391,144	$4,782,292	$4,932,386
Amortization of intangible assets	$180,894	$194,061	$252,765		$387,907	$412,234	$345,042	$313,323	$334,136
Loss from Retirement of Utility and Other Property		$144,173	$359,103	$25,965	$49,291	$484,742	$141,009	$350,000	$350,000
Charitable donations		$5,860	$3,390	$1,410	$10,022	$4,000	$2,750		
Non-deductible club dues and fees		$923		$554					
Non-deductible meals and entertainment expense	$4,545	$5,905	$5,988	$9,071	$5,284	$2,003	$2,071	$4,780	$5,000
Reserves from financial statements – balance at the end of the year	$319,821	$319,821	$482,392	$496,556	$509,917	$669,800	$617,629	$617,629	$617,629
Unrealized gains / losses on derivatives						$1,375,956			
Inducement under 12(1)(x) ITA		$3,562		$10,890	$8,945	$2,690			
Taxable/non-deductible other comprehensive income			$101,797						
Deferred Revenue (ITA 12(1)(a))		$5,698,383	$5,315,895	$5,630,823	$6,235,340	$6,722,937	$20,547,338	$20,553,396	$22,404,815
Opening regulatory balance (debit)		$24,952		$1,053,403	$2,293,903				
Ending regulatory balance (credit)		$843,090			$493,523	$1,432,269			
Capital contributions received 12(1)(x)		$3,333,020	$2,879,515	$2,920,318	$2,025,360	$2,303,048			
Tax expense incl. in net movements in reg. balance on P&L					$412,248				
Gym membership				$105	$1,440				
EFB Reserve Adj to open balance				$3,159					
PP&E movement in reg. change					$173,890				
PILs regulatory smoothing adjustment									$773,421
Total Additions	**$3,701,065**	**$14,662,997**	**$13,771,482**	**$15,327,798**	**$17,535,326**	**$17,919,674**	**$26,046,983**	**$26,621,420**	**$29,417,387**
Deductions:									
Capital cost allowance from Schedule 8	$5,947,708	$5,723,366	$5,814,962	$5,886,754	$7,075,144	$6,545,265	$6,404,034	$7,735,863	$7,728,107
Cumulative eligible capital deduction from schedule 10		$5,167							
Reserves from financial statements - balance at beginning of year	$304,086	$304,086	$319,821	$482,392	$496,556	$509,917	$669,800	$617,629	$617,629
Contributions to deferred income plans from Schedule 15		$90,063	$103,142	$103,191	$126,337	$97,085			
Deferred Revenue - ITA 20(1)(m) reserve		$5,698,383	$5,315,895	$5,630,823	$6,235,340	$6,722,937	$20,547,338	$20,553,396	$22,404,815
Financing Fees 20(1)(e)		$1,889							
Amortization of Deferred Revenue		$214,162	$295,202	$368,974	$431,291	$484,446	$548,596	$619,375	$688,413
Overhead capitalized for accounting		$1,821,932	$2,038,160	$1,667,688					
Repair costs capitalized for accounting		$181,850	$86,168	$826,981					
Tax recovery incl. in net movements in reg. balance on P&L		$983,814	$598,674	$1,015,398		$424,151			
Capital contributions received 12(1)(x)		$3,333,020	$2,879,515	$2,920,318	$2,025,360	$2,303,048			
Opening regulatory balance (credit)			$843,090			$667,311	$1,432,269		
Ending regulatory balance (debit)			$1,053,403	$2,293,904			$2,018,885		
Non-taxable OCI, reversed as part of Sch 13s			$138,500			$35,366			
Unrealized gains / losses on derivatives							$818,996		
Total Deductions	**$6,251,794**	**$18,357,732**	**$19,486,532**	**$21,196,423**	**$16,390,028**	**$17,789,526**	**$32,439,918**	**$29,526,263**	**$31,438,964**
Taxable Income	**$959,248**	**$(741,722)**	**$(2,751,665)**	**$(1,565,630)**	**$3,143,267**	**$1,188,360**	**$(2,380,910)**	**$(190,396)**	**$1,912,869**
Tax Rate	26.5 %	26.5 %	26.5 %	26.5 %	26.5 %	26.5 %	26.5 %	26.5 %	26.5 %
Income Taxes	$254,201	$(196,556)	$(729,191)	$(414,892)	$832,966	$314,915	$(630,941)	$(50,455)	$506,910
Corporate Minimum Taxes								$66,854	$(4,085)
Tax Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Income Taxes	**$254,201**	**$(196,556)**	**$(729,191)**	**$(414,892)**	**$832,966**	**$314,915**	**$(630,941)**	**$16,399**	**$502,825**
MOF Assessment					$1,090,713				
Total Income Taxes & Financial Statements	**$254,201**	**$(196,556)**	**$(729,191)**	**$(414,892)**	**$1,923,679**	**$314,915**	**$(630,941)**	**$16,399**	**$502,825**
Total Income Taxes Grossed up									**$684,115**

4.7.9. Integrity Checks

Milton Hydro has completed the integrity checks for the following information as detailed in the filing requirements.

- The depreciation and amortization added back in the PILs model agree with the numbers disclosed in the rate base section of the application. It was also reconciled with Appendix 2-BA Fixed Asset Continuity schedule of the Chapter 2 appendices.

- The capital additions and deductions in the UCC/CCA schedule 8 agree with the rate base section for historic, bridge and test years. However, Milton Hydro has not filed its 2021 T2 Income Tax return with the CRA, and information used for 2021 was preliminary information, therefore information used for 2021 is subject to change until Milton Hydro files its T2 Income Tax return for 2021 with the CRA later this spring.

- Milton Hydro has included a copy of its most recent 2020 Federal T2 Income Tax return filed with the CRA. Milton Hydro confirms that non-distribution tax amounts on Schedule 8 were $0 on the December 31, 2020, tax return, and that non-distribution tax amounts projected on Schedule 8 for 2021 were zero as well.

- The CCA deductions in the PILs tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application.

- Milton Hydro does not have any loss carry-forwards.

- CCA is maximized for the 2022 Bridge Year and the 2023 Test Year since Milton Hydro does not have any loss carry-forwards.

- Post-retirement benefit obligations added back on Schedule 1, the reconciliation of accounting income to net income for tax purposes, agree with the amounts provided in the OM&A analysis for compensation.

- The income tax rate used to calculate the tax expense is consistent with the Milton Hydro's actual tax facts and the evidence filed in the application.

4.7.10. Property Taxes

Milton Hydro pays property taxes to the Town of Milton for its Head Office administrative and operations facility at 200 Chishlom Drive and also on its transformer substations. Property taxes for transformer substations are included in the Transformer Stations OM&A work program. The 2016 Board Approved level of property taxes, actual amounts for the 2016-2021 period, budgeted amounts for the 2022 Bridge Year and the 2023 Test Year are provided in Table 4-80 below. Property taxes for the 2023 Test Year are $223,090 and the increase in 2023 over 2021 actual results reflects the continuation of the trend in increased property taxes experienced over the 2016 - 2021 period.

Table 4-80 Property Taxes

Paid to "The Corporation of the Town of Milton"	2016 OEB Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
General Administration	$119,949	$116,574	$132,167	$144,775	$157,190	$170,839	$172,533	$179,500	$200,193
Transformer Substations	$21,880	$19,417	$18,287	$16,553	$18,210	$17,681	$17,966	$20,532	$22,897
Total	**$141,829**	**$135,991**	**$150,454**	**$161,328**	**$175,400**	**$188,520**	**$190,499**	**$200,032**	**$223,090**

4.8. CONSERVATION AND DEMAND MANAGEMENT ("CDM") COSTS

4.8.1. Lost Revenue Adjustment Mechanism ("LRAM") for 2021-2022

Milton Hydro proposes to recover an LRAMVA (Account 1568) amount of $533,342 for CDM activities persisting to 2021 to 2022, including carrying charges to December 31, 2022. This claim includes persistence of 2015-2020 activities to 2021 and 2022 as well as a small amount 2021 and 2022 activities. Milton Hydro's last LRAMVA claim was approved as part of its 2022 IRM proceeding for savings from 2015 to 2020.

Milton Hydro is not currently running any CDM programs and confirms that no CDM costs are included in its test year revenue requirement.

4.8.2. Background

On March 31, 2011, the Minister of Energy and Infrastructure issued a directive (the "Directive") to the OEB regarding electricity CDM targets to be met by licensed electricity distributors. On April 26, 2012, the OEB issued Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003 – the "CDM Guidelines"). In keeping with the Directive, the OEB adopted a mechanism to capture the difference between the results of actual, verified impacts of authorized CDM activities undertaken by distributors.

In the Guidelines, the OEB authorized the establishment of LRAMVA Account 1568 (LRAMVA) to capture, at the customer rate class level, the difference between:

- The results of actual, verified impacts of authorized CDM activities undertaken by distributors for both OEB-Approved CDM programs and OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or are delivered for the distributor by a third party under contract (in the distributor’s franchise area), and

- The level of CDM program activities included in the distributor’s load forecast (i.e., the level embedded in rates).

On March 26, 2014, the Minister of Energy issued a directive regarding the new Conservation First Framework ("CFF") for conservation and demand management activities in place from 2015 to 2020 and continuance of the lost revenue adjustment mechanism.

On March 20, 2019, the Minister of Energy, Northern Development and Mines (“MENDM”) issued a directive to the IESO mandating the discontinuance of the CFF and the establishment of an Interim Framework for CDM programming. Under the Interim Framework, the new province-wide target for CDM savings was 1.4 TWh and the framework was scheduled to expire on December 31, 2020.

Subsequent to the discontinuance of the 2015-2020 CFF, on June 20, 2019, the OEB issued a letter to distributors stating that distributors should continue to have access to LRAM related to the successful delivery of CFF programs. In addition, the OEB updated the Chapter 2 filing requirements to make modifications reflecting the new requirements set forth in the Interim Framework.

On July 22, 2020, the MENDM issued a directive to the IESO mandating the extension of timelines for certain projects and related deadlines under the CFF to June 30, 2021. These extensions are intended to offset the disruptions caused by COVID-19 for participants and those businesses involved in delivering CDM programs. Contracted program participants in the certain CFF programs are eligible for project extensions to June 30, 2021 (Retrofit Program, Process and Systems Upgrade Program, Residential New Construction Program, High Performance New Construction Program).

4.8.3. LRAM Variance Account (LRAMVA)

Milton Hydro is applying for disposition of Account 1568 – LRAMVA to recover lost revenues in the amount of $533,342. Milton Hydro is requesting disposition of the net lost revenues from savings resulting from programs offered in 2015 to 2020 persisting to 2021 and 2022, savings of projects approved before April 1, 2019, but were completed in 2021 and 2022, and carrying charges on these amounts through December 31, 2022. Milton Hydro confirms its claim for 2021 and 2022 are considered final.

A summary of the LRAMVA disposition request by customer class including projected carrying charges to December 31, 2022, is as follows:

Table 4-81 Summary of LRAMVA Claim

Description	Principal	Carrying Charges to Dec. 2022	Total LRAMVA Claim
Residential (kWh)	$—	$—	$—
General Service < 50 kW (kWh)	$249,188	$1,392	$250,580
General Service < 50 - 999 kW (kW)	$103,950	$634	$104,584
General Service < 1000 - 4999 kW (kW)	$51,264	$289	$51,553
Large User (kW)	$24,536	$135	$24,671
Unmetered Scattered Load (kWh)	$—	$—	$—
Sentinel Lighting (kW)	$—	$—	$—
Street Lighting (kW)	$101,404	$552	$101,956
Total	**$530,341**	**$3,001**	**$533,342**

Milton Hydro disposed of an LRAMVA balance of $1,150,011 as part of its 2022 IRM proceeding (EB-2021-0042). This disposition included the net lost revenues from persistent savings in 2015 of programs offered in 2011 to 2014 and net lost revenues from savings resulting from programs offered in 2015 to 2020 including in-year results and persistence of savings to December 31, 2020, plus carrying charges to December 31, 2021.

The LRAMVA is intended to capture the variance between the level of CDM program activities included in the LDC’s Board-approved load forecast and the results of actual, verified impacts of CDM activities undertaken by the LDC.

Milton Hydro retained IndEco Strategic Consulting Inc. ("IndEco") to develop its 2023 LRAMVA claim, their full report is available in Attachment 4-11. In accordance with the filing requirements, Milton Hydro has also included the OEB LRAMVA work form as part of Attachment 4-11 and has also provided a working Microsoft Excel file with the application. IndEco used the most recent input assumptions available at the time of the program evaluation, including the following information:

- 2017 final verified results report for Milton Hydro (IESO) – For program years 2015–2017
- 2015, 2016 and 2017 Final Verified Results by Project (IESO) – For program years 2015–2017
- April 2019 Participation & Cost Report for Milton Hydro (IESO) – For program years 2018 to March 2019
- Milton Hydro CDM Databases – For program years 2018 to March 2019
- 2017 Final Verified Results Report for Milton Hydro (IESO) - For program years 2018 to March 2019
- Milton Hydro CDM Databases – For program years 2018 to 2022
- 2017 Final Verified Results Report for Milton Hydro (IESO) - For program years 2018 to 2022

Milton Hydro proposes to recover the LRAMVA amount of $533,342 through class-specific volumetric rate riders that would be in effect for a period of 24 months, from January 1, 2023, to December 31, 2024. The class-specific rate riders were determined by totaling the class-specific LRAMVA amount by program and dividing by volumetric billing determinants consistent with the proposed load forecast.

4.8.4. Conservation Reform

On March 20, 2019, the Conservation First Framework ("CFF") was discontinued effective immediately as per Ministerial Directives to the OEB and the IESO. With the discontinuance of the CFF, electricity distributors will no longer receive any preliminary or final annual verified results for conservation program activities undertaken in later years. These verified results have been available for conservation program activities for the first three years of the CFF (2015, 2016 and 2017).

The IESO monthly Participation and Cost Report for Milton Hydro Distribution Inc. dated April 15, 2019, is the final Participation and Cost Report, and includes verified results through 2017, unverified adjustments to 2016 and 2017 results, and unverified results for programs from January 1, 2018, to March 31, 2019.

The IESO did not provide reports on additional results that came in after March 31, 2019. Milton Hydro drew on its own databases for these results and adjusted the reported results to net energy and net demand using net-to-gross and realization rate factors from the 2017 final verified results report.

4.8.5. Methodology for Calculating LRAMVA

Between 2011 and 2022 Milton Hydro administered only IESO-Contracted Province-Wide CDM programs and did not have any Board-Approved programs. Since Milton Hydro did not have any Board-Approved CDM programs, it does not require an independent third-party review of its CDM savings as detailed in Section 6.1 of the Conservation and Demand Management Code (September 16, 2010).

The 2015-2017 IESO Final Savings Report and April 2019 IESO Participation and Cost Report are the sources of the CDM savings used to calculate LRAMVA amounts related to IESO programs. In addition, multiple projects were completed subsequent to the release of the April 2019 IESO Participation and Cost Report. For these, Milton Hydro relied on its internal CDM databases that capture reported energy and demand savings. These have the same values Milton Hydro reports to the IESO for incentive payments. For the LRAMVA claim, these were adjusted using net-to-gross and realization-rate factors in the 2017 final verified results report to get the net savings.

4.8.5.1. LRAMVA Threshold Calculation

The LRAMVA amount was calculated by deducting the LRAMVA threshold from the net energy or demand savings (kW or kWh) for each program, and then multiplying by the Board approved volumetric distribution charge for the applicable rate class, on a year-by-year basis. Regulatory asset recovery riders were excluded from the approved rates in calculating the LRAMVA amounts. In accordance with the filing requirements, Milton Hydro has included the OEB LRAMVA work form in Microsoft Excel format with the application.

In Milton Hydro's 2016 COS application (EB-2015-0089), a forecast of CDM savings was provided to serve as the basis of the LRAMVA threshold and was subsequently used to calculate the manual adjustment. This was set out in Table 3-6 of the application. During the rate proceeding, several modifications were made to this table. The regression analysis was updated to include actual power consumed by each customer class up to October 2015.

Consequently, 2014 CDM savings are captured in the load forecast, and do not form part of the CDM threshold. In addition, after discussions with the Town of Milton, it was determined that streetlight retrofits would not occur until after 2016, and thus they were removed from the CDM forecast savings. The resulting threshold is set out below:

Table 4-82 LRAMVA Threshold Calculation (kWH)

Class	2014 Persistence	2015 Bridge Year	2016 Test Year	Initial LRAMVA Threshold	Less Adj.	Final LRAMVA Threshold
Residential	1,943,898	774,900	858,100	3,576,898	(1,943,898)	1,633,000
GS < 50 kW	183,752	388,008	379,639	951,399	(183,752)	767,647
GS 50 - 999 kW	561,426	1,484,091	1,469,818	3,515,335	(561,426)	2,953,909
GS 1000 - 4999 kW	66,700	159,162	632,234	858,096	(66,700)	791,396
Large User		217,139		217,139		217,139
USL						—
Sentinel Lighting						—
Street Lighting		1,555,100	2,221,600	3,776,700	(3,776,700)	—
Total	**2,755,776**	**4,578,400**	**5,561,391**	**12,895,567**	**(6,532,476)**	**6,363,091**

The table below shows the LRAMVA threshold. The difference between the amounts stated below and the actual verified final program results form the basis of the LRAMVA amount available for recovery from customers.

Table 4-83 Approved 2016 LRAMVA Threshold

Class	kWh	kW
Residential	1,633,000	
GS < 50 kW	767,647	
GS 50 - 999 kW	2,953,909	7,932
GS 1000 - 4999 kW	791,396	1,669
Large User	217,139	416
USL		
Sentinel Lighting		
Street Lighting		
Total	**6,363,091**	**10,017**

4.8.6. Street Lighting

The Town of Milton and Halton Region undertook projects under the Retrofit program to retrofit streetlights with more energy efficient LED bulbs. These projects were completed after the April 2019 Participation and Cost report and are thus not captured in IESO reports. The projects were done under the prescriptive stream of the Retrofit program, which calculates energy savings based on assumed values in the IESO's Prescriptive Measures and Assumptions List. When IESO reports streetlight savings, it shows zero demand savings because streetlights are not used during peak periods. In recognition of this, the OEB sets out additional requirements for claiming street light savings in the Chapter 2 Filing Requirements, and Milton Hydro has analyzed both the energy and demand savings based on actual wattages of fixtures before and after savings, which is the basis of billing.

Calculations of Milton Hydro's lost revenues from Street Lighting are provided on Tab 8 of the LRAMVA workform. Milton Hydro is claiming only lost revenues from savings persisting to 2021 and 2022 of LED replacement program savings from 2019 and 2020 activities. Milton Hydro's 2022 LRAVMA claim for 2019 and 2020 based on these calculations was approved in Milton Hydro's 2022 IRM proceeding (EB-2021-0042).

4.8.7. Carrying Charges

In accordance with Section 13.3 of the 2012 Guidelines, Milton Hydro is seeking recovery of carrying charges up to December 31st, 2022, in the amount of $3,001. Milton Hydro used the Board's prescribed interest rates through Q1-2022. Milton Hydro has used the same prescribed rate for Q2-2022 to Q4-2022.

4.8.8. Rate Rider Calculation

Milton Hydro proposes to recover the LRAMVA amounts, including associated carrying costs, through class specific volumetric rate riders over a period of one year. These rate riders were determined by dividing the class- specific LRAMVA amount by the total billed kWh or kW for each rate class in 2020. Milton Hydro proposes a single rate rider for each rate class from January 1, 2023, to December 31, 2024. The proposed rate riders are shown in the table below.

The following tables calculates the Proposed LRAMVA Rate Riders. The Proposed LRAMVA claim has been included in the DVA Continuity Schedule model within Exhibit 9 – Deferral and Variance Accounts.

Table 4-84 LRAMVA Rate Rider

Class	Net Lost Revenues	Carrying Charges	Total LRAMVA Balance	Annual Recovery	kW/kWh	Rate Rider (2-years)
Residential					353,525,758	
GS < 50 kW	$249,188	$1,392	$250,579	$125,290	87,960,137	$0.0014
GS 50 - 999 kW	$103,950	$634	$104,584	$52,292	595,236	$0.0879
GS 1000 - 4999 kW	$51,264	$289	$51,553	$25,777	225,594	$0.1143
Large User	$24,536	$135	$24,670	$12,335	260,034	$0.0474
USL					1,067,791	
Sentinel Lighting					378	
Street Lighting	$101,404	$552	$101,956	$50,978	14,179	$3.5953
Total	**$530,341**	**$3,001**	**$533,342**	**$266,671**		

EXHIBIT 4

ATTACHMENT 4-1

BUSINESS CASE: 24/7 SYSTEM CONTROL ROOM & OPERATIONS

Overview

Milton Hydro Distribution Inc. (MHDI) services the Town of Milton, one of the fastest growing communities in Canada with 42,270 customers. To support its growing community, Milton Hydro's average fixed assets grew by $25,684,730, or 28.2% (2016 to 2023). Milton Hydro is no longer a small utility, and it needs to operate with proper systems and tools to manage its assets, customer expectations and future needs as the large utility it has become.

Since 2014, Milton Hydro has been outsourcing its control room functions to other Ontario utilities. As this arrangement no longer meets the utility's and its customers' needs and objectives, in 2021, Milton Hydro undertook a thorough strategic analysis to:

- determine the most efficient and cost effective way to operate its constantly evolving distribution system in a safe and reliable manner,
- support the capability to restore electricity as efficiently as possible,
- meet growing customer needs and expectations, and
- be future ready, including having the ability to manage the increasing number of Distributed Energy Resources (DERs).

To assist with its analysis, Milton Hydro retained a third-party expert, AESI, to undertake a feasibility study of costs and benefits of implementing an in-house control room as compared to the costs and benefits of various outsourcing and hybrid models, among other things. Based on the comparison of the size, complexity, and age of MHD's electrical system to similar utilities in Ontario, AESI concluded that MHDI is at the stage where a 24x7 control room will provide significant benefits to the utility and its customers.

Relying on its strategic objectives and needs, as further discussed in Exhibit 1, section 1.2, AESI's control room feasibility study findings and customer needs and preferences, Milton Hydro assessed the following three alternatives:

1. 24/7 in house control room;
2. In-house day-shift control room operations and on-call after hours (SCADA in operator's home);
3. Outsource 24/7 coverage.

AESI's report included cost estimates for construction and operation for each of the alternatives. Milton Hydro concluded that the most prudent alternative, yielding best results and benefits to the utility and its customers, meeting utility's objectives and customer expectations, today and in the future, is to have a 24/7 in-house system control room. Milton Hydro rejected a hybrid approach (which is Option 2 above) as it was impractical in nature and presented risks relating to employee fatigue, disengagement and burn out. The analysis of a hybrid approach also demonstrated zero cost benefit to customers. By year five, Option 1 saves approximately $100,000 or 5% in operational costs over Option 3. By Year 10, operation savings and net value to the customer is greater than $600,000.

Milton Hydro also thoroughly assessed the outsourcing option with the 24/7 coverage requirements. Milton Hydro undertook an RFP process to solicit proposals from various proponents to provide 24/7 control room coverage. Following a methodical evaluation approach to assess the received proposals, Milton Hydro concluded that none of the proponents were in a position to meet clearly defined RFP objectives and satisfy continuously growing needs of the utility and its customers.

Milton Hydro plans to construct a control room within its facilities in 2022, along with the hiring and training of two control room operators. Late in 2022, four additional operators will be recruited to start in January 2023.

Staffing a 24/7 system control room requires competent staff that understand the distribution system and its operating systems, and how to manage it all safely and in a timely manner, covering a full 168 hour week. Operators need to be fully present and engaged. Everything from ergonomics to the staffing compliment is considered to maintain a safe operational environment and healthy team. Based upon AESI's report and providing balanced coverage, Milton Hydro will build a team of six shift operators and a supervisor.

Background

In 2014, Milton Hydro contracted out its system control room functions to Guelph Hydro. The expectations were that the service would reduce power restoration times, provide for more timely after-hours outage response, save capital and OM&A costs, and support MHDI's growing, dynamic distribution system, while providing better information during outages. As Milton Hydro's capabilities grew in SCADA/OMS, real time information became available to support an outage map and twitter communications for customers. Guelph Hydro was not able to accommodate this request and Milton Hydro had to look for another service provider.

Since 2017, Milton Hydro entered into agreement with Burlington Hydro to provide control room functions. Burlington Hydro has provided control room services during regular business hours and ad hoc support after hours depending on operator availability.

Both service providers helped Milton Hydro achieve their system control room services objectives for the contracted time periods; however, a strategic review established that the current level of service would not adequately service Milton Hydro or its customers going into the future.

Areas of Strategic Consideration:

- MHDI's growing distribution infrastructure system and customer count;
- Ageing asset population;
- The increase in the number of smart devices in the field;
- Rising customer expectations;
- Enhanced safety and reliability; and
- Anticipated increase in DERs.

In less than a decade, Milton Hydro has experienced evolution from no system control room functionality to today's system and business requirements and customer expectations. The challenges are compounded when electricity's future of DERs and Distribution System Operator (DSO) functionality is considered. The review and evaluation of Burlington Hydro's current service level concluded that MHDI has outgrown its current contract service delivery model with Burlington Hydro and must look for a more robust solution.

As a result of this review, Milton Hydro engaged AESI to conduct an assessment and feasibility study as to:

1. Economic and benefit analysis to operations and customers for various system control room service delivery models;
2. Costs to construct and operate an in-house System Control Room and various operational alternatives;
3. Industry's future and need to manage DERs and operate as a DSO.

Investment Needs and Outcomes

Investment Needs

Since control room functionality was first provided, Milton Hydro's customer base has grown 20% and will continue the same growth trajectory to 2031. Milton Hydro's assets have also increased; from 2016 to 2023, average fixed assets grew by $25,684,730[1], equating to a 28.2% increase. Milton Hydro is no longer a small utility and it needs to operate with proper systems and tools to manage its assets and customer expectations as the large utility it has become.

With the capital investments planned in the 2023-2027 rate period, the complexity, capabilities and functionality of the Milton Hydro distribution system will increase with the addition of new automation equipment. It is prudent to maximize the value extracted from these investments.

As of December 31, 2021, Milton Hydro's customer count is 42,270. Table 1 identifies Milton Hydro's peers, Ontario LDCs with more than 30,000 customers and whether they have in-house system control rooms.

Table 1: Utilities with more than 30,000 Customers and In-house Control Rooms

Distributor	2020 Customer Count	In-house Control Room Y/N
Essex Powerlines Corporation	30,661	No
Sault Ste. Marie PUC Distribution Inc.	33,751	Yes
Bluewater Power Distribution Corporation	36,916	Yes
Brantford Power Inc.	40,662	No
Newmarket-Tay Power Distribution Ltd.	44,187	Yes
Greater Sudbury Hydro Inc.	47,865	Yes

[1] Fixed assets: 2016 = $88,574,495; 2023 = $113,581,019

Synergy North Corporation	56,887	Yes
Niagara Peninsula Energy Inc.	56,973	No
Waterloo North Hydro Inc.	58,438	Yes
Oshawa PUC Networks Inc.	59,486	Yes
Entegrus Powerlines Inc.	60,587	Yes
Energy+ Inc.	67,303	Yes

As can be observed from the table above, most of Milton Hydro's peers do have an in-house control room. Milton Hydro has reached a customer count whereby other utilities have an in-house system control room.

In general, across the broader general marketplace, there is a growing trend of increased customer's expectations today than previously. The electricity sector is not immune. Not only are customer expectations high with respect to having reliable electricity at their fingertips, but customer requirements will change, and the high expectations will remain the same. For example, as electric vehicle (EV) adoption increases, customers will expect that they can charge their vehicles when they want and how they want, not understanding how the increased electricity demand impacts the system's assets. Their expectation of service will remain consistent to their previous experience. A system control room will enable Milton Hydro staff to be better able to respond to issues as they arise, e.g., transformer overloading, and manage increased electricity demands with more control.

The sophistication and evolution of the electricity distribution system to smart grid and inclusion of DERs is no longer a futuristic concept – they are a real part of today's operations and an even bigger part of the future as the market and the IESO DER Roadmap moves forward. From commercial and industrial customers with large storage battery systems to residential solar installations, LDCs, like Milton Hydro, are navigating the management of utility and customer owned DERs. The volume of these installations will only increase as the market moves forward on the Federal government's GHG reduction initiatives, including Net-Zero and Net-Zero Ready building standards.

In order for the provincial grid system to be able to manage the future magnitude of electricity inputs, the system operations function must disseminate down to a regional level. This will require local LDCs to implement similarly sophisticated communications and controls currently utilized by the IESO and transmission utilities, making them regional DSOs. Additionally, distribution system operators will require a different understanding of their local grid and training. The success and stability of the future provincial grid is contingent on reliable and timely communications between the IESO and DSOs, and the DSOs having the flexibility to manage and respond to the varying customer electricity demands.

Over time, Milton Hydro's desired system control room functionality has been evolving with system and customer growth, and ageing assets. Today's consideration must also include the perspective of future needs utilizing increased automation of field assets to meet expanding customer expectations.

In AESI's experience, as the electrical system managed by the utility increases in size, complexity and age, particularly in an area with a growing population and ongoing construction and expansion, a 24/7 control room increasingly improves the efficiency and accuracy of the utility's response and provides benefits to its customers in terms of quicker resolution of outages and response to emergency calls. This is of paramount importance to ensure that Milton Hydro operates its system in a safe and reliable manner and restores power outages as efficient as possible.

An in-house system control room will increase Milton Hydro's operational resiliency, improve the utility's ability to safely operate the distribution grid delivering reliable electricity, support the capability to restore electricity as efficiently as possible, and position Milton Hydro to be 'future ready'.

Investment Outcomes

The investment outcomes from an in-house system control room can be tied back directly to the OEB Renewed Regulatory Framework for Electricity (RRFE):

- Customer Focus
- Operational Effectiveness
- Public Policy Responsiveness

- Financial Performance

Customer Focus: services are provided in a manner that responds to identified customer preferences

In the fall of 2021 Customer Engagement activities, both Residential and C&I customers strongly supported outage reductions (time and duration) and increasing reliability. In-house system control room functionality and service contribute to Milton Hydro's customer service objectives by:

- Ensuring continued capability to receive and respond to trouble calls from customers and/or external stakeholders
- Maintaining the capability to effectively manage, prioritize and resolve multiple concurrent system issues impacting customers
- Providing relevant and timely outage information to customers, such as estimated outage restoration times and other situational information relating to system outages
- Operators actively providing inputs for continuous system improvement on customer engagement processes and operational efficiency

Customer benefits from the improvement of SAIDI/CAIDI are discussed in Alternatives and Evaluation. These improvements directly relate back to having a positive impact for the customer by reducing economic losses as understood by using ICE calculations.

Customers also believe that Milton Hydro needs to invest to be 'future ready' to support their needs. Having system control room functionality will ensure that DERs can be connected and supported properly, as well as having the distribution system operate in a reliable manner, meeting the increased demand with the influx of EVs and the variable demands of net zero and net zero ready homes.

Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives

An in-house system control room will contribute to Milton Hydro's reliability objectives (e.g., SAIDI, SAIFI) by:

- Reducing the likelihood of a complete or partial stand-down of planned and unplanned field work and the likelihood of cascading outages resulting from interruption to visibility over the distribution system
- Ensuring compliance with requirements relating to system restoration planning outlined in Chapter 5, Section 11 of the IESO's Market Rules

An in-house system control room will contribute to Milton Hydro's safety objectives by:

- Providing seamless visibility over the distribution system, thereby reducing the likelihood of worker/public injury resulting from loading issues and inadvertent energizing of equipment
- Ensuring efficient administration and application of the Utility Work Protection Code (UWPC)
- Maintaining compliance with Ontario Regulation 22/04 (Electrical Distribution Safety) through timely reporting of serious electrical incidents involving Milton Hydro plant.

Public Policy Responsiveness: utilities deliver on obligations mandated by government

An in-house system control room will contribute to Milton Hydro's public policy objectives by consistently meeting OEB-mandated service quality targets with respect to Emergency Response (Distribution System Code, s. 7.9).

With stakeholder input, the IESO developed and has published the DER Roadmap that sets out goals, objectives, initiatives and timing for DER integration into electricity markets. The integration activities planned from now until 2026 will address the challenges and opportunities in three key areas: wholesale market integration, transmission-distribution coordination and enabling non-wires alternatives. An in-house system control room will enable Milton Hydro to participate in this 'new' electricity market.

Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable

The long-term financial viability of an in-house control room is discussed in the Alternatives and Evaluation.

Investment Description

System Control Room

Within Milton Hydro's office at 200 Chisholm Dr, there is space that can accommodate a system control room. AESI reviewed and assessed the space and concluded that it is suitable for control room operations. AESI prepared a simplified drawing of the proposed control room layout, with areas for two operator consoles and a war room with a supervisor's desk and a long table for holding SCADA/OMS workstations and discussions. The system control room would operate 24/7 with six operators and a supervisor.

In 2022, Milton Hydro will establish a system control room with the construction of new control room office space and a control room war room. Milton Hydro will issue an RFP to select appropriate vendors to complete the work.

The space is approximately 12 meters by 10 meters and would be divided into two rooms: system control room and war room, both would have fire suppression facilities. The system control room would have controlled access, along with HVAC and lighting controls and is large enough for two operator consoles. The war room would house the supervisor's area and a large multi-purpose table and chairs. Located at one end of the table will be three SCADA/OMS view only workstations and monitors. There is also space designated for the placing and pinning paper maps in each room. Additional details are outlined in AESI's report.

Until the new facilities are constructed, Milton Hydro will use a temporary location to house its control room equipment and staffing compliment.

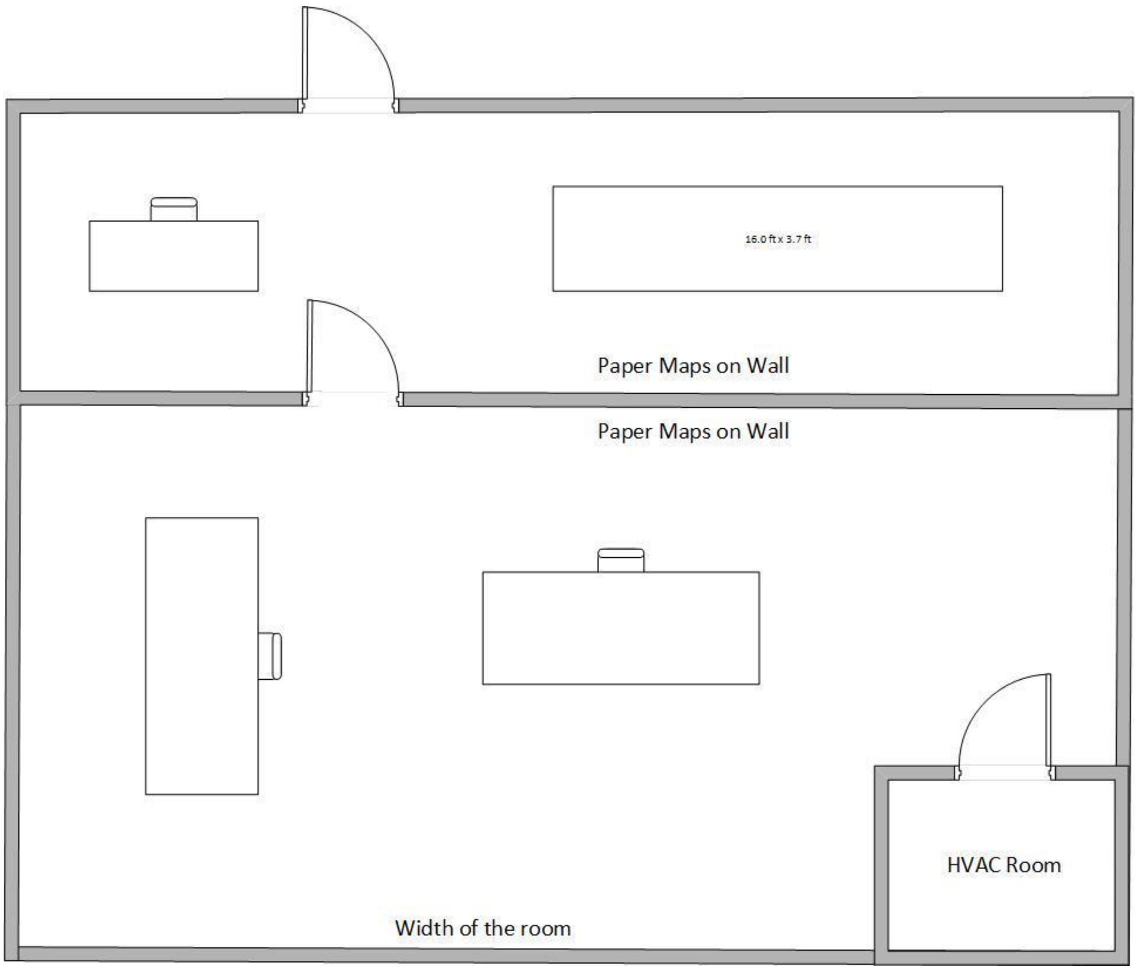

Figure 1: Basic control room layout.

Staffing

A system control room is a complex, fast paced environment that requires constant vigilance to be able to monitor, identify alerts and respond in a timely and safe manner with consistent and fluid communications. To support operators in a demanding and unpredictable environment, great effort goes into creating an ergonomic and operator-centric environment from lighting and operational workflow that will facilitate ease of movement across activities of different screens and operating systems and maps and desks.

The same consideration must be given to the level of staff so that the system control room operators are engaged and alert and the system operations has proper coverage at all times.

There needs to be adequate resources to properly deliver 24/7 coverage without employee fatigue, disengagement or burn out.

AESI presented various staffing scenarios. Milton Hydro's consideration focuses on maintaining a safe operations environment and positive and healthy team. The staffing compliment must take into consideration of a full 168 hour week, training and vacation time, times of additional need (large outage events or switching orders), and supervision/ management.

Utilities that reach the need to have a 24/7 control room typically have enough maintenance, construction, and disconnects/reconnects to warrant two operators during business hours (when the majority of this activity occurs) and one operator outside of business hours (i.e., night shift and weekends) when the system is typically less busy. This schedule is typically covered by six operators and one supervisor.

There are many approaches for scheduling the six operators, however they all center around the following concepts:

1. Ensuring there is always at least one operator on desk.
2. Ensuring there are two operators on desk during busy times – typically during business hours.
3. Having spare operators to cover vacations, training, etc.
4. Ensuring that each operator averages out to around 40 hours per week over the course of the year.

Based upon AESI's report and Milton Hydro's needs and objectives, the utility will build a cohesive team of six shift operators and a supervisor. Milton Hydro will hire two system control room operators in the fall of 2022, and then train them on the distribution grid and infrastructure, the outage management system, operating procedures, etc. Milton Hydro will use Lean Six Sigma methodology to develop new control room operating procedures for best-in-class efficient processes. Milton Hydro plans on commencing recruitment for the remaining four system control room operators in the fourth quarter of 2022, with a January 2023 start date.

Investment Costs

System Control Room

As part of AESI's report, they developed a detailed quote as to the costs to construct and commission a system control room. AESI assessed similarly sized utility system control rooms.

General requirements for building renovations and requirements for software, hardware, communications equipment, and technical specifications were considered.

AESI issued a specification to build a control room, as previously described, to Black and MacDonald, who is familiar with MHDI's building. They also requested a budgetary quote from Tresco for two standard consoles. AESI prepared an estimate for the remaining items that would be included in the overall cost of the control room.

The capital costs* for establishing the system control room ready for use are summarized as follows:

Table 2: System Control Room Investment Costs

Control Room Construction	$352,000
Operator consoles (including delivery and installation)	$70,000
Fire Suppression Installation	$20,000
Furniture, additional workstations, phones, radio, cables	$25,000
Adequate Resiliency and Cyber Security	$45,000
Total	$512, 000

* costs do not include applicable taxes

In 2022, Milton Hydro will invest $512,000 to build and furnish its system control room in the [redacted]

Staff

The staffing costs are based upon an operator's annual salary at $109,000 and fully burden rate of $212,550. The total annual cost for six operators and a supervisor is $1,479,675.

Additional Costs

Additional costs for networking costs for redundancy and resiliency, and operations of the control room equipment total $53,300 per year

Table 3: Total Annual Operating costs

Six operators and a supervisor	$1,532,975
Other costs	$53,300
Total	$1,586,275

Risks

If an in-house control room investment is not made at this time, Milton Hydro runs the risk of:

- Investing money in out-sourced solutions that build no internal capacity
- Having to make the investment in future, at a greater expense
- Not being able to respond as quickly or easily to customers' changing demands
- Not being able to respond to customers' requests for DER support
- Can potentially increase risk of exposing workers and public to unsafe electrical conditions by not having dedicated monitoring and control resources for its dynamically changing system
- Not investing in continual Operator feedback for system flexibility and efficiency

Alternatives and Evaluations

On behalf of Milton Hydro, AESI completed an economic and benefit analysis, considering multiple scenarios for both outsourcing and an in-house system control room, response efficiency, customer loss savings and tangible and intangible benefit analysis for MHD, staff and customers.

AESI presented five options:

1. 24/7 in house
2. Two operators at 36 hours each plus on call
3. Outsource 24-7 coverage
4. In house 5/8 and outsource after hours
5. In house 5/8 + storm call in + on call with field crews on call 86h

The report includes a sixth alternative: the outsource business hours; after hours as required, which is the current SLA for a based line comparison.

AESI's Option 2 and Option 5 were eliminated from Milton Hydro's evaluation. Upon examination and future consideration of longer-term viability, Milton Hydro realized the proposed team structures for these two options were too lean to be sustainable. The likelihood of operator burnout and disengagement was high for critical roles.

Option 1, Option 3 and Option 4 were carried forward for a more detailed analysis.

To properly assess the outsourcing alternative, Milton Hydro issued an RFP for an updated SLA based upon the drivers identified in the Investment Needs and the requirement for 24/7 coverage. Other alternatives were identified in the RFP. The RFP was issued to three utilities: Burlington Hydro, Oakville Hydro and Oshawa Hydro. The SLA outlined Milton Hydro's expectations as to:

- Operator commitment
- Number of SCADA/OMS console desks
- How each SCADA/OMS workstation and operator would be outfitted with the appropriate hardware, communication connects, equipment, operator logs, etc.
- Additional provisions necessary for operators to function effectively
- Specific KPIs for safety, outages, trouble calls, reclosers, working with field crew, monitoring SCADA, maintenance, prepare order to operate/work permit and maintaining operator log

The responses were evaluated using a prescribed methodology with pass/fail thresholds, weighted criteria and scoring (1-10). Information was extracted from this process to build and evaluate the presented alternatives.

Consideration for dedicated operators is valued by Milton Hydro – faster response times will be enabled from immediate proximity to the operating systems and sole focus to the MHDI grid, as well as better knowledge of the distribution system and familiarity with the OMS interface. Knowledge of the distribution system and field devices also enables better communication, direction and safety for the field crews.

Alternatives

Alternative 1 is the complete in-house servicing of the system control room functionality, with 24/7 operator coverage support.

Alternative 2 is a combination of Milton Hydro providing day shift operator coverage in-house, and out-sourcing after hours and weekends.

Alternative 3 is the complete outsourcing of the system control room functionality, with 24/7 operator coverage support.

Alternative Evaluations

AESI used the Interruption Cost Estimate (ICE) Calculator[2] to calculate cost savings based on improved SAIDI/SAIFI/CAIDI numbers; improvements of 10%, 15%, 20% and 25% were calculated. The ICE calculations with the SAIDI/CAIDI improvements were applied to various service coverage alternatives. The 24/7 coverage assumed a 20% average improvement for most lengthy faults.

Table 4: ICE Calculations

Alternatives	Improvement in SAIDI/CAIDI over Current Service Level	Potential Annual Average Savings
1. 24/7 in house	29.70%	$1,235,000
2. In house 5/8 and outsource after hours	-15.26%	<$0
3. Outsource 24-7 coverage	29.70%	$1,235,000

Using the ICE calculations, the two alternatives that net the highest benefit for customers are Alternatives 1 and 3.

[22] The ICE Calculator is a tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements. It is funded by the Energy Resilience Division of the U.S. Department of Energy's Office of Electricity (OE) under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Table 5: Comparison of Cumulative Costs* over 5 years

Alternatives	One Time Cost	Annual Staffing Cost	Year 1 total	Year 2 total	Year 3 total	Year 4 total	Year 5 total	Year 10
1. 24/7 in house	$512,000	$1,532,975	$2,044,975	$3,577,950	$5,110,925	$6,643,900	$8,176,875	$15,841,750
2. In-House Day, Outsourced After Hours	$555,500	$774,000	$1,329,500	$2,103,500	$2,877,500	$3,651,500	$4,425,500	$8,295,500
3. Outsourced 24-7 coverage	$117,500	$1,633,100	$1,750,600	$3,383,700	$5,016,800	$6,649,900	$8,283,000	$16,448,500

* The presented costs are drawn from AESI’s report and not actual costs received from the RFP process.

Table 6: Comparison of Cumulative Costs and Savings

	Option 1: 24/7 in house	Option 2: In-House Day, Outsourced After Hours	Option 3: Outsourced 24-7 coverage
One Time Costs	$512,000.00	$555,500.00	$117,500.00
Annual Costs	$1,532,975.00	$774,000.00	$1,633,100.00
Potential Annual Customer Benefit	$1,235,064.39	$0	$1,235,064.39
Net Year 1	**($809,910.61)**	**($1,329,500.00)**	**($515,535.61)**
Cumulative Cost 5 Years	$8,176,875.00	$4,425,500.00	$8,283,000.00
Cumulative Savings 5 Years	$6,175,321.95	$0	$6,175,321.95
Net Year 5	**($2,001,553.05)**	**($4,425,500.00)**	**($2,107,678.05)**
Cumulative Cost 10 Years	$15,841,750.00	$8,295,500.00	$16,448,500.00
Cumulative Savings 10 Years	$12,350,643.90	$0	$12,350,643.90
Net Year 10	**($3,491,106.10)**	**($8,295,500.00)**	**($4,097,856.10)**

The sheer loss of any Potential Annual Customer Benefit with Option 2 quickly eliminates Option 2 as a sustainable proposition to achieve and deliver Customer value.

By year 5, the total costs between the Option 1 and 3 is less than 1% and by Year 10, operation savings and net value to the customer is greater than $600,000.

Alternative 1: In-house 24/7 Control Room Services

Milton Hydro will be able to ensure dedicated operators for the full 168 hour week to provide the desired level of service.

Milton Hydro customers and staff achieve maximum benefit from system control room functionality and services.

This solution builds and sustains in-house capacity.

Alternative 2: In-House Day, Outsource After Hours

Milton Hydro will be able to guarantee dedicated operators five days a week, eight hours a day. The desired outcomes from dedicated operators will be achieved, but this accounts for less than 25% of the 168 hour week.

It is highly unlikely to be able to retain system control room services with the desired dedicated resources for after hours and weekend.

There are no Potential Annual Customer Benefit to be derived by Milton Hydro customers with Alternative 2.

This solution builds in-house capacity.

Alternative 3: RFP for outsourcing 24/7 System Control Room Services

Assuming this coverage is provided by dedicated operators, Milton Hydro customers and staff achieve maximum benefit from system control room functionality and services.

If this coverage is not provided by dedicated operators, the derived benefits decrease.

This solution does not build any in-house capacity.

The long-term ROI is not cost effective as Alternative 1.

EXHIBIT 4

ATTACHMENT 4-2

AESI REPORT - CONTROL ROOM COST BENEFIT ANALYSIS

Milton Hydro Distribution

Control Room Cost Benefit Analysis

Milton Hydro Distribution (MHD) contracted AESI to complete a study of the costs and benefits of implementing an in-house control room as compared to the costs and benefits of various outsourcing models. The study estimates the cost of constructing and operating an in-house control room and compares it to the costs of outsourcing the control room function, as well as several hybrid alternatives. The study also explores the potential benefits of each option and ranks the options in terms of the degree of benefit they are likely to provide.

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APPENDIX LISTING

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1. Executive Summary

Milton Hydro Distribution (MHD) contracted AESI to complete a study of the costs and benefits of implementing an in-house control room as compared to the costs and benefits of various outsourcing models. The study estimates the cost of constructing and operating an in-house control room and compares it to the costs of outsourcing the control room function, as well as several hybrid alternatives. The study also explores the potential benefits of each option and ranks the options in terms of the degree of benefit they are likely to provide.

Based on a comparison of the size, complexity, and age of MHD's electrical system to similar utilities in Ontario, MHD is at the stage where a 24x7 control room will provide significant benefits to MHD and their customers. Based on our utility experience, a 24x7 control room requires six operators and a supervisor to ensure proper coverage throughout the week, particularly during business hours when dealing with large amounts of construction and coordinating with field crews.

AESI reviewed MHD's current facilities and systems, and identified the renovations and upgrades required to implement an in-house control room and estimated the initial costs at approximately $0.5M. Similarly, AESI conducted a salary survey and identified the ongoing costs required to operate an 24x7 in-house control room and estimated annual costs at approximately $1.5M assuming a full complement of six operators and one supervisor.

AESI examined five other options using different in-house, outsourced, and hybrid staffing models, compared their initial and annual costs to the in-house 24x7 option, and attempted to quantify the level of economic benefit of each alternative to MHD and their customers over a ten-year period.

AESI determined that the greatest quantifiable economic benefit is related to large customer loss reductions due to shorter durations of outages, with the greatest benefit (approximately $1.2M annually) offered by control rooms staffed 24x7, whether in-house or outsourced. Control rooms staffed during business hours demonstrated no discernible improvement in this area. A comparison of the costs of both in-house and outsourced 24x7 control rooms showed that an in-house control room becomes more cost effective within four years of implementation.

AESI also examined a number of qualitative benefits, such as the flexibility to adapt to the rapidly changing nature of the electric grid, improved situational awareness, communications with field crews, upper management, and the public, consistent safety, and improved utilization of tools and distribution automation, all of which benefit most from an in-house control room with staff dedicated to learning the nuances and optimizing the operation of MHD's distribution system.

AESI also examined the current industry direction and future benefits provided by an in-house control room. As the electric grid becomes more complex due to added automation, greater penetration of distributed energy resources (DER), and the creation of distribution system operators (DSO), MHD will need to deploy more sophisticated tools which will require a flexible and capable work force. Dedicated MHD operators will be able to spend more time learning and perfecting their use of these tools without having to divide their time between MHD and other utilities' systems as outsourced operators would need to do and should therefore provide greater benefits to MHD and their customers in the long run.

In particular, an in-house control room will enable MHD to become a DSO and capitalize on potential benefits such as supply diversity and optimization, energy cost reduction, and new revenue streams.

2. Objectives

The objective of this study is to provide Milton Hydro Distribution (MHD) with an expert analysis of the costs and benefits of an in-house control room as compared to full or partial outsourcing of the control room function. To that end, this report examines:

1. The costs to construct and operate an in-house control room
2. The costs of various outsourcing alternatives
3. Immediate benefits of an in-house control room to both MHD and their customers
4. Potential future benefits of an in-house control room given current industry trends

3. Findings

3.1. Construction and Operating Costs

In order to identify the costs associated with constructing and operating an in-house control room, AESI completed the following activities:

- Reviewed system control room solutions at similarly sized electric utility clients
- Reviewed the MHD building and identified renovations required for implementing an in-house control room
- Reviewed the current state of software, hardware, and communications equipment and identified the technical specifications for all aspects of the control room
- Developed high level budgetary cost estimates for:
    - The construction and commissioning of the control room, including costs to improve the resiliency and cyber security to an appropriate level
    - The ongoing operating costs of a 24x7 control room as well as alternative options such as an 8x5 business hours only control room

3.1.1. Peer Utility Control Room Review

Since 1984, AESI has assisted many electrical utilities of various types and sizes with the implementation of control rooms and the associated systems and processes. We continue to assist utilities with the implementation of advanced tools in response to trends in the industry such as the shift to distributed energy resources, realization of energy/cost savings through demand response and volt/var optimization, and improved reliability and customer experience through tools such as outage management, fault location isolation service restoration (FLISR), etc. Our staff come from the industry and have extensive experience in implementing and operating 24x7 control centers.

Through our connections with industry associations and individual utilities across North America and abroad, we continue to research and present on the transformation of the electric industry, and the tools and processes required to implement and operate the sustainable grid of the future.[1]

AESI utilized our extensive experience and expertise in implementing, operating, and upgrading control rooms to compare MHD's current and likely future state to other distribution utilities and identify:

- The typical evolution of the utilization of a control room by a distribution utility and where MHD lies on that path

[1] Ganton, D.R. (2020). *A Roadmap to the Sustainable Grid.* EDIST 2020, Markham, ON, Canada

- The staffing required based on the state/scale of the utility and its operating environment and where MHD fits on that scale
- The facilities required for a control room of a distribution utility of MHD's size and complexity

Control Room Utilization

In AESI's experience, an electric distribution utility's need to utilize a control room and the related Supervisory Control and Data Acquisition (SCADA) system are related to the following factors:

- **Size and complexity of the distribution system** – larger, more complex systems benefit from a dedicated operator who can monitor and control the entire system; large enough systems require multiple operators
- **Age of the distribution system** – older systems tend to have more equipment failures which require replacement or repair
- **Amount of construction in the area** – increased construction requires centralized coordination of field crews, outage planning, etc.
- **The number and type of customer served** – larger populations lead to increased number of accidents, fires, etc. which require utility coordination with emergency services; large numbers of industrial customers benefit more from the reduced outages a control room provides
- **Advanced tools deployed by the utility –** although they improve various aspects of the operation of a distribution system, advanced distribution management system (ADMS) tools such as outage management systems (OMS), advanced metering infrastructure (AMI), powerflow, FLISR, volt/var optimization, etc. require monitoring and management by a human operator; more tools require more time, which requires more than one operator on shift
- **Penetration of distributed energy resources (DER) and electric vehicles (EV)** – DER and EV add to the complexity of the system as they create new source of energy which need to be monitored and managed

Utility usage of SCADA and a control room typically evolves as each of the factors above increases:

- Very small utility, simple system, minimal construction:
  - SCADA is used occasionally to monitor the system and alarm breaker trips
  - No control room exists, no operators are required
  - Substation/line staff use SCADA workstation to identify which breaker caused an outage
  - Trouble calls from customers are directed to an on-call field crew
- Small utility, simple system, some intermittent load growth and related construction:
  - Small control room staffed during business hours (8x5) to interact with field crews and monitor system
  - After hours breaker trips page or email on-call operator who informs field crew and drives to control room to monitor the system and assist with restoration
  - Trouble calls from customers are still directed to an on-call field crew
- Medium utility, more complex system, continuous construction, older core infrastructure:
  - Multiple field crews required to deal with construction and increased number of trouble calls/failures

  - Field crews require direction/instructions based on accurate understanding of system state
  - Increased requirement to monitor SCADA, work with field crews, and create more switch orders
  - Control room staffed for two eight hour shifts on weekdays (16x5), or all week (16x7) for areas with larger populations, manufacturing sector customers, and more weekend trouble calls
  - Summer storms which occur late in the evening or overnight drive the need for overtime
  - The increased hours, storm restoration overtime, vacations, and training require up to four operators or three operators and a supervisor who can cover shifts if needed
- Larger utility, complex aging system, continuous construction, increased trouble calls, increased field automation, smart metering, and large numbers of distributed energy resources (DER) and electric vehicles (EV):
  - Additional ADMS tools deployed to manage and track the more complex system
  - Control room staffed 24x7 to accommodate the additional complexity, construction, trouble calls, etc. and to manage the new tools

Although there is no formula to determine exactly when to move from a SCADA supported field crew to a control room staffed during business hours and from there to a 24x7 staffed control room, it is AESI's experience that as the electrical system managed by the utility increases in size, complexity and age, particularly in an area with a large population and ongoing construction and expansion, a 24x7 control room increasingly improves the efficiency and accuracy of the utility's response and provides benefits to its customers in terms of quicker resolution of outages and response to emergency calls.

Based on a comparison of the size, complexity, and age of MHD's electrical system to similar utilities in Ontario (e.g., Burlington Hydro, Oshawa Power, and Oakville Hydro), AESI is of the opinion that MHD is at the stage where a 24x7 control room will provide significant benefits to MHD's customers. AESI notes that MHD operates a distribution system that has the same or greater size and complexity as those of the above utilities had when they implemented a 24x7 control room.

Control Room Staffing Requirements

Control room staffing requirements are based on:

- Control room utilization – i.e., how many hours will a control room be utilized, and on which days (e.g., 8x5, 12x5, 16x5, 16x7, 24x7, etc.)
- Typical amount of work throughout different times of day and different days of the week
- Availability of other staff (e.g., supervisors) to assist in operating when required
- Amount of vacation and training that needs to be accommodated
- Willingness of operators to work overtime
- Ability to respond remotely after hours (remote SCADA)

The following are typical staffing requirements/considerations based on various combinations of the parameters above:

- 8x5 (business hours only):
  - One operator + designated alternate for vacations, training, sick time, etc.
  - Overtime for outages and trouble calls

- 12x7 (one twelve-hour shift, seven days per week):
    - Two operators alternating
    - Overtime for outages and trouble calls potentially reduced due to longer shifts
    - Some need for designated alternate for vacations and training
- 16x7 (two eight-hour shifts, seven days per week):
    - Minimum of three operators on rotating shifts
    - Fourth operator to cover vacation and training
    - Further reduction in overtime for outage and trouble calls
    - Four people typically require a supervisor
- 24x7 (at least one operator on shift at all times):
    - Two twelve-hour shifts or three eight-hour shifts per day
    - Theoretically possible with four operators, but leaves no time for vacation or training
    - Six operators is typical to accommodate vacations, training, and times when a second operator is required to deal with switching and field crews
    - Supervisor typically required

Utilities which reach the need to have a 24x7 control room typically have enough maintenance, construction, and disconnects/reconnects to warrant two operators during business hours (when the majority of this activity occurs) and one operator outside of business hours (i.e., night shift and weekends) when the system is typically less busy). This schedule is typically covered by six operators and one supervisor.

This report analyses the 24x7 scenario with six operators and a supervisor, and the 12x7 scenario with two operators.

Control Room Facility Requirements

Each operator on shift requires their own operator console. Unlike regular desks, consoles are designed to accommodate multiple monitors, keyboards, and mice in an ergonomic manner with 24x7 operations in mind. Since a 24x7 control room typically has two operators on shift during business hours, two operator consoles are required. Typically, the second console will also be used during large outages, and it provides a backup in the event the primary console has a failure.

Each operator console needs to accommodate:

- At least three large monitors connected to the SCADA system, as monitoring the system requires having multiple displays visible at the same time (e.g., alarms, schematics, OMS, etc.)
- A fourth display connected to a corporate computer (i.e., not SCADA) for activities such as viewing email, documents, weather forecasts and radar, and detailed geographical information system (GIS) maps
- Separate keyboard and mouse facilities for SCADA and the corporate computer, as switching one keyboard/mouse between the two leads to delays and errors.
- A phone with a wireless headset tied to the emergency number
- A radio handset for communicating with field crews, with an optional cell-phone as backup
- A paper operator log and potentially other documents without impeding access to the computers, phone, or radio

The control room needs to accommodate:

- Either large video displays or large paper maps for displaying large overviews of the electrical system with the ability to show normal and/or current status of field devices
- Facilities for meeting with field crews to lay out drawings for discussion and planning of operations

Due to the 24x7 nature of control room operations, the operators will require a bathroom and kitchen which are nearby and easily accessible from the control room. The maximum acceptable distance between these facilities and the control room depends on whether there are multiple operators on shift and whether the operator can monitor the phone and/or system while away from the control room.

Control rooms also require uninterruptible power supplies (UPS) and generator backup so they can continue to function during power outages, lighting suitable for long periods of watching computer monitors as well as reviewing paper documents, environmental controls to ensure the comfort of the operators, and security controls to prevent unauthorized access.

3.1.2. Building Renovation Requirements

Based on a site visit to MHD and discussions with MHD staff, AESI identified a suitable room in the existing MHD building which could be sub-divided and otherwise renovated to accommodate a control room. Based on the review of the existing room and the general control room requirements AESI identified the following modifications required convert the existing room:

1. Walls and drop ceiling to sub-divide the space and create a control room, war/meeting room, and heating, ventilation, and air conditioning (HVAC) room
2. Doors to each of the rooms; access controls on the control room door
3. HVAC facilities to control the environment in the new rooms
4. Fire suppression equipment
5. Lighting suitable for a control room
6. Two operator consoles
7. Paper maps in both control room and war room
8. UPS circuits for lights and consoles
9. Meeting room table and supervisor desk for war room

Figure 1 shows the proposed layout of the control room and war room. Appendix A contains more detailed requirements for the control room, Appendix B contains more detailed requirements for the operator consoles.

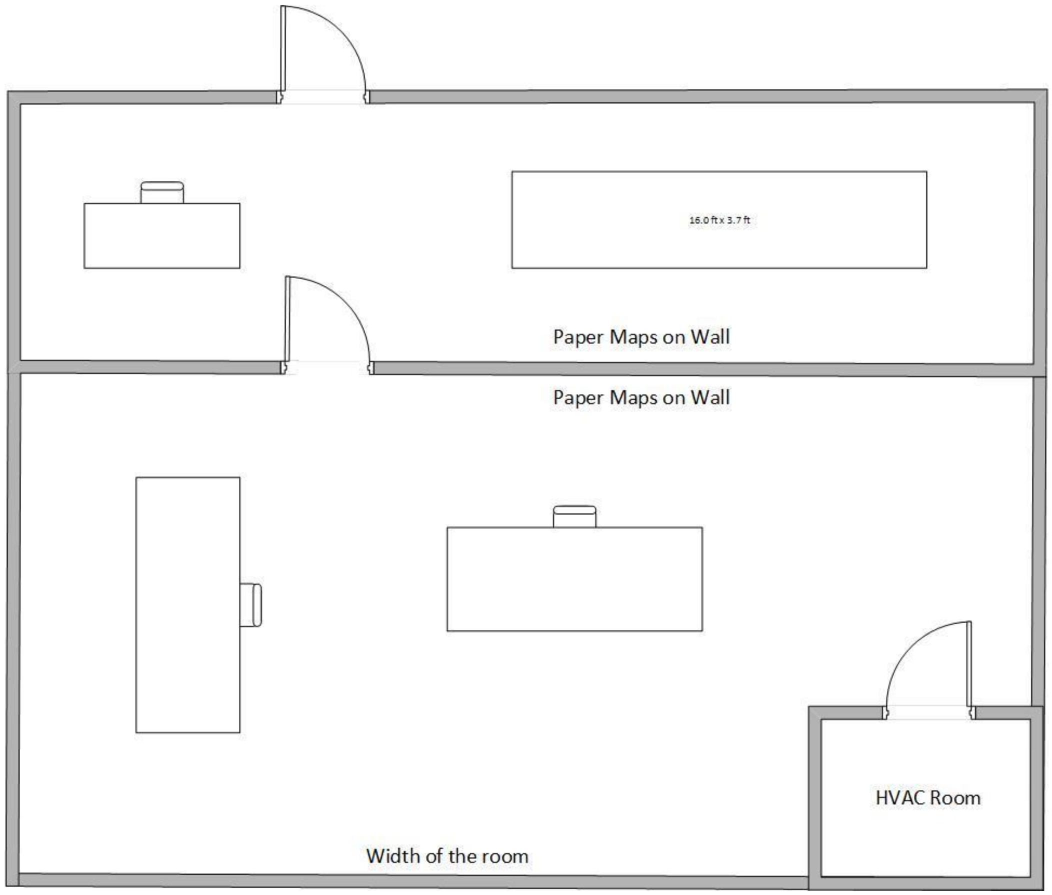


Figure 1: Proposed Control Room Layout

3.1.3. Hardware, Software, and Communications Requirements

In addition to the renovation requirements identified in section 3.1.2, AESI reviewed existing MHD control room related hardware, software, and communications to identify high level costs related to these items. Our estimate of these costs is based on the following observations:

1. Existing SCADA workstations and software, currently located at the control room service provider's site, still has sufficient useful life and will be reused in the in-house control room
2. Only if a combination of an in-house business control room with off-business hours outsourcing is chosen, will new workstation hardware need to be supplied to either the control room or the outsourcer, but not both.
3. Six standard MHD corporate IT computers and monitors will be required: one per operator console, one for supervisor desk, three for war room table. No additional licensing is required for SCADA view only licenses.
4. New cables from the server room to the control room will be installed by MHD IT.
5. Three phones with wireless headsets (one per operator console plus one for supervisor) will be installed and configured by MHD IT personnel.
6. One printer/fax will be installed on the primary operator console by MHD IT personnel
7. No additional labour costs required for items installed by MHD IT – i.e., corporate computers, cabling, phones, printer; material costs for cabling, phones, and printer are negligible.

8. Radio costs will include three handsets on operator and supervisor desks and cabling to an external antenna to counteract signal attenuation by the building envelope.
9. Three ergonomic chairs designed for long shifts will need to purchased.

The costs of the above have been included in the overall cost estimate.

3.1.4. Resiliency and Cyber Security Requirements

AESI reviewed network diagrams of MHD's current SCADA system, the associated communications, and supporting IT/OT systems and conducted interviews with MHD staff to understand MHD's current level of redundancy/resilience, cyber security posture and system management practices. AESI compared MHD's systems and practices to industry best practices for similarly sized utilities and identified areas which require changes or upgrades to provide an appropriate level of redundancy, resiliency, and cyber security to support a 24x7 control centre.

Redundancy and Resiliency

Table 1 outlines the changes/upgrades required to achieve an appropriate level of redundancy and resiliency to support a 24x7 control centre as well as the related costs. The costs are based on the following observations:

1. The existing SCADA servers have an adequate level of hardware redundancy; failover capability can be improved via software configuration.
2. Existing SCADA network switches are past end-of-support and cannot be stacked to improve network redundancy.
3. Existing SCADA firewall is close to end-of-support and is not redundant.
4. MHD has the necessary rack space at their existing disaster recovery (DR) site to accommodate the equipment required for a SCADA DR.
5. Moving one of the existing SCADA servers to the DR site is consistent with configurations for similarly sized distribution utilities in Ontario.
6. Existing workstations will be used at the primary control center. Laptops can be used for monitoring/controlling SCADA in a DR scenario. Longer term operation from the DR site may require an agreement to use one of the DR site's meeting rooms as a temporary control room.
7. The Wide Area Network (WAN) at the primary control centre should be redundant. Due to the location of the primary control centre, a wireless WAN is the most cost effective and provides a reasonable level of redundancy.
8. The existing Inter-control Centre Communications Protocol (ICCP) connection relies on multiple third parties and should be replaced by dedicated ICCP connection with Hydro One; the DR site should implement a similar ICCP connection.
9. Current backups as described by MHD staff are adequate.
10. The DR site provider's WAN connection can be used for field communications at the DR site. This may require an agreement with the DR site provider ahead of time.

Table 1: Required Redundancy/Resiliency Costs

Affected Component	Change Description	Initial Costs	Annual Costs
SCADA Server Components	Enable network card teaming	$0	$0
SCADA Network Switches	Replace switches with supported redundant switch stack	$8,000	$400

	Add redundant switch stack to DR site	$8,000	$400
SCADA Firewalls	Replace firewall with supported redundant firewall pair with 24x7 support	$8,500	$2,000
	Add redundant firewall pair with 24x7 support to DR site	$8,500	$2,000
SCADA Servers	Move one SCADA server to existing DR site	$0	$0
SCADA Workstations	Move existing workstations to new control room	$0	$0
	Add 2 laptops for DR workstations	$5,000	$300
Field Communications	Add redundant WAN at Milton office	$1,600	$25,000
Hydro One Communications (ICCP)	Replace current shared ICCP connection with dedicated ICCP connection	$1,500	$9,500
	Add dedicated ICCP connection at DR site	$1,500	$9,500
Backups	No changes required	$0	$0
Disaster Recovery Site	Use existing IT DR site for DR location	$0	$0
Radios	Add two radios for operators	$2,400	$0
Total Costs		**$45,000**	**$49,100**

Table 2 identifies the initial and ongoing costs associated with two optional upgrades which would further improve resiliency and redundancy:

1. A backup fibre WAN connection in lieu of the wireless option identified above
2. A third SCADA server to allow for a redundant pair at the primary site and a single server at the DR site

The backup fibre WAN would provide higher bandwidth and better immunity to weather, electronic interference, potential congestion on cellular towers, etc.

The third SCADA server would provide additional flexibility for testing changes without needing to fail over to the backup site and would maintain the current local level of redundancy while adding geographically diverse redundancy.

Table 2: Optional Redundancy/Resiliency Costs

Affected Component	Change Description	Initial Costs	Annual Costs
SCADA Servers	Add third SCADA server to existing DR site	$4,000	$500
	Purchase additional license for third SCADA server	$52,000	$16,000
Field Communications	Add redundant optical fibre WAN at Milton office	$125,000	$25,000
Total Costs		**$181,000**	**$31,500**

Cyber Security

AESI reviewed MHD's latest report to the Ontario Energy Board regarding their compliance with the Ontario Cyber Security Framework (OECF) based on MHD's current risk profile, and reviewed MHD's implementation of key controls related to the implementation of the framework and determined that:

1. MHD's risk profile viz-a-vis the OECF does not change with the addition of a control room.
2. The current implementation is largely adequate to meet the intent of the OECF.
3. MHD could implement minor improvements to the controls, but these do not require investment in additional technology or services

Based on the above, no additional cyber security related costs are included in the cost estimate.

3.1.5. Construction and Commissioning Costs

AESI prepared a specification for the renovations based on the control room requirements in section 3.1.2, and obtained a budgetary quote from Black and McDonald. Black and MacDonald was selected as a reputable firm who has completed similar control room related renovations and is also familiar with MHD's building, having done work for MHD in the past. The specification provided to Black and MacDonald is included in Appendix A and the budgetary quote based on the specification is included in Appendix C

AESI requested a budgetary quote from Tresco consoles, a reputable provider of operator consoles for the utility industry, for two typical consoles as described in Appendix B. This quote is included in Appendix D.

Table 3 contains a summary of the costs to construct and equip a control room based on the provided quotes, the resiliency and cyber security costs in section 3.1.4, and AESI estimates of the remaining costs, based on our work on similar projects. The costs do not include applicable taxes.

Table 3: Summary of Construction and Equipment Costs

Expense	Cost
Control room construction	$352,000
Operator Consoles	$70,000
Fire Suppression	$20,000
Furniture, additional workstations, phones, radios, cabling	$25,000
Resiliency and Cyber Security	$45,000
Total Cost	**$512,000**

3.1.6. Operating Costs

There three categories of costs for operating a control room:

1. Staffing – i.e., the fully burdened costs of the operators and supervisor, including salaries, benefits, pension, overtime, training costs, etc.
2. Support costs for any new equipment and recurring WAN costs
3. Electricity costs to operate the control room

The vast majority of the operating costs come from staffing; the percentage obviously varies with the number of staff, but for a 24x7 control room with six operators and one supervisor, staffing makes up over 95% of the operating costs.

Staffing Costs

Since MHD does not have any operators on which to base the salary, AESI conducted a salary survey of operators at similar utilities using publicly available sources to arrive at an appropriate estimate. See Appendix E for details of the survey. Based on discussions with MHD, the fully burdened costs of an MHD operator are approximately 1.95 times their salary. This is consistent with other AESI utility clients.

Based on AESI's experience, the salary of a supervisor was estimated to be 1.25 times the salary of an operator. Supervisors are typically not paid overtime, so the burdened cost should be lower than that of an operator and was estimated at 1.5 the salary.

Table 4 shows the annual staffing costs based on the output of the salary survey, the multipliers above, and the number of operators and supervisors.

Table 4: Annual Salary and Burden Totals

Operator Salary	Burdened Cost per Operator	Burdened Cost for Two Operators	Burdened Cost for Six Operators	Burdened Cost for Six Operators and Supervisor
$109,000	$212,550	$425,100	$1,275,300	$1,479,675

Other Operating Costs

Other operating costs include the new support contract costs and recurring WAN costs identified in section 3.1.4 as $49,100, and the additional electrical consumption of running the HVAC equipment, lights, and computer equipment associated with the control room, estimated by AESI at $4,200 per year, for a total non-staffing annual cost of $53,300.

In-house and Outsourced Staffing Options

This report explores the relative costs and benefits of six staffing options: three fully in-house, two fully outsourced, and one hybrid. The options are outlined in Table 5 and explored in more detail in the following sections.

Table 5: Staffing Options

Option Name	Option Type	Notes
Option A: 24x7 In-house	In-house	Minimum six operators plus supervisor
Option B: 12x7 In-house	In-house	Two operators alternating 12-hour shifts On-call with remote SCADA for afterhours outages
Alternative 1: 8x5 Outsourcing	Outsourced	Dedicated operator Monday to Friday 7am to 3pm After hours assistance as required
Alternative 2: 24x7 Outsourcing	Outsourced	Dedicated operator 24x7
Alternative 3: Hybrid	Hybrid	In-house business hours Outsourcing after hours
Alternative 4: 8x5 In-house with Relief Operator	In-house	One operator during business hours Relief Operator On-call with remote SCADA for some afterhours outages On-call field crew as first responder

Option A: 24x7 In-house Control Room

As mentioned in section 3.1.1, for the purposes of cost/benefit analysis, this report assumes six operators and one supervisor will be used to staff at 24x7 control room. Although it is theoretically possible to use less staff, this is sub-optimal as it causes scheduling problems related to vacations, training, and sick time, reduces the ability of the control room to deal with higher workloads during business hours and outage events, and introduces high levels of overtime.

There many approaches for scheduling the six operators, however they all center around the following concepts:

1. Ensuring there is always at least one operator on desk
2. Ensuring there are two operators on desk during busy times – typically during business hours
3. Having spare operators to cover vacations, training, etc.
4. Ensuring that each operator averages out to around 40 hours per week over the course of the year

A common schedule uses twelve-hour shifts as follows:

5. Four operators are on twelve-hour shifts (day, night) working alternating three-day and four-day weeks to provide 24x7 coverage
6. Two remaining operators are used to provide additional resources to deal with construction and outages during business hours and to cover vacations and training
7. The two extra operators may also be used during weekday evenings if warranted and not precluded by vacation or training coverage

Twelve-hour shifts have the disadvantage that because outages can occur at any time, and each operator can only work sixteen hours in a row, if an outage occurs towards the end of an operator’s shift, and they need to stay to assist with the restoration, they may hit the sixteen-hour limit and another operator will need to come in to replace them. Some utilities use eight-hour shifts to reduce this problem as shown in Figure 2.

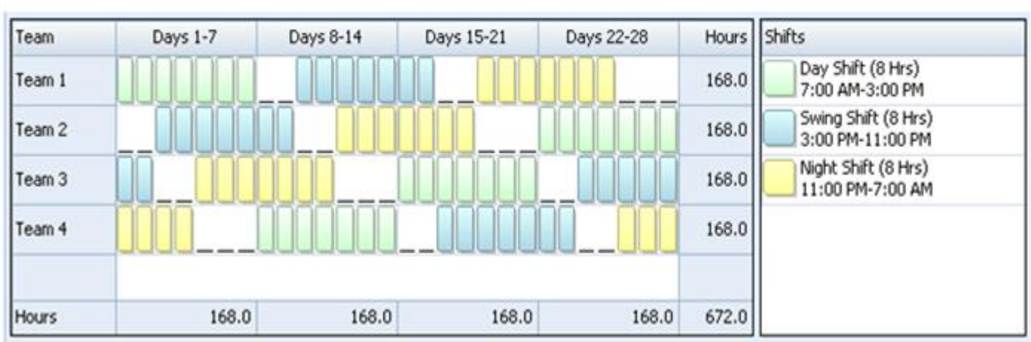


Figure 2: 24x7 Coverage Using Four Teams (People) and Eight-hour Shifts

The basic eight-hour shift schedule uses four operators (referred to as “teams” in the diagram), rotating through the three eight-hour shifts over the course of 28 days. Two additional operators can be used to add a second operator during weekdays (day shift) and weekday evenings (swing shift) and/or cover vacations and training when required.

The basic eight-hour shift schedule can be improved by considering the extra two operators as follows:

1. Each of the extra operators is scheduled for five eight-hour shift per week on weekdays, one during the day shift and one during the evening shift, and they swap shifts each week
2. If the original four operators each drop an evening shift when there is an extra operator on shift, then each operator work twenty days
3. This ensures that there are two operators on day shift five days each week, two operators on evening shift four days a week, and one operator on at all other times.
4. To improve fairness, every twenty-eight days, the two extra operators can be added to the rotating shifts and two rotating shift operators become the extra operators.
5. The extra evening operator will be the one that can be on training or vacation, although that will require someone to cover the one evening shift when they would have been the only operator on shift.

Some overtime may be required to cover storms, however due to the initial level of coverage, this should be minimal. Some training may be done during evening shift when two operators are on shift, but the system is quiet. The supervisor can also cover the occasional shift, to help with vacations and training.

Option B: Two In-House Operators Working Twelve Hour Shifts Monday to Saturday

The second in-house option studied in this report uses two fulltime operators as follows:

1. Onsite coverage (i.e., in the control room) is Monday to Saturday, twelve hours per day
2. The two operators alternate, working three days per week each for a thirty-six-hour work week; time spent responding to after hour events increases their hours to the forty-hour range
3. Each operator is provided with a home SCADA, cell phone and radio to respond to events (e.g., storms and other outages) outside of their onsite working hours
4. The initial cost of the home SCADA is $6000 per operator; this is in addition to the initial costs identified in section 3.1.5

The above schedule can be adjusted in various ways to accommodate various scenarios – e.g.:

- Using storm forecasts to predict the need for after-hours restoration, the operators could reduce their daytime onsite hours and return to deal with the storm later in the day.
- On-call field crews can share responsibility for responding to after hour trouble calls to reduce operator overtime.
- During weeks of extensive construction and field crew coordination, both operators could work from the control room during business hours (8x5) and use overtime to deal with storms and other after-hour events.
- During extended after-hours events, one operator could begin handling the event using their home SCADA, while the other operator goes to the control room; the operators could alternate at home vs. onsite duties.

This alternative has an obvious limitation around training and vacation time coverage which will require overtime or additional personnel.

Alternative 1: Outsource During Business Hours; After Hours Assistance as Required

This alternative is based on MHD's current outsourced operations contract, improved through the use of a service level agreement (SLA) as follows:

- Dedicated operator coverage from 7:30am to 3:30pm to coincide with MHD field crew working hours.
- After-hours response to SLA defined tasks (e.g., emergency calls and outage events) within defined timeframes.
- Dedicated operator for MHD system during storms that are likely to cause outages

Table 6 shows the initial costs of setting up this alternative, based on the following assumptions:

- MHD will provide the consoles and workstations to the outsourcer. Moving the consoles will be done by MHD personnel at no extra cost.
- MHD will need to set up communications for the SCADA workstations, phones, and radios
- The redundancy and resiliency improvements are still required

Table 6: Alternative 1 Initial Costs

Expense	Cost
Consoles	$70,000
Communications	$2,500
Redundancy & Resiliency	$45,000
Total Initial Costs	**$117,500**

Table 7 shows the ongoing annual costs of this alternative based on the following assumptions:

- The outsourcer will need between 1.5 and 2 fully loaded operators to cover operations during the day.
- Based on AESI's research using publicly available data2, forty storms per year is a reasonable estimate of the required storm coverage. At four hours per storm, this equals four weeks of overtime per year or approximately 0.1 operators
- Twenty percent is a reasonable markup on the cost to the outsourcer
- The redundancy and resiliency improvements are still required

Table 7: Alternative 1 Annual Costs

Expense	Annual Cost
1.6 to 2.1 Outsourced Operators * 1.2	$408,000 to $536,000
Redundancy & Resiliency	$49,100
Total Annual Costs	**$457,100 to $585,100**

[2] https://www.currentresults.com/Weather-Extremes/Canada/stormiest-cities.php

Alternative 2: 24x7 Outsourcing

This alternative is based on the outsourcer providing at least one operator to cover MHD operations at all times. The approximate cost of 24x7 outsourcing can be determined as follows:

- 24x7 coverage requires 168 operator hours per week
- Assuming each operator work a forty-hour work week, this translates to approximately four operators
- An additional one or two operators would be required to cover vacations and training
- Approximately half of the outsourcer's supervisor time would be allocated to the operators dedicated to MHD
- The markup on a 24x7 operation may be lower (e.g., fifteen percent) since all of the income is guaranteed, unlike the afterhours work in the Alternative 1
- The redundancy and resiliency improvements are still required

Table 8 shows the annual costs for this alternative based on the assumptions above.

Table 8: Alternative 2 Annual Costs

Expense	Annual Cost
(5 to 6 Outsourced Operators + 0.5 Supervisors) * 1.15	$1,340,000 to $1,584,000
Redundancy & Resiliency	$49,100
Total Annual Costs	**$1,389,100 to $1,633,100**

Note that if the outsourcer has a large enough pool of operators for its own operations (e.g., six operators and supervisor), there may be some minimal economies of scale, largely related to optimizing the vacation and training schedule. This would lead to an outsourcing cost at the lower end of the scale in Table 8 – i.e., five operators and half a supervisor. Greater economies of scale are unlikely where operators are working on two separate SCADA systems (one for MHD, one for the outsourcer) since that still requires two separate crews to be on desk at all times.

The initial costs are the same as those for Alternative 1, i.e., $117,500. See Table 6 for details.

Alternative 3: In-house and Outsourcing Hybrid

This alternative is based on MHD building their own control room and using their own operator during business hours (8x5) and for storm response (on overtime). Training would also be done during off hours on overtime. The outsourcer would provide both 8x5 and afterhours storm/outage coverage when the MHD operator is on vacation.

AESI estimated the cost of the outsourced operator services as follows:

1. Business hours and storm coverage during at least three weeks when the MHD operator is on vacation, plus some coverage for training that must be taken during business hours would require approximately 0.2 operators. Afterhours coverage will likely be one full operator as the outsourcer will want to cover the costs of training and interruptions to their own work. This provides a low end-estimate of 1.2 operators.

2. An alternative approach is to assume the outsourcer will devote 0.3 to 0.5 of an operator for each of the 128[3] hours that the outsourcer would be supporting MHD after hours or during storms. This results in approximately 1.2 to 1.8 of an operator to cover the afterhours support[4].

In either case, due to the uncertainty of the work, a reasonable markup would be twenty percent. Table 13 summarizes the annual costs of this alternative.

Table 9: Alternative 3 Annual Costs

Expense	Annual Cost
1 In-house Operator	$212,600
(1.2 to 1.8 Outsourced Operators) * 1.2	$306,000 to $459,000
Other Operating Costs	$53,300
Total Annual Costs	**$571,900 to $724,900**

Initial costs (summarized in Table 10) will include the cost to build the in-house control room, an additional console and SCADA workstation for the outsourcer, and the setup of communications to the outsourcer's site.

Table 10: Alternative 3 Initial Costs

Expense	Cost
In-house Control Room	$512,000
Third Console	$35,000
Third SCADA Workstation	$6,000
Communications	$2,500
Total Initial Costs	**$555,500**

Alternative 4: In-house Control Room with One Operator and Relief Operator

This alternative is based on the following scenario assumptions:

- MHD will build the in-house control room and staff it with one operator during business hours (8x5)
- The MHD operator and the relief operator will have home SCADA for responding to call after hours (on overtime)
- Training will mostly be done afterhours on overtime, but some training may need to be during business hours
- An MHD relief operator will be used to cover business hours and/or storms while the operator is on vacation
- On-call will be divided between the MHD operator, the on-call field crew, and the relief operator
- The cost of the relief operator is estimated to be the cost of 0.3 of an operator

[3] 24x7 coverage requires 168 hours; since MHD is covering 40 of those with their 5x8 operator, the outsourcer covers the other 128.
[4] 128 hours is equivalent to 3.2 operators; but since the operator is only dedicating 30% to 50% of their time to MHD tasks, the cost to MHD should be for 1.2 to 1.8 operators

The initial costs will be the cost of the control room and the cost of two home SCADA installation for a total of $524,000. Table 11 summarizes the annual costs based on the above assumptions.

Table 11: Alternative 4 Annual Costs

Expense	Annual Cost
1 In-house Operator	$212,550
1 Relief Operator (0.3 Operator)	$63,765
Other Operating Costs	$53,300
Total Annual Costs	**$329,615**

3.2. Potential Benefits Analysis

This section analyzes both quantitative and qualitative benefits of the six options described in section 3.1.6. Table 12 summarizes the costs and the SAIDI/CAIDI improvements for each of the scenarios.

Table 12: Cost and SAIDI/CAIDI Improvement Summary

Option Name	Option Description	Internal Annual Cost (rounded)	External Annual Cost (rounded)	One Time Costs	Improvement in SAIDI/CAIDI
Option A	24x7 In-house	$1,532,975	$0	$512,000	Maximum
Option B	12x7 In-house	$478,400	$0	$524,000	Maximum while on desk at work; A few minutes of response time added for at home response
Alternative 1	8x5 Outsourcing	$0	$457,100 to $585,100	$117,500	Close to maximum during business hours; varies in response time after business hours
Alternative 2	24x7 Outsourcing	$0	$1,389,100 to $1,633,100	$117,500	Close to Maximum assuming operators dedicated to MHD or rotated through more often
Alternative 3	Hybrid In-house + Outsourcing	$265,900	$306,000 to $459,000	$555,000	Maximum during business hours; varies in response time after business hours
Alternative 4	8x5 In-house with Relief Operator	$329,680	$0	$524,000	Maximum while on desk at work; A few minutes of response time added for at home response. Extra time added for field crew on call with relief operator called in

3.2.1. Outage Reduction

At this time, MHD only charges C/I customers under 50 kW for kWh. No residential customers are charged for energy used and no greater than 50 kW C/I customers are charged for energy used.

For “GENERAL SERVICE LESS THAN 50 KW” there is the “Distribution Volumetric Rate” which is 0.0184 $/kWh and there is the “Low Voltage Service Rate” which is 0.0006 $/kWh.

For the 2020 data, the General Service Less than 50 KW averaged 9.126518265 MWH per hour. If the SAIDI/CAIDI was improved by an hour per year for every Less than 50 KW customer, the savings would have amounted to $173.40. This was calculated for 2011 through 2020 and the average saving was $185.08 for each year. Given the average SAIFI/SAIDI rates from 2011 to 2021, saving an hour per customer would be highly unlikely. Even with a 25% improvement of SAIDI/SAIFI, the amount would be much lower than $185. This is insignificant relative to the costs of implementing an in-house control room.

A control room may also reduce the amount of field crew work and truck costs by providing more efficient instructions from a knowledgeable operator. For example, if the field crews averaged 600 hours of work time after hours in a year, saving 5% of that time would save 30 hours of costs for crew and truck.

Using the hourly rates from in the latest Collective Agreement that is available online, the rate for a crew after hours on double time with a lead hand and journeyman line is $186.22 per hour. The cost of running a line crew truck is approximately $100. Saving 30 hours of field crew and truck time in a year translates to savings of approximately $8600. As was the case with the SAIDI/SAFI improvement, this annual cost reduction is insignificant relative to the cost of implementing an in-house control room.

3.2.2. Response Efficiency

The effect of various scenarios reviewed in this report depends on how much of the time a knowledgeable operator is available.

The General Effect of Operators on Improvement in SAIDI/CAIDI

An in-house operator who is “on-desk” and therefore always monitoring the system, will be able to provide a faster response to an event than an outsourced operator who is normally monitoring their own system and must also listen for an alarm from the MHD system, switch tasks, possibly move to another desk, adjust to a different interface, etc.

Some events (e.g., fuse blows, underground feeder fails) may not produce any alarms in SCADA and would only be observable if the operator were monitoring the OMS at all times, which again would not be the case for an off-desk operator.

This section attempts to provide a reasonable quantification of these differences based on AESI’s control room experience.

In order to take effective action, an operator needs to have the following:

1. An understanding of the SCADA tools including the OMS interface
2. A good understanding of the location of the fault
3. An understanding of the layout of the feeder(s) affected and the adjacent connected feeders
4. A knowledge of the switches that have remote control that will enable them to isolate the fault and restore power to adjacent feeder sections.
5. A knowledge of the manual switches that can be operated by field crews that can be used to isolate the fault or switch feeder sections.

6. A knowledge of the geographic layout of the feeders and roads in order to be able to direct the crew to the correct general location to investigate the fault.
7. An understanding of the loading of adjacent feeders so they can decide to add part of one feeder to another feeder quickly, knowing where to check the applicable loading.

An operator that is regularly on the MHD SCADA desk will have the above characteristics and be able to respond quickly. Operators who rotate to the MHD desk less frequently will take time to readjust to the MHD interface. The less often that an operator is on the MHD desk, the longer they will take to respond.

When a fault occurs on a feeder that has several segments that can be subdivided by automatic or manual switches, then once the operator knows which segment has the fault, they can act to isolate the segment and then restore power to other sections. Once the exact location of a fault is determined, it should be possible to perform this action within five minutes by using four switching actions: open switches on either side of the faulted segment, close the feeder breaker, close the normally open switch to energize the segment below the feeder. This can greatly reduce the outage time for most customers on the feeder. The operator can then work with the field crew to open and close manual switches as needed and then direct them to the approximate location and ensure they are safe to correct the outage cause.

An operator that comes from another SCADA and utility desk needs to review the system and trace things out. They will not be able to respond as quickly and will take longer to be certain of the actions to take. They will need to review the outage message, locate the feeder in question, review the fault indication data and then trace the feeder to identify the location of the fault on the feeder. In order to dispatch the field crew, they will have to identify the street and street location the feeder is on. They can then dispatch the field crew and try to provide them the correct location. Then they will take time to identify where controllable switches are on the feeder in relation to the fault. They will take 20 to 30 minutes before being certain enough to take the same interim switching actions.

Note: These timings are estimates based on experience to try and quantify operator response. An operator that is very familiar with the system might actually perform the switching within one minute of getting the alarm and then dispatch the field crew. These numbers are an estimate to illustrate the difference between operator scenarios.

This discussion can be summarized as follows:

1. An MHD operator on the desk at work will have the fastest response time and provide the most knowledgeable direction to field crews
2. An outsourced operator on the MHD desk at least every other week (e.g., they are regularly cycled through their own host system and the MHD system) will be the next most efficient. If the outsourced operators are dedicated to the MHD desk, then they should be equal to the response times of 1.
3. An on call MHD and relief operator responding to an issue at the home SCADA while awake will be close to being as efficient as at work but won’t have the paper maps up on the wall to look at and will likely be the 3rd most efficient.
4. An on call MHD and relief operator responding to an issue at the home SCADA after being woken up from sleep may have some slowdown to their response. Depending on how quickly they wake up, they may be almost as efficient as in number 3 but may also be as slow as number 5 but should be faster than number 6.

5. An outsourced operator who only cycles through the MHD desk every few weeks will be the 4th most efficient but will likely get faster through the week if there is activity on the system.
6. An outsourced operator who is on shift at another desk and never assigned regularly to the MHD desk and then comes over to respond to an MHD issue will be the 5th most efficient.
7. An on-call field crew receiving a trouble call will take time to decide whether an operator is needed on SCADA. Once called, with at home SCADA, the MHD and relief operator will be as efficient as 3 if awake and 4 if not but the delay between the trouble call received and the MHD operator responding will be added to response time. The efficiency will be similar to 6 in response time but equivalent to 1 with respect to restoration time.

The operations can be ranked as follows for outage and emergency response:

1. Option A (24x7 In-house)
2. Alternative 2 (24x7 Outsourcing)
3. Option B (12x7 In-house)
4. Alternative 1 (8x5 Outsourcing)
5. Alternative 3 (Hybrid: 8x5 In-house; outsource afterhours)
6. Alternative 4 (In-house 8x5 with relief operator or field-crew)

Item 6 (Alternative 4) is difficult to quantify. During times when an operator is available on call, 6 would likely be faster than 5. If there are extended times without an operator on call during evenings or nights, then 5 will be better for emergency response.

OMS Response

The other main aspect of the effect of operator response on the length of outages is the reaction time to OMS alarms. The OMS will alarm any time there is a trouble call entered. This alarm reads “Received new calls from CSR”, CSR means Customer Service Representative. This then requires using the OMS interface to review the information recorded from the call. The call may be the first indication that a fuse has blown and there is a larger outage. An operator that is on the desk and monitoring the system will start paying attention and then be able to determine there may be an outage and dispatch the field crew(s). If it is a fuse blown then the meter affected will issue an outage message that can be picked up by other meters nearby and reported to the AMI which transmits it to the OMS. The OMS may then infer an outage at the blown fuse. If this happens, then the operator can quickly dispatch the crew to the correct location. If the trouble call is not accompanied by more than 1 meter responding, then it may be a fault affecting only one customer. However, an operator monitoring the OMS will react more quickly than one not monitoring the OMS. The crew will still be required to travel to the site and correct the fault.

An operator that is on another desk may hear the alarm but may be busy with their own utility tasks and might be delayed several minutes. If they have a large issue of their own, their response may be delayed even further. If there is no one at home, or they are asleep, the trouble call may be delayed by hours. In such a case the fault may affect the meter and the meter will issue a last gasp and the fault will still be identified and can be corrected. However, that requires the operator to be monitoring the OMS since there will be no alarm of a trouble call, just an indication in the OMS that a meter is out. The difference may be a response within one minute versus a response within 5 minutes.

For an outsourced situation, the System Level Agreement (SLA) would have to ensure that an operator off the desk responds to alarms from the MHD desk within certain time frames. However, if the OMS is showing activities that don't alarm, there will need to be a requirement to periodically go to the MHD desk and check the OMS user interface.

3.2.3. Reliability Impact

In order to quantify the potential changes to the length of an outage and thus changes to SAIDI/SAIFI, AESI has selected a scenario for analysis that takes into account the characteristics of the MHD distribution system. Most feeders have many switchable segments and normally open connections to other feeders. Some of the switches are remotely controllable while some require manual local control. A paper written in 1989 that was used as the basis of one of the first distribution automation systems in the world at Hydro Mississauga recommended 3.5 controllable switches per feeder – i.e., 3 controllable switches in the feeder with a controllable normally open point shared with another feeder. That scenario is taken as the basis for calculating the differences in operator response time and thus the potential CAIDI for the outage.

The following scenario is representative of the MHD system. A typical feeder may have 4 segments with the first segment following the transformer station breaker, followed by switchable devices separating the second, third and fourth segment. The fourth segment is separated from another feeder by a normally open switch. Most faults that cause outages will happen within a segment. This means that the breaker will trip and cause outage to the customers of each of the 4 segments. Some feeders will have fewer segments, some more while some of the switches are remotely controllable and some aren't.

For some feeders it will be possible for an operator to isolate the outage to one segment and restore the other segments. In some cases, the operator may be able to isolate the fault to two segments until a field crew arrives to open and close manual switches. In some cases, there are fault detectors on the switches that indicate the direction of the fault and expedite the fault location. In other cases, it will require the field crew to identify the location of the fault.

As discussed in previous sections there will be speed differences between an operator on the desk who is regularly experienced with the MHD system, an outsourced operator on the desk who only sees the MHD system every 6 weeks, and an operator not on the desk who is providing ad hoc support from another utility's desk.

Scenario for Experienced operator on desk:

Based on discussions with MHD and experience with distribution utilities, we will describe the following scenario:

1. A fault occurs on the third segment of a feeder and trips the breaker. An operator on the desk will be able to restore the first 2 segments of the feeder within 5 minutes if there are enough remotely controllable switches and if the fault location is known to the correct segment when the operator reviews the OMS information. This should happen within the first minute of the fault occurring and the breaker trip alarm. To be conservative, we are going to assume that there aren't enough remotely controlled switches on all feeders since this is the case with MHD who have plans to continue to install controllable switches that the first two segments can be restored in 5 minutes. The other unfaulted 4th segment will have to wait for a Field Crew to arrive to confirm the fault location is on the 3rd segment. Once the operators confirm the fault location, the operators can be directed to go to the manual switch and open it to isolate the fourth segment from the third faulted segment. The operator can then restore power to the unfaulted switch by closing the normally open switch.
2. For this scenario, we will assume that this is a cold call with the field crew at the MHD office. We assume that the operator has called out the field crew as soon as they know the faulted segment location. Within two minutes of the fault, the operator will tell the crew the fault is in the third or fourth segment (since the manual switch doesn't have a fault indicator to monitor). The operator will restore the first and second segments within 5 minutes of the outage alarm. The crew will take 13 minutes to arrive and another 5 minutes to confirm the fault is on the third segment. The fault location is confirmed within 20 minutes of the outage alarm. The operator will direct the field crew to go and open the switch from the third to the fourth segment. It will take 3 minutes to get there and 10 minutes to prepare and operate the switch. It will take another 2 minutes for the operator to close the normally open switch to restore power to the fourth segment.
3. Assuming 25 customers on each segment, this means that 50 customers have their power restored in 5 minutes after the fault. Another 25 customers get restored 35 minutes after the fault.
4. The field crew then takes 45 minutes to repair the feeder and correct the fault. The operator can then operate the 3rd segment switch and restore power to the third segment. The third segment has then experienced an 80-minute outage.
5. If the connected feeder is from the same bus, then rules may allow the field crew to close the switch between the 3rd and 4th segment and then go and open the normally open switch. If the feeder is from another bus, or even another transformer station this may not be allowed. It is assumed that first the field crew closes the open switch to the 4th segment to loop two feeders and then opens the normally open switch.
6. The sum of outage times is equal to 50 * 5 + 25 * 35 + 25 * 80. This provides a per customer average of 31.25 minutes.

Scenario for Once every 6 weeks operator on desk:

1. This is the same scenario as above. However, as discussed in the previous section, the operator is not as familiar with the MHD system and takes longer to determine what to do. As a result, the 50 customers are restored after 20 minutes while the other parts of the repair and restoration are the same.
2. The sum of outage times is equal to 50 * 20 + 25 * 35 + 25 * 80. This provides a per customer average of 38.75 minutes.

Scenario for Operator from another desk but being one rotated through every 6 weeks:

1. It is assumed that this operator has some familiarity with the MHD system but will take longer to respond and longer to call out the field crew and give them correct directions. This operator will take 30 minutes to restore the 50 customers. It will also take 25 minutes for the field crew to get to confirm the fault is in the third segment since it takes the operator longer to figure out where to send them. This adds 5 minutes to fault for the 4th segment before they are restored. It also adds 5 minutes to the time of full restoration.
2. The sum of outage times is equal to 50 * 30 + 25 * 40 + 25 * 85. This provides a per customer average of 46.25 minutes.

Scenario for Operator from another desk with only periodic time on MHD desk in response to issues:

1. It is assumed that this operator only has some periodic exposure to the MHD system and desk. They will get some training in the system, but the response will be much slower than someone with regular exposure. It is assumed that the operator will take extra time to figure out the situation but will call out the field crew once they understand. It is assumed that the operator will only operate the remote switches and then get the crew to repair the fault. They will restore the two segments in 35 minutes. The field crew will take 30 minutes to arrive to the correct location of the fault. Then they will take 45 minutes to repair. The operator will operate the switch to restore segments 3 and 4 once satisfied that the crew is safe. This will take another five minutes. This will mean the outage is completed after 80 minutes.
2. The sum of outage times is equal to 50 * 35 + 50 * 80. This provides a per customer average of 57.5 minutes.

Operators Not Comfortable with interim restoration:

1. There may be times when operators coming from another desk after hours do not provide switching help other than closing the breaker when all is clear. They may not feel comfortable with partial restorations that involve manual switching since this can lengthen the outage for some. This means that all 100 customers experience the full length of the outage. The time for the field crew to arrive and find the fault location will be 30 minutes. The time to repair will be 45 minutes. Then it will take 2 minutes for the operator to get the breaker closed.
2. This results in an average outage time of 77 minutes.

Scenario for MHD At home operator with SCADA

1. This is similar to Scenario 1, but it is estimated that an awake operator will be delayed 2 minutes in responding and an asleep operator will be delayed 5 minutes in responding. This will be estimated to be 3.5 for all at home responses.
2. The sum of outage times is then 50 * 8.5 + 25 * 38.5 + 25 * 83.5. This provides a per customer average of 34.75 minutes.

Scenario for on call Field Crew

1. In this case there is no on call operator. The field crew has to identify that there is a breaker lockout outage. This will take 2 minutes. They will call in Engineering staff to sit at the operator desk. Meanwhile, the field crew will go and patrol the feeder to try to confirm where the fault is. They may take an extra ten minutes to identify where the fault is (30 minutes from time of fault) and what the repair is required. They take 50 minutes to repair the fault plus 5 minutes to re-energized the isolated segments. They take 50 minutes because they have to coordinate with the Engineering staff regarding the opening of the second switch while closing in the breaker. The Engineering staff person will have to drive to the office, log in to the SCADA, review the alarm, check the SCADA and then confirm which switch to operator prior to closing the breaker. The drive time will be assumed to be 25 minutes plus 15 minutes prior to opening the second switch and closing in the breaker.
2. The time for the Engineering staff to restore the first two segments is 42 minutes for a total of 42 * 50. The field crew takes 82 minutes to repair and then 5 minutes for the Engineering staff to restore the third and fourth segments for a total of 87 * 50. This provides a customer average of 64.5 minutes.

Summary of Improvements over no operator help with restoration:

The 7 scenarios have the following improvement factors against no operator assistance in reducing the lengths of faults through switching:

Table 13: Duration Improvement for each Option

Scenario	CAIDI for this fault
1	31.25
2	38.75
3	46.25
4	57.5
5	77
6	34.75
7	64.5

The operations can be ranked as follows for outage and emergency response:

1. Option A (24x7 In-house)
2. Alternative 2 (24x7 Outsourcing)
3. Option B (12x7 In-house)
4. Alternative 1 (8x5 Outsourcing)
5. Alternative 3 (Hybrid: 8x5 In-house; outsource afterhours)
6. Alternative 4 (In-house 8x5 with relief operator or field-crew)

Alternative 1 will be considered the baseline as it is similar to the current outsourcing contract. Alternative 1 is a combination or 40 hours of Scenario 2 with 128 hours of Scenario 3. This assumes that the contract will ensure that the off hours operators will be willing to perform switching to reduce the lengths of faults. This results in standard feeder faults average of 44.46 minutes.

Option A and Alternative 2 will have 168 hours of scenario 1 i.e., outage times of 31.25. This is a 29.7% improvement over Alternative 1.

Option B will have 72 hours of Scenario 1 and 94 hours of Scenario 6. This provides average outage times of 32.61. This is a 26.65% improvement over Alternative 1.

Alternative 3 will have 40 hours of Scenario 1 and 128 hours of Scenario 4. This provides an average outage time of 51.25. This could be improved if the MHD operator were called in for storms and handled the outages during storms. This would then be closer to Scenario 1 taking into account outages that are not storm related. This is 15.26% worse than Alternative 1 but would be mitigated by calling the MHD operator in for storms. Alternatively, the operator could also have at home SCADA to respond to outages after hours. This would reduce the amount of time for involvement of outsource operators in restoring outages.

Alternative 4 will have 40 hours of on desk operator with 160 hours of storm call in an average of 3 hours storm call in time per week for 43 hours of on desk time for scenario 1. An operator will be considered on call from 4 to 11 on weekdays and 8 to 4 on Saturday for a total of 43 hours of Scenario 6. The other 82 hours will be on call field crews with scenario 7. This will result in an average fault time of 48.38. This is 8.46% worse than Alternative 1.

Table 14 contains the summary of average outage times and improvements.

Table 14: Duration Improvement for each Option

Option	Scenarios	Average Scenario Outage Time	Improvement over Option c
Option A	168 hours of scenario 1	31.25	29.7%
Option B	72 hours of Scenario 1 and 94 hours of Scenario 6	32.61	26.65%
Alternative 1	40 hours of Scenario 2 with 128 hours of Scenario 3	44.6	0%
Alternative 2	168 hours of scenario 1	31.25	29.7%
Alternative 3 (worst case)	40 hours of Scenario 1 and 128 hours of Scenario 4	51.25	-15.26%

Alternative 4	43 hours of scenario 1, 43 hours of Scenario 6 and 82 hours of scenario 7	48.38	-8.46%

These numbers are an illustration of what is possible given a specific scenario. Different outage scenarios will provide greatly varying scenarios for improvement.

3.2.4. Customer Loss Reduction

AESI used the ICE spreadsheet to calculate the benefit of improved reliability that would occur with MHD having its own control room.

"The Interruption Cost Estimate (ICE) Calculator is a tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements." This is found at "icecalculator.com/home". This tool is publicly available. "The ICE Calculator is funded by the Energy Resilience Division of the U.S. Department of Energy's Office of Electricity (OE) under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231."

AESI has assembled data from MHD publicly available information including the following:

1. Number of residential customers
2. The total MWH per year per residential customer
3. Number of C/I customers under 50 kW service
4. The total MWH for C/I customers under 50 kw service
5. Number of C/I customers over 50 kW service
6. The total MWH for C/I customers over 50 kw service
7. The SAIDI, SAIFI and CAIDI numbers from 2011 through 2021. Used the numbers that excluded loss of supply.
8. MHD provided information showing the manufacturer percentage at 31.8%. AESI decided to round off the manufacturer percent to 32 while reducing the percentage of service companies.
9. The data includes number of people per household broken down into age groups in order to calculate the Residential benefits.
10. The median annual income for Milton households
11. The percentage of manufacturing companies by total MWH per year.
12. The GDP for Milton for 2016
13. The total MWH for all the Commercial and Industrial Users

With these numbers it is possible to estimate the costs of improved reliability.

The ICE tool is available with an option to calculate cost savings based on improved SAIDI/SAIFI/CAIDI numbers. AESI used this tool while considering SAIDI improvements of 10%, 15%, 20% and 25%.

The ICE tool does not include default data for Canadian provinces or cities, so AESI utilized the publicly available Milton specific data to create a Milton specific model. AESI used MHD data from 2020 to define the total customers for each category and the total load for each category.

AESI used the MHD SAIFI/SAIDI numbers from the documents provided to the OEB for 2011 through 2020. In addition, MHD provided their 2021 numbers to AESI for study.

There are two tables that provide the input. The following is the Reliability Without Improvement table. These values are the MHD reliability numbers excluding loss of supply faults but including major events since these are the outages that can be improved for the customers. These are MHD's historical numbers. The ICE tool calculates the cost of outages to the customers based on these numbers.

Table 15: Reliability without Improvement

Year	SAIFI	CAIDI	SAIDI
2011	1.120	56.3	63.0
2012	1.050	46.3	48.6
2013	0.990	481.2	476.4
2014	1.060	69.1	73.2
2015	0.230	80.9	18.6
2016	0.590	75.3	44.4
2017	0.490	74.7	36.6
2018	1.180	125.6	148.2
2019	0.580	34.1	19.8
2020	1.150	79.3	91.2
2021	0.564	79.0	44.6

The next table is the reliability with improvement table. The table shown is for a 25% improvement of CAIDI and SAIDI for the same years.

Table 16: Reliability with Improvement

Year	SAIFI	CAIDI	SAIDI
2011	1.120	42.2	47.3
2012	1.050	34.7	36.5
2013	0.990	360.9	357.3
2014	1.060	51.8	54.9
2015	0.230	60.7	14.0
2016	0.590	56.4	33.3
2017	0.490	56.0	27.5
2018	1.180	94.2	111.2
2019	0.580	25.6	14.9
2020	1.150	59.5	68.4
2021	0.564	59.3	33.4

The following is the output results for the 25% improvement scenario. The results are in US dollars.

Table 17: Costs without and without improvement and total benefit

Year	Forecast of Total Sustained Interruption Costs		Total Benefit
	Without Improvement (Baseline)	With Improvement	
2011	$4,886,582	$4,478,099	$408,484
2012	$4,393,517	$4,084,390	$309,127
2013	$26,585,307	$18,591,237	$7,994,069
2014	$5,303,904	$4,775,068	$528,836
2015	$1,258,983	$1,115,805	$143,178
2016	$3,186,940	$2,845,428	$341,512
2017	$2,690,766	$2,404,213	$286,553
2018	$8,816,529	$7,404,452	$1,412,077
2019	$2,582,092	$2,444,316	$137,776
2020	$6,886,522	$6,115,833	$770,689
2021	$3,439,638	$3,055,746	$383,892

The following table is the summary of the results for the 10%, 15%, 20% and 25% scenarios. The results are all in US dollars for each year and the average is presented in US dollars. The results are converted to Canadian dollars using the 2016 average exchange rate since that is the base year of the ICE tool.

Table 18: Benefit per year, Average Benefit for 11 years for 4 improvement scenarios

Year	V10c: 10%	V15c: 15%	V20c: 20%	V25c: 25%
2011	$166,250.95	$247,849.02	$328,435.14	$408,014.18
2012	$125,447.59	$187,197.72	$248,302.33	$308,764.19
2013	$3,272,440.20	$4,878,118.46	$6,452,538.46	$7,988,225.92
2014	$215,990.19	$321,631.03	$425,713.02	$528,244.46
2015	$58,653.76	$87,255.51	$115,377.23	$143,021.62
2016	$139,706.29	$207,927.50	$275,068.32	$341,134.68
2017	$117,206.92	$174,449.40	$230,790.85	$286,236.22
2018	$584,000.91	$866,104.07	$1,141,646.10	$1,410,659.87
2019	$55,700.89	$83,222.18	$110,525.02	$137,610.15
2020	$315,595.81	$469,551.18	$620,962.87	$769,845.07
2021	$157,192.83	$233,880.31	$309,304.10	$383,471.25
Average	$473,471.49	$705,198.76	$932,605.77	$1,155,020.69
CAD $	**$627,025.69**	**$933,905.74**	**$1,235,064.39**	**$1,529,611.95**

Costs Versus Benefits

Table 19 contain the costs from Table 12 and the SAIDI/CAIDI improvements for each of the scenarios. It shows the potential cost savings for each option based on the potential improvement in SAIDI/CAIDI but also recognizing that some types of faults may make it difficult to reduce. For the 24x7 Option 1 and Alternative 2 we will assume at least a 20% average improvement for most lengthy faults. For Option B, we will assume at least 15% improvement. Alternative 1 is analogous to MHD's current outsourcing contract and thus considered the baseline. The exact improvements will vary from operator to operator. However, the MHD CAIDI stats show that the average interruption for 9 of the 11 years is not much more than 1 hour and 20 minutes. The two years that are different had major storms. The key point is that a dedicated on-desk operator will much more rapidly restore an outage than an operator that comes over from another desk.

These percentages are chosen because there are many outages that can't be reduced by switching because they may involve a fuse that has blown or some other event that causes an outage that can't be partially restored for some customers. It may not be possible to reduce the outages significantly other than reacting more quickly to a trouble call as discussed above. Reacting more quickly to a trouble call may reduce the overall fault by a few minutes but this is not as significant a change as being able to quickly restore power to some customers. For a fuse blown, the overall fault will still require crew travel and repair of the fault by replacing the fuse. Reacting more quickly might shave a few minutes on a fault perhaps reducing it from 48 minutes to 45 minutes. However, these faults tend to affect fewer people. This means that the ability to reduce overall SAIDI and CAIDI is a combination of the larger percentage improvements achievable by quick switching on some faults and the much smaller percentage improvements from reacting more quickly to a trouble call.

This table summarizes the costs for MHD and the potential savings to customers for each scenario.

Table 19: Costs and Savings Comparisons

Option	Option Description	Annual Costs (rounded)	One Time Costs	Improvement in SAIDI/CAIDI over option c	Potential Annual Average Savings
Option A	24x7 In-house	$1,532,975	$512,000	29.70%	$1,235,064.39 (based on 20% average improvement)
Option B	12x7 In-house	$478,400	$524,000	26.65%	$933,905.74 (based on 15% average improvement)
Alternative 1	8x5 Outsourcing	$457,100 to $585,100	$117,500	0%	$0 (equivalent to existing outsourced contract)
Alternative 2	24x7 Outsourcing	$1,389,100 to $1,633,100	$117,500	29.70%	$1,235,064.39 (based on 20% average improvement)
Alternative 3	Hybrid In-house + Outsourcing	$621,000 to $774,000	$555,500	-15.26%	<$0

Alternative 4	8x5 In-house with Relief Operator	$329,615	$524,000	-8.46%	<$0

Analysis of Costs over 5 years

It is useful to compare the costs over 5 years of an expected 24x7 outsourced service versus the equivalent in house 24x7. The following table shows a comparison of Options A and D.

Table 20: Comparison of cumulative costs

Option	One Time Costs	Annual Costs	Year 1 total	Year 2 total	Year 3 total	Year 4 total	Year 5 total	Year 10 total
Option A	512,000	1,532,975	2,044,975	3,577,950	5,110,925	6,643,900	8,176,875	15,841,750
Option B	524,000	478,400	1,002,400	1,480,800	1,959,200	2,437,600	2,916,000	5,308,000
Alternative 1	117,500	585,100	702,600	1,287,700	1,872,800	2,457,900	3,043,000	5,968,500
Alternative 2	117,500	1,633,100	1,750,600	3,383,700	5,016,800	6,649,900	8,283,000	16,448,500
Alternative 3	555,500	774,000	1,329,500	2,103,500	2,877,500	3,651,500	4,425,500	8,295,500
Alternative 4	524,000	329,615	853,615	1,183,230	1,512,845	1,842,460	2,172,075	3,820,150

3.2.5. Benefit analysis for MHD, staff and customers

This section provides a list and description of the benefits to having and in-house control room dedicated on desk operators for MHD overall, as well as to its staff and customers. The benefits discussed below are as follows:

1. Flexibility to adapt to the rapid changes coming to the electric power system
2. Improved system reliability through outage length reduction
3. Improved situational awareness for the operator
4. Improved clarity of what is happening in the system for field crews
5. Provide clearer direction to field crews and reduce driving time
6. More consistent safety for field crews
7. Improved clarity of the OMS notes describing the stages of outages
8. With a local control room, upper management can get a quicker understanding of situations
9. Quicker response to emergency calls from police or fire departments during all hours
10. Orders to Operate are prepared by someone with clear knowledge of system state
11. Provides better use of the controllable switches that have been installed

Flexibility to adapt to the rapid changes coming to the electric power system

MHD is reviewing the costs of implementing an in-house control room versus outsourcing the control room responsibilities. The current contract does not clearly define the outsourcer duties for the off-desk hours. MHD has prepared a Service Level Agreement that will be used to clearly define the on-desk and off-desk responsibilities. The entities that bid on the outsourcing contract will also want to have their responsibilities clearly defined so that they can accurately estimate the work required. Unfortunately this typically means that once the 5-year contract is signed and approved, it may be very difficult to change the responsibilities for the outsourced operators. For example, if MHD added a DERMS application to their

SCADA, that would add another responsibility to the outsourcer operators that is not described in the contract. MHD could include such responsibilities now, but this would likely increase the costs of the initial contract with unnecessarily.

If MHD implements in-house control room, they have much more flexibility to decide when and how to add new applications and responsibilities. In-house operators would be hired with the understanding that new responsibilities will be added over time in anticipation of the upcoming changes to the electric grid resulting from climate commitments being made by governments - e.g., electrification of transport, rapid growth in the number DERs on the distribution system. The power system is going to change and MHD has to be ready to change with it.

A recently issued EDA position paper, titled “The Local Distribution Company Role in Enabling & Operating Distributed Energy Resources” and intended to influence the upcoming OEB DER Roadmap, summarizes the need for infrastructure investment and regulatory flexibility in related to decarbonization as follows:

- Significant investments in distribution-system infrastructure are necessary over the coming decade to achieve deep decarbonization of the economy.
- LDCs will require regulatory flexibility to make the necessary investments to achieve the government’s decarbonization objectives and to maintain the ongoing reliability of the system.

The significant investments that will be required as a minimum are electrification of transport and residential/business heating. The electrification of transport will require a minimum 30% increase in the energy needed to charge vehicles. This energy will be needed to charge vehicles more quickly than it is used. This could increase the demand load for charging from 60% to 120% of the distribution system capacity at times. It is also likely that new construction of residential buildings may also switch to electric heat as well, requiring additional capacity to the distribution grid. The average household electricity use in Ontario is 722 kWh per month. In Quebec, with almost all residences using electric heat, the average use per month is 1550 kWh per month. This would require another significant investment in the distribution grid. The amount of the investment could be reduced with careful monitoring of the distribution systems by experienced operators with the tools to monitor the system loading and potentially to move loads around to better balance the system.

If MHD outsources its control room functions, they will have difficulty making changes to operations to support and monitor the complex changes required. To make the changes to the contract with the service provider would require negotiation of the potential tasks that are new and may be hard to quantify. The result would be ongoing efforts to negotiate with the service provider that would likely result in increased costs each time changes were required. Since the complexities of some of the new tasks are hard to quantify, it is likely the service provider will want to increase price to protect themselves. MHD could save the time of negotiating with an external service provider if they build these into their own operations team training that learns as it goes. The alternative would be to negotiate the cost structure of continuously changing responsibilities into the contract up front for a 5 year outsourcing contract. The service provider may not use the same SCADA tools as MHD and this will increase the training costs for the service vendor if they don’t dedicate operators to the MHD system. The result could be a higher operations cost from the service provider.

If MHD has their own 24x7 control room and is able to implement new operational functionality and train their own operators to use it, then they will be able to stay on top of the rapid and complex changes that are coming.

MHD has within its service territory more than twenty large facilities with flat roofs that would be perfect candidates for solar arrays. There is space to add BESS (Battery Energy Storage Systems) systems to go with the solar arrays. MHD could end up with up to 30 MW of solar generation with the BESS capacity to go with it. These Distributed Energy Resources (DERs) can be generating at one point and then quickly switch to charging the BESS depending on the needs of the grid. This could include going from generating 30 MW with solar, to using the 30 MW to charge the BESS. This would involve a total of 30 MW swing spread out over a few MHD feeders. MHD would need operators with the right skills and the right tools to be able get the system configured to allow such a big power swing in the distribution system. In order to optimize the use of power and provide for the stability of the Grid, tools to monitor and facilitate DER and BESS flexibility are an important requirement.

To handle this DER and BESS variability would require MHD to be able to monitor the DERs and possibly control them using DERMS software and ensure that it was being used to not only support the grid but also to not harm the distribution system. The operators would also need SCADA to have powerflow tools with simulation capabilities that would enable them to test out different DERs output levels and how they affect flows and how changing from 30 MW output to locally charging the BESS would affect the distribution flows. MHD would need trained operators with the right tools to effectively manage such situations.

MHD will need tools to support these facilities as well as the growing number of charging facilities that will be needed to charge the large number of vehicles in Milton. With two (soon to be 3) interchanges on the 401, Milton may also become an important charging location for long haul truckers and have a significant load increase. This will require the flexibility to adapt and change their operations quickly. Having their own operators invested in the process to get to Net Zero will enable continuing successful change.

Improved system reliability through outage length reduction

As described in previous sections, an in-house control room can reduce the cost of outages for C/I customers. However, outages for manufacturers are also potentially times when things can break because of sudden stoppages or outages of computers. A shorter outage reduces this risk. For C/I customers with backup power, MHD having operators with the ability and knowledge of the system to more quickly reconfigure the system to restore some customers may mean that such C/I customers may not suffer any ill effects from an outage that is shorter that its backup power capability.

Residential customers are generally more satisfied with their service when the outages are shorter and fewer. Additionally, many Milton residents are working from home due to the pandemic and may continue to do so once the pandemic is over. Such customers may be adversely affected by longer outages, which an in-house control room helps mitigate.

Longer outages may also adversely impact retail customers, as society relies more on electronic payments. Consumers may be able to continue shopping during a short outage, but if the outage extends too long, they may not be able to pay, adversely impacting both the consumers and the retail customer.

Improved situational awareness for the operator

A dedicated on-desk operator gains experience with the SCADA tools that provide them a view of the system state in terms of device status, measurements and alarms. The operator can learn to quickly understand what is happening in the system. As they learn the system and the tools, they can get a good situational understanding and be able to make better and quicker assessments and decisions. When a storm or major event hits, they can use the system tools to monitor the situation. Different SCADA tools can be provided that show aspects of the system to the operator to assist their understanding. However, an operator with an understanding of the system layout and the normal range of flows can more quickly realize when something is not quite right and be able to respond. They also can get more value from the tools. As complexity is added to the system from DERs and charging stations, they can easily add this to their understanding of the system. An off-desk operator coming over to review a situation will take a lot of valuable time to understand what is happening before attaining a clear enough understanding to be able to act.

Improved communication of system state to field crews

The field crews have discussed their difficulty with the current situation because they don't have the view of the system that an operator with SCADA would. They can phone/radio and ask, but the current after-hours operator situation with someone coming over from another desk has not provided as much clarity and direction as quickly as they would like. The field crews want an accurate understanding of what is happening with the system and where the problems might be. An operator on the desk with a strong knowledge of the system and SCADA information to expand that understanding can provide a better understanding of the system and problems to the field crews much more quickly.

An operator on the desk with their good situational awareness can provide an accurate and relevant understanding quickly to the field crews. An operator coming from another desk will take some time assess the state of the system in order to be able to provide an accurate and relevant description of what is happening that is important to the field crews.

Clearer direction to field crews and reduced driving time

Receiving clearer direction regarding the actions they are supposed to take, helps field crews execute those actions quickly and with confidence. An experienced on-desk operator can provide a more accurate location of where an outage may be as well as brief the field crew on how they will work together to resolve the issue. An operator coming from another desk, in addition to taking longer to understand the situation, will also take longer to determine the best course of action and what the field crews then need to do, eroding confidence and slowing down the restoration process.

More consistent safety for field crews

Working on the distribution system can be dangerous and potentially fatal work. Line crews are trained to carefully test any lines they are working on and to ensure they take safety precautions for their own protection. Field crews follow the steps of Orders to Operate (OTO) prepared by control room operators and as directed by control room operators. Field Crews following proper procedure should never perform a step that is incorrect or that has not been tested for. However, during major outages and long stretches of overtime, it is possible that a field crew might make a mistake because of fatigue. In such a case it is possible that a dangerous incident might occur.

In such situations, making sure the control room operator has a clear understanding of the state of the system and can provide clearer direction, should prevent a potentially dangerous situation from occurring. An operator with a strong knowledge of the distribution system and understanding of what the SCADA/OMS tools are indicating will be able to provide a clearer understanding and clearer direction to ensure that an Order to Operate is safe and correct in its steps. Such an operator would be able recognize any anomalies that may show up in readings after each step is performed in an OTO and thus should minimize the potential for a dangerous situation to arise where a field crew mistake might be dangerous.

Improved use of OMS features such as notes, merging of trouble calls, etc.

An experienced on-desk operator can assist themselves (and other operators) by making better notes in the OMS interface and by properly merging trouble calls into outages so that the system identifies and organizes its information better. This can then provide more accurate information during a storm so that outages are more clearly identified. It can also provide better information to MHD customers in the online outage map. An operator coming from another desk may take longer to work with the OMS interface and may not be able provide added value to the use of the OMS to determine the exact nature of an outage. In addition, they may take longer to determine the best course of action.

Improved communications with upper management

A manager who needs some information may find it difficult to get it from an operator over the phone. With an operator in a local control room, the manager can visit and get good information that is illustrated using the screen or the paper maps in front of them. This can enable the manager to make better decisions. In some cases, better information can then be provided to the public in case of situations that affect them.

Quicker response to emergency calls from police/fire department

Having an operator on the desk will mean a quick response to an emergency call and a quicker response to handling the situation, especially if this means that power needs to be interrupted. An operator can then isolate the problem area and reroute power to customers to lessen the impact on the public. An operator off the desk will take longer to answer the call and will take longer to understand the location of the situation on the MHD system. They may also take longer to take action since they will need to be certain to perform the right action.

Orders to Operate are prepared by someone with clear knowledge of system state

The current situation is that some OTOs are prepared by field crew. The field crews believe it would be better for an on-desk operator with clear knowledge of the system and its monitored state to prepare the OTOs. An on-desk operator can more quickly understand the switching the needs to be performed. An operator coming from another desk will take longer to figure out the switching that needs to be performed. An on-desk operator with good system knowledge and understanding is also less likely to make a mistake in an OTO.

Better use of the controllable switches

An on-desk operator with a good knowledge of the system will be able to quickly ascertain what can be done with any given fault with their knowledge of the locations of controllable switches. This will mean that these resources can be better utilized to improve system reliability. An operator from another desk will not have as quick a knowledge of the controllable switches that can be used in any given situation.

3.3. Industry Direction and Future Benefits

3.3.1. Required Control Room and System Investments Based on Current and Planned Configuration of Renewable Energy Generation

1. MHD currently has and uses their SCADA Topology Processor as part of its OMS functionality. However, this function is not regularly used by all the operators. This tool could be used regularly by the operators to perform tracing on feeders they are not familiar with to show them the extents of the feeder. This function is also very useful with the Simulation function. With their own control room and an experienced control room supervisor, MHD could ensure that each operator is trained in and uses the tracing tool appropriately. This applies to each of the tools discussed below as well. An outsourced control room could do the same but may not have the same SCADA and associated tools as MHD. If they dedicate operators to the MHD desks, then their cost plus profit exceed the MHD cost of operations plus control room capital costs over 5 years.
2. The MHD SCADA system also has available a simulation tool that MHD has not implemented. The Simulation view allows operators to take a snapshot of the system and try out switching in a study version of the system. Things can be tried out safely in Simulation mode and then used as part of switching for a fault or for an Order To Operate (OTO).
3. The MHD SCADA vendor also has a Distribution Power Flow (DPF) program that can provide calculations of the flows and voltages on each part of a feeder in realtime mode or in simulation mode. DPF is also helpful in simulation mode for testing out the switching of feeder segments between sources to help balance feeders but also for switching segments over to another feeder temporarily for outage response. If the operator is concerned with loading, they can go into simulation mode and move a feeder segment over to another feeder and use DPF to analyze whether both feeders are still within limits.
4. Another tool that can be useful is to have a high-resolution large screen display available at the operator desk. This can be used to view a larger piece of the system when reviewing outages or switching that is needed. This enables the operator to have a complete view of a feeder zoomed out enough to see all the parts.
5. As controllable switches are added to the system, getting the FLISR tool would be beneficial. FLISR can provide recommendations for switching in response to a fault. FLISR can take into account remotely controllable switches only or manual switches as well. FLISR can also be set to run automatically for certain feeders where there is confidence in the accuracy of the system knowledge and accuracy of FLISR. This enables the operator to focus on getting the fault located and repaired.
6. An advanced data historian (ADH) can provide better insight into the system flow data per feeder and feeder segments and allow better analysis of system faults. As the number of devices and amount of data continually increases, an ADH makes it more manageable and provides better organizing and exporting tools.

3.3.2. Current and Future System Control Room and Distribution System Infrastructure Investments

1. According to the DERMS 2.0 definition, Distributed Energy Resource Management System (DERMS) - A DERMS is a hardware and software platform to monitor and control distributed energy resources (DER) in a manner that maintains or improves the reliability, efficiency, and overall performance of the electric distribution system. It provides the following functionality:
   a. Aggregates individual DERs—from single assets to grid-wide resources—to enable simplified control, monitoring, and management.
   b. Provides simplified data presentation of the granular details of DER assets, such as settings and performance, and presents DER capabilities as grid-related services consistent with the distribution management system (DMS).
   c. Automates individual and aggregated DERs by way of managing and coordinating settings and enacting DER response algorithms in conjunction with DMS requirements.
   d. Provides operational information for individual or aggregated DER assets to the DMS.
   e. Provides forecasts of DERs.
2. Although MHD does not have many DERs at this time, this may change quickly over the next few years. A DERMS can be easily added to or interfaced with the MHD SCADA system. The software will enable MHD to monitor and control DERs as well as analyze their performance and visualize how they all interact and how they affect the MHD system. It will enable MHD to keep their distribution system operating reliably even as the system becomes more complex with energy moving around differently than the existing flows.
3. As DERs are added by customers, they may provide capacity on a feeder that needs to be managed. This may require a separate function on SCADA but will most likely be included with DERMS. However, the SCADA system will need to have information on the DER output of each feeder and be able to decide when the DERs should be storing the power rather than putting it on the feeder.
4. The functions of the DERMS that will be used by MHD are not fully known at this time. The IESO and the OEB are still in the process of determining what the future market will need to look like to support a much larger number of renewable resources on the transmission grid and DERs on the distribution system. The regulators are examining an energy market on the distribution side, which could potentially be managed by the LDCs or at least require communications with he LDCs. In either case, MHD will have to be ready to monitor and control a much more complicated distribution system. This will require continuous learning by control room operators and MHD engineers. This will work more efficiently with dedicated in-house on desk operators.
5. Grid-Edge monitoring of equipment will also become more important as most new equipment provides extensive monitoring and data gathering capabilities. This may be key to monitoring the controllable switches and their sensing devices to ensure longevity.
6. Advanced Data Analytics (ADA) are becoming important as a way to make use of the wave of data that can be provided by new field equipment that comes with advanced monitoring. An advanced historian can also provide input to data analytics as utilities try to make better use of their system data gathering facilities and maximize the life span and functionality of their facilities. With the smart meter database, additional data from feeder equipment and DERMS, and additional data from a SCADA advanced historian, there will be many opportunities to use ADA for equipment health assessment and even feeder health assessment.
7. Artificial intelligence is going to become important to managing the DERs in the grid. This may be something that MHD needs when seeking to optimize the use of DERs and their storage capability taking into account reliability and market needs. AI will help identify the patterns and choices that optimize the system and may end up being an add-on to DERMS. MHD may be required to provide data to the user of the AI even if MHD doesn't have the AI itself. AI may end up part of OMS to improve its response and accuracy. In order to make the best use of AI, MHD will need control room operators with experience and real intelligence. The problem with Artificial Intelligence is that it is not always clear why it is making its recommendations. It can be hard to

spot bad recommendations. An operator with system experience and understanding may be able to spot and stop the implementation of a poor recommendation by AI. This kind of experience and understanding comes with dedicated on desk operators.

8. Demand Response may also become an important tool once again on the path towards the Sustainable Grid. The Grid will require extensive optimization of the energy supply to provide enough energy and maintain system stability. Being able to also manage the system Demand in addition to what is provided by DERMS, will also provide significant power that can be controlled to react to system contingencies and potential capacity issues. For Demand Response to work best requires responsive demand, that is, customers that are able to adjust their load requirements based on the price of the energy e.g., flexible charging of electric vehicles depending on pricing.
9. The future will also bring a growing number of electric vehicles and the need to charge them. MHD will see an increasing number of home chargers, business charging points and fast chargers at fill-up stations. These may be installed with BESS systems to balance the demand on the station. There may be a need for an application to monitor and balance these charging locations including the need to balance the time of home charging. Applications for these may be run by third parties but may also be needed by MHD to ensure their system loadings are managed carefully including the burden on the typical distribution transformer. Studies have shown that two people charging their electric vehicles overnight may prevent the distribution transformer from cooling down at night and thus shorten its life span. This will require flexible charging and perhaps a flexible market for charging energy.

3.3.3. Changes in System Control Room Functions and Required Skillsets

1. As distribution applications are being added, the operator will be required to be able to understand and use them. For example, FLISR can partially automate outage restoration but can also be used to provide recommendations. The operator will already have an understanding of the use of switches to partially restore power but will also need to understand the FLISR interface. The operator will need to understand the basics of the Power Flow program to be able to understand when its calculations are not in harmony with the feeder measurements.
2. The simulation tool can also be a powerful tool for testing out switching and its effects on the system.
3. There are a number of other tools that will be added that will provide information for engineering of the power system, and not directly to the operator. However, an operator may receive recommendations from these systems and needs to be able to understand the system well enough to know when the recommendation should not be followed. This will require each operator to be continually trained in the new tools to be able to understand how they function and how they are to use them. Understanding these new tools will likely require a mathematical understanding of the distribution system in addition to the current physical understanding of it.
4. There will also be a large number of applications to monitor to ensure that they are functioning properly. There will be alarms from these applications when they are having issues and the operator will need to have enough understanding of the application and the alarms to be able to respond.
5. Currently the main skill for the operators is to have an understanding of the physical power system including how to understand it electrically and how it is represented on screen. The recommendations and reactions they must take are primarily based on a physical understanding of the power system as power flows from the transformer stations down to customers. A number of the applications to be added will require a mathematical understanding of the power system and how to optimize it as the power flows may change direction because of DERS and BESS. The operator will not be performing the optimizations but will need to be able to recognize when the recommendations or the system measurements don't make sense. Some operators have a basic mathematical understanding of the system in terms of the proper voltages and feeder loadings but will need to have another level of understanding of the system optimization. Sometimes the DERs will be providing power to customers, while at other times the DERs will be

charging BESS and at other times both DERS and BESS will be providing power. On top of this there will be some power demand/load management that may also affect the power flow and direction. The timing of these types of behaviour may depend on the weather and peak energy use times but also may be affected by contingencies on the larger system. The operator will need to learn to how to understand these situations, and what actions they may to take and how to know when to take those actions.

6. The main skill then will be trainability and learning of new applications and new tasks as the applications are added to the system. This will also help as DERs, BESS, and charging loads are added to the distribution system and increase its complexity. This training and learning can best be handled by dedicated on desk operators.

APPENDIX A

Control Room Requirements

The following are the high-level general requirements for the building of the control room:

1. The Control Room shall take up the width of the room (approximately 40 feet across) and about 20 feet (6 meters) wide. This will provide enough space for at least two operator consoles and potentially 3 in future.
2. The War Room shall be adjacent to the control room and shall be the width of the room (approximately 40 feet across) and about 4 meters wide. The war room will provide space for a supervisor's desk and a long table to be used for work discussions with field crews and to provide 3 SCADA view only workstations with one large monitor for additional non-operating staff to use during major outage events.
3. There will be a wall between the control room and the war room. There will be a wall separating the war room from the rest of the large room. It may be necessary to have two doors.
4. Each room shall have a door that exits out away from the southwest side of the building to facilitate exit.
5. The door to the control room shall have controlled access requiring fob entry.
6. Each room will have HVAC facilities but with the temperature control in the control room.
7. Each room will have standard lighting facilities except that the lights in the control room will have some dimming capabilities.
8. Each room will have fire suppression facilities.
9. The control room will have two operator consoles with sit stand capabilities as described in Appendix B.
10. The space on the long wall in the control room to the right of the doorway to the war room will be used for placing and pinning paper maps of the MHD distribution system. These paper maps currently exist at MHD in another room currently used by operations staff. That room also has a SCADA workstation that is used primarily for viewing and working with OMS and a large display that shows the current SCADA/OMS display. The war room will have a similar set of maps on the other side of the wall that are not pinned but are used for review during handling of large outages.
11. Each operator console will have two console based light fixtures above it that are supplied from UPS. These lights will have a dimmer switch that is located on the console.
12. Each operator console will have local environmental controls for heating and cooling. These will be provided as part of the console equipment.
13. MHD will provide ergonomic chairs for each console.
14. The war room will have a working desk for a potential future supervisor or for working on the SCADA system in support of the war room team. The details of the supervisor desk are provided below.
15. The war room will also have a long table (currently in another room) that will be used for working on large outages or for meetings with field crews to discuss field work and Orders to Operate. This will have 8 chairs provided.
16. The long table will have at one end, 3 SCADA view only workstations provided with one large monitor each. These will be provided with enough space for working on outages while leaving room at the other end for laying out drawings for discussion of field work.
17. There will be a false ceiling provided above the control room and the war room. The electric circuits and computer network cables shall be routed over the false ceiling and then run into the room using drop down pillars.

APPENDIX B

Operator Console Requirements

The operator consoles should have the following basic features:

1. Sit/stand consoles with motorized adjustments
2. Display support structures that can hold at least 4 thirty inch displays with the option for two additional displays on top and shall allow the angle and height of the monitors to be adjustable.
3. Local task lighting
4. Local fans/heaters that facilitate continuous air movement locally
5. Power supplies and power bars in each work spaceworkspace to accommodate up to 2 computers, 6 monitors and 6 other powered desk devices
6. Space for at least 2 computers and other equipment at the back underneath
7. Provide internal cable trays and cable handling suitable for a sit/stand console
8. Storage space for documentation
9. Meet Ergonomic standards
10. General console features

Further details of the console requirements are provided below.

1. Sit-Stand – Each console shall be a sit stand console with the following features:
    a. It shall be possible to adjust the height of the console work surface and monitors from a sitting height to a standing height. The console shall have a range of 28 inches above the floor up to 50 inches above the floor.
    b. It shall be possible to adjust the height of the monitors separately from the height of the work surface. It is preferable if this involves separate height control for the operator work surface and for the monitor support section. Alternatively, it is permissible for the monitor support and work surface to be one piece that moves up and down together but also have a control just for moving the monitors up and down while the work surface doesn't move.
    c. The console must use at least two columns for supporting the work surface and/or for supporting the display support section if separate from the work surface support.
    d. The work surface shall be able to support a keyboard and mouse for the SCADA computer, and a keyboard and mouse for the corporate PC, one SCADA telephone, one SCADA radio set, a corporate telephone, at least six 2-inch documentation binders and two operators leaning on the work surface.
    e. The raise/lower system shall operate quietly making a noise of less than 30 db (e.g., the level of whispering).
    f. The speed of raise/lower shall be at least 0.5 inches per second.
    g. The console shall have special handling for cables so that cables don't get pinched or tangled during raise/lower operations.
    h. The operator shall be able to operate the raise/lower mechanism(s) through a switch(es) that is reachable from a normal sitting or standing position. As an option it should also be operable by hand.
2. Display support structure – Each console shall have a display support structure that meets the following requirements:
    a. The display support structure shall be able to hold at least 4 thirty-inch displays (three for SCADA, one for corporate) plus two additional smaller displays above.
    b. The display support structure shall allow the vertical and horizontal angle of the displays to be adjusted individually as well as in a group. It will be permissible to only provide for the vertical tilt of the 4 30-inch monitors to be adjusted since they will be usually grouped together and treated as one screen for display of various displays. However, it shall be possible to also tilt the outside 30 inch monitors inward to have a better line of site to the user. The range of vertical/horizontal motion shall be 30 degrees.

c. It shall also be possible to move the monitors closer to the user. The range of motion shall be at least 9 inches.
d. As noted in the previous requirement, it shall be possible to raise/lower the display support structure as part of the sit/stand capabilities.

3. Local Task Lighting – The console shall provide local task lighting that meets the following requirements:
    a. The task lighting shall evenly illuminate the work surface.
    b. The task lighting shall be adjustable so that the light intensity and angle can be adjusted to suit the natural and overhead light conditions and operator preference.
    c. The task lighting shall not interfere with the viewing of the monitors e.g., there shall be no glare caused by the task lighting.
    d. The task lighting shall meet the proper CSA approvals.
    e. The task lighting shall provide normal white light.
    f. The task lighting shall use energy efficient lighting technology.
    g. The task lighting fixtures shall be resistant to shocks and vibration caused by normal work and by the operation of the fans and heater and the raise/lower mechanism.
4. Local fans/heaters – Each console should have its own local environmental control system as follows:
    a. A fan(s) shall be provided to circulate air below and above the work surface.
    b. The air shall circulate in a way that provides continuously moving air at the breathing level but does not normally provide a draft unless the user selects a high enough fan speed to produce a draft.
    c. The system shall include a filter to remove dust particles from the air.
    d. The system shall include a heater to provide warmth that is circulated by the fans.
    e. A control panel shall be provided that mounts under the workspace surface. The control panel shall allow the operator a broad range of air flow and a broad range of heat. The operator shall also be able to adjust the air flow separately above and below the work surface.
    f. The fan noise at the operator head level shall be less than 30 db with the front panels on i.e., it is expected that the environmental system shall be located inside the console structure.
5. Power supplies and power bars – Each console should be provided with enough power supplies and power bars to accommodate up to 3 computers (e.g., an additional plugged in laptop), 8 monitors and 6 other powered desk devices (i.e., at least two radios, powered speakers, calculator, telephone) and the console equipment as follows:
    a. The consoles shall supply two 120 Volt AC UPS power supplies to each console location preferably from separate distribution panels.
    b. Each console shall be supplied with 2 heavy duty power bars that can supply at least 2 power bars each with 6 to 8 plugs in each. The lift/lower motors and environmental system should not be on the same power bar as the computers. The lift/lower motors and/or environmental systems shall not interfere with the quality of the power supplying the computers. It is assumed that the lift/lower motor and local heater draw a lot of power and should not be operated when on UPS power.
    c. The console shall provide four 24/7 rated CSA approved power bars, 2 plugged into each heavy duty power bar.
    d. The power bars shall supply the MHD provided equipment as well as the raise/lower mechanisms, the task lighting, and the environmental control equipment.
    e. The equipment shall normally be evenly split between the power supplies. However, in case of failure of one power supply, it shall be possible to easily relocate the plugs for each device into a still working power bar. This allows for 17 MHD supplied devices and 7 console devices (i.e., raise/lower mechanism, environmental controls, task lighting).

6. Equipment space inside the structure – the console shall provide shelves for computers inside the base of the console for at least 2 computers and potentially other equipment that meet the following requirements:
    a. The computers will be placed on slide out shelves that can handle the weight of a desktop size computer plus cable attachments.
    b. The slide out shelves will allow the computers to be easily accessed for maintenance (e.g., updating of software through local CD ROM or memory stick, or recabling) once the back panel is removed or swung open.
    c. The slide out shelves will also have access to internal cable trays for connecting the computers to their respective monitors, keyboards and mouses and power bars.
    d. The internal design of the console will maximize the separation between power cables and signal cables.
    e. There must also be space for other potential equipment inside the console e.g., radio base station connected to radio on the work surface. The vendor shall propose how this will be handled.
7. Internal cable trays and cable handling – The consoles shall meet the following requirements:
    a. The console structure shall provide for efficient cable management of all power and signal cables, preferably in internal cable trays.
    b. The cable trays shall extend throughout the console to allow complete management of cables.
    c. Cables connected from internal equipment to monitors and work surface tools shall be routed through flexible cable trays or ducting that prevents pinching of cables.
    d. Raising and lowering of the work surface and/or monitors shall not cause any cables to be pinched or pulled loose.
8. Storage space for documentation – There must be shelves in the consoles to accommodate several 2-inch binders (e.g., documentation of the SCADA, procedure books) that meet the following requirements:
    a. This should be set back in so that it doesn't interfere with the operator's legs when they turn to work on this surface but shouldn't be too far under that it is hard to reach.
    b. There must also be one shallow drawer in the console that is used for miscellaneous working supplies e.g., pens, pencils.
9. Ergonomic Standards – The consoles shall meet the following requirements:
    a. The consoles shall be designed to meet the requirements of ergonomic standards such as ANSI, BIFMA, CSA and ISO, specifically, ISO 11064-4, Layout and Dimensions of Workstations.
    b. The working area shall follow human factor criteria in the design of the knee space, monitor view angles, reaching distances, and keyboard and mouse use.
10. General Console Features – The consoles shall meet the following general specifications:
    a. The consoles shall be of modular construction so that it is easy to assemble and disassemble and replace broken or damaged parts.
    b. The console shall have a metal frame construction with exposed surfaces normally made of engineered wood (e.g., press board) with an aesthetically pleasing veneer.
    c. The metal frame shall incorporate the raise/lower mechanism(s).
    d. It shall be possible to remove the exposed surface panels at the back and front without the use of tools.
    e. There shall be no sharp edges in the console metal frame or on the exposed surfaces.
    f. The working surface shall also have smooth and curved edges with no sharp corners.
    g. The consoles shall have a means of ventilation for the internal electronic equipment that is separate from the operator environmental controls. The heat can be ventilated out the back.
    h. The console frame shall include leveling feet to ensure that the console and work surface can be perfectly level for the long-term health of the raise/lower mechanism.

APPENDIX C

Control Room Building and Commissioning Estimate

The following is an email from Black and MacDonald with the budgetary quote for the control room. AESI has added $2,000 to include dual UPS circuits to the operator consoles and the supervisor's desk.

Black & McDonald

February 3, 2022

Milton Hydro
200 Chisholm Drive
Milton, Ontario

Attention: Richard Ganton RichardG@aesi-inc.com

Subject: **Budget New Control Room**

Dear Richard,

We are pleased to submit our budget pricing to complete the following scope of work:
S&I new 4'-0" x 4'-0" concrete base slab at ground level for new condenser unit
S&I (3) - 3'-0" x 7'-0" new interior 18ga interior hollow metal doors and frames c/w required door hardware
S&I (1) - 3'-0" x 3'-0" interior hollow metal window frame c/w tempered glass
Construct interior demising drywall partitions to create Control Room, Office area and mechanical room (95 LF of partition at a height of 20'-0")
5/8" type x drywall full height both sides
6" - 20 gauge steel studs at 16'oc
Batt insulation
S&I new 2 x 4 acoustical ceiling tile and grid (Control room & office only)
S&I 24"x24" carpet tile and bound carpet base at to Control room & office only
S&I (1) primer coat and (2) finish coat of paint to new and existing drywall and new hollow metal doors and frames
Complete drawing for permit submission
Permit application

Electrical Mechanical work
Engineering calculations, drawings, and specifications, for HVAC and electrical (power, exiting, lighting, emergency lighting) design and drawings
Power outlet15A each at each desk (3 total). Allow for outlets along existing and new walls for general use
Allow for breakers for new power requirements (lighting, outlets etc.)
Allow for power wiring, light fixtures & Emergency lighting , exit signs
Allowed for new gas furnace with venting to outside & air conditioning system. Assumed 4 ton system
Allowed for placing new condenser at ground level
Allowed for gas supply from within the Control room gas supply line
Allowed for ducting for new system for control room & one office with one thermostat control
Supervision

FOR THE BUDGET SUM ……………………………………………………………………………$350,000.00 + HST

The following items are not included in our scope:

Sprinkler and Fire Alarm by Milton Hydro
Door Access hardware and Security systems by Milton Hydro
Connecting to existing BAS or programming

Please call me if you have any questions.

Black & McDonald

Mike

MIKE COLALILLO | Project Sales Representative
Black & McDonald Limited

Tel: (289) 975-7845 | Fax: (905) 662-5882 | Cell: (905) 971-3605
328 Green Rd, Stoney Creek, ON, L8E 2B2

Black&McDonald

100 Centennial 1921–2021

APPENDIX D

CONSOLE ESTIMATE

The following is the budgetary quote from Tresco Consoles. The quote was rounded down to $70,000.

AESI Inc.

Ontario Utility - 2 consoles
January 14, 2022

Proposal	**16641**	**Tresco Rep:**	**Evan Turner**
Dwg Rev	**N/A**	**Direct Line:**	**403-538-8332**
Attention:	**Richard Ganton**		**eturner@trescoconsoles.com**
Series:	***2400***		

Single Operator Console **Dwg #:**

Qty	CONSOLE #1 Description	Unit	Total Cost
5	**24" Desktop Module (full or reduced depth)** - worksurface and exterior panels covered with high-pressure plastic laminate. - front and rear access doors mounted on hanging clips or hinges.		
	Frame Costs		$9,525.46
>	**Accessories**		
2	Ventilation Fans w/ Louver Cut-out on worksurface or rear apron	$250.80	$501.60
10	Multifunctional Back Wall with Laminate Finish Standard Height	$212.52	$2,125.20
4	Single Arm on 14" pole with mount (Tresco Arm SAA 1)	$444.89	$1,779.56
2	Large Overview Monitor Articulating Mount (no additional support under worksurface)	$1,426.31	$2,852.62
1	Adjustable Task Light (worksurface or slat mount) Z Bar Gen-3	$429.00	$429.00
1	Flip-Up convenience outlet (1) Electrical/1 USB A + C	$167.01	$167.01
3	Standard Power Bar 6 receptacle	$151.80	$455.40
10	2" x 4" Wire Tray (per linear foot)	$49.50	$495.00
1	Mobile Pedestal	$990.00	$990.00
3	Adjustable Worksurface Kit - Electro-mechanical (per DL2 column)	$1,623.60	$4,870.80
3	Vertical Cable Management (each)	$132.00	$396.00
1	Personal Environment System - Circulated Air includes: - baseboard heater - air diffuser (on/off only) - white noise generator - occupancy sensor - control pad (wired) and (2) convenience outlets - includes backup Worksurface Integrated Control Pad for set up and trouble shooting	$4,218.72	$4,218.72
1	Rack Mount Rails (Included in frame pricing)	$0.00	$0.00
3	Sliding Equipment Tray (Included in frame pricing)	$0.00	$0.00
Subtotal Console #1			**$28,806.37**
		Qty	**2**
Total Console #1			**$57,612.74**

SUBTOTAL CONSOLES WITHOUT OPTIONS (EXW Tresco)	**$57,612.74**
Palletizing and Crating	**$2,761.00**
Shipping to: Toronto, ON	**$2,493.38**

- shipping quotation valid for 30 days from proposal date; actual may vary +/- 15%
- assumes availability of a loading dock capable of accommodating a 53' truck
- additional charge will apply if delivery via lift gate or a fork lift rental is required
- additional charge will apply if time scheduled delivery is required
- additional charge will apply if Tresco's installers must receive product
- if buyer is responsible for shipping, a "Loading and Documentation" charge will apply

FCA: Goods are delivered to the named place by Tresco; Buyer is responsible for unloading the goods from the carrier at the named place and loading onto buyer's facility or their own carrier (if applicable). Additional charges may be incurred if delivery must be scheduled to arrive at a specific time.

Installation by Tresco Certified Installer(s)	**$7,331.94**

- safety courses, background check or drug & alcohol testing not included
- based on an 8 hr. working day
- assumes (1) installer on-site for up to (3) days
- for single installer projects, a qualified buyer provided helper(s) will be required on-site to assist with team lifts; helper(s) must be available for the duration of the install as needed. If no helper(s) are provided, additional charges will apply. Alternatively, Tresco can quote two installers.
- assumes working on weekdays, during normal daytime hours
- assumes working on Sat and Sun for installations that run through weekends
- additional charges may apply for weekend travel or installation days
- assumes single installation activity, non-union site
- site labor/hours reporting and associated administration not included
- pending verification of site conditions

(WHT: services related withholding tax is **not** included and will be calculated in addition quoted amount, Buyer must advise Tresco prior to release of PO)

Total Before Tax	**$70,199.06**
13% HST	**$9,125.88**
TOTAL CAD$	**$79,324.94**

ADDITIONAL OPTIONS

Sitting Fee (per day, per installer)	**$1,980.00**

- applicable for each previously scheduled and agreed upon work day in which dispatched installers are not permitted to work
- installation rate is based on Tresco being permitted to work consecutive days at site, and also through weekends for installs over 5 days
- sitting fee covers installer's hotel, food, transportation, flight rebooking

TERMS AND CONDITIONS (Rev 13)

Issuance of a Purchase Order confirms Buyer's understanding of an agreement to all Terms and Conditions itemized below. Any modifications to Sellers's Terms OR substitution of Seller's Terms with Buyer's Terms must be agreed to by Seller in writing.

1.0 General

1.1 Tresco Industries Ltd. (Seller) is incorporated under the laws of the province of Alberta, Canada and operates according to all current labor and tax laws.

1.2 Costs associated with local, state or provincial and federal taxation legislation remain the sole responsibility of the Buyer.

1.3 Price quotations are valid for a period of six months from the date of issue unless otherwise indicated in writing.

1.4 Shipping quotes are valid for a period of thirty days from date of issue unless otherwise indicated in writing.

1.5 Console modifications after placement of Purchase Order will be subject to price adjustment via Change Order.

2.0 Equipment Mounting

2.1 Each console price quote is based on an approximate design concept. Dimensions of all equipment to be loaded into, or placed on, the console will be required to determine the final, engineered design. Any change to, or addition of, equipment and/or mounting requirements may incur additional charges for console design modifications or custom engineering.

2.2 Monitor Mounts are not provided with bolts and/or screws to attach buyer monitors to the VESA brackets. Seller is able provide bolts and/or screws and spacing washers, only if specific details of the hardware required are provided by the buyer (i.e. length of bolt, M6, M8, etc.).

3.0 Room Dimensions

3.1 Buyer is responsible to provide Seller with confirmation of exact room dimensions. An As-Built CAD drawing will always be preferred but in the absence of a digital file, a PDF document, Visio file, or hand sketch will be acceptable. If a PDF, Visio File, hand sketch and/or written room dimensions are provided by Buyer they must be accompanied by a written confirmation/indication of accuracy. Room layout drawings must show the placement and size of doors, windows, columns, existing furniture and any other fixtures that might impact console configuration and/or placement in the room.

3.2 At the Buyer's request, and at Buyer's expense, Tresco can send a representative to site and determine as-built dimensions of the space.

3.3 If Seller utilizes room dimensions provided by Buyer to design console(s) and the room dimensions prove to be inaccurate and, as a result, the console(s) does not fit into the room, all costs related to reparation will be the responsibility of the Buyer.

4.0 Scheduling

4.1 Upon the receipt of Purchase Order, Seller will establish a formal production schedule.

4.2 Seller's production schedule will include milestone dates for Buyer design input and drawing approval.

4.3 Buyer milestones include:

Proposal Drawing Signoff including color selection and submittal of equipment specifications (model# and/or dimensions) and mounting requirements

Site Condition and Logistics Confirmation

4.4 In order for Seller to meet scheduled production milestones Buyer must meet design input and drawing approval milestones.

4.5 Consoles will ship approximately 8 – 12 weeks from receipt of Shop Drawing approval unless an alternate production schedule is confirmed in writing. Actual production schedule will dependent in part on project scope.

4.6 Procurement of parts and materials necessary to complete the order will commence upon receipt of the Buyers Purchase Order. Any change request with regard to material specification i.e.) laminate color after placement of Purchase Order may result in additional charges.

5.0 <u>Shipping</u>

5.1 Seller has developed a reliable working relationship with several carriers that understand the manner in which the Seller's consoles must be handled in order to arrive in good condition. For this reason, Seller recommends that the Buyer allow Seller to select the shipper and take responsibility for the safe transport and delivery of the consoles and associated millwork.

5.2 Shipping quotes are valid for a period of thirty days from date of issue unless otherwise indicated in writing.

5.3 The shipping quote assumes a single shipment of all deliverables unless otherwise stipulated in client specifications or agreed in writing. If additional shipments, expedited shipments, or storage of the materials are requested by the Buyer, additional costs will be the responsibility of the Buyer. Seller will provide a quotation and submit Change Orders as required.

5.4 If Buyer receives goods in the absence of a Seller's representative (most commonly a furniture system installer), the Buyer assumes responsibility for the safe unloading and storage of items in shipment.

5.5 If there is damage to the crates, the crating should remain sealed and not opened to prevent further damage. Any damage incurred during shipping must be noted on shipping documentation and reported to Seller immediately upon receipt. Any damage not reported at the time of delivery will not be covered by Seller's warranty and will be presumed to be the result of improper storage or handling. Damage repair and/or component replacement will be at Buyer's expense.

5.6 Seller's pricing assumes that a tractor trailer unit of 75' total length will be able to deliver product to Buyer's loading dock. If a loading dock and/or fork lift is unavailable for the purpose of receiving Seller's product shipment, it is the responsibility of Buyer to notify Seller. Additional charges may apply.

5.7 Seller's price quote, unless otherwise indicated, does not make allowance for cross-docking, fork lift rental, extra labor or any other expenses that may be incurred to complete delivery of finished goods to site.

5.8 Unless otherwise agreed to within proposal the Buyer assumes all responsibility for ensuring that the necessary equipment is available at site to unload the consoles and provide for disposal of packing materials.

5.9 Unless site delivery conditions are disclosed to Seller before the contract price is finalized Seller reserves the right to charge to Buyer's account additional expenses related to delivery, offloading or packing materials disposal.

5.10 Should unionized labor be required for any part of the work associated with delivery, unloading or placement of Seller's product, Seller will require payment from the Buyer for the additional charges on a cost plus 15% basis.

5.11 The Buyer may elect to assume responsibility for the safe transport and delivery of the consoles. In this case, Seller will supply the ship date and customs documentation. Shipping and logistics arrangements will remain the sole responsibility of the Buyer. Responsibility will rest with Buyer to procure appropriate insurance coverage. Costs of repair/replacement to rectify damage sustained in transport will be the sole responsibility of Buyer.

5.12 A factory pre-shipment inspection should be conducted by Buyer choosing to ship through their own carrier. Should the Buyer not choose to conduct an inspection of the goods prior to the loading and shipment of said goods, the Buyer deems the goods to be satisfactory and undamaged.

5.13 For shipments within North America, Seller does not palletize frame sections. Should the Buyer wish to have frame sections palletized, Seller must receive notification in writing at time of Purchase Order otherwise additional crating charges will apply.

5.14 For Shipments into the United States of America, Seller is required by US Federal Law to provide the Buyer's Federal Tax Identification number on Customs documentation. Buyer will be required to provide Seller with this information prior to shipment.

5.15 IMPORTANT NOTE: The Federal Tax ID number must be provided a minimum of 2 weeks before the scheduled ship date. If the Federal Tax ID number is not received by Seller at least two weeks prior to shipment, Seller reserves the right to delay shipment until the Federal TIN is received from Buyer.

5.16 Domestic shipments (Canada and USA) – Ownership of products transfers from Seller to Buyer at the moment the freight truck pulls away from Tresco's loading dock unless otherwise stipulated in client's acceptance terms.

6.0 Site Preparation

6.1 Installation and shipping quotations assume clear, unobstructed access from the point of offloading to the installation site.

6.2 Installation site must be clean, clear, and prepared for the installation of materials upon their arrival. All construction including flooring, walls, ceiling, lighting, electrical work, painting, and carpeting must be complete prior to the arrival of the consoles.

6.3 Any costs associated with delay of console installation due to site conditions will be charged to the Buyer.

6.4 Seller's installation quotation assumes that the Buyer will appoint a representative that will be available to direct Seller's installation team with respect to security, site safety, and console placement.

6.5 Unless specifically indicated, Seller's price quotations makes no provision for special permits and do not include a provision for installer requirement to attend site safety meetings and/or orientations. Additional time and/or costs associated with either of these requirements will be the sole responsibility of the Buyer.

6.6 Seller will not provide professional architectural design, electrical engineering or mechanical engineering unless otherwise agreed as a subcontract item. Seller shall be held harmless for such work performed by others based on design recommendations offered by Seller during the course of the project.

7.0 Payment Terms

7.1 Upon receipt of Purchase Order, Seller will conduct a credit review. Buyer must provide three (3) credit references as well as complete company contact and project data as requested along with a hard copy of the Purchase Order.

7.2 North America – Payment Terms

Subject to a satisfactory credit rating, payment terms are as follows:

For Console Orders:

20% of the total contract value upon Seller's acceptance of Buyer Purchase Order - Net 15

Balance of payment (incl. pre-shipment Change Orders) upon Seller's "dock ready" date - Net 30

For Part/Accessory Orders:

100% payment at time of Purchase Order

7.3 International Payment Terms

Subject to a satisfactory credit rating, payment terms are as follows:

100% wire transfer of funds at time of Purchase Order

7.4 Should the results of the credit investigation fail to meet Seller's standards for extending unsecured credit, Seller will notify Buyer and indicate acceptable payment terms.

7.5 For shipments outside North America payment in full via wire transfer will be required before product will be released for shipment. Any additional charges will be for the Buyer’s account.

8.0 Cancellation

8.1 Penalty to the end user for cancellation of the order will be waived if written notice is received by Seller within seven calendar days of Seller’s receipt of the Purchase Order.

8.2 After the seven-day grace period a cancellation penalty will be assessed according to the following schedule:

Pre-production - 25% of contract value

After start of production - 25% of contract value plus labor & materials at cost + 15%

9.0 Storage

9.1 If the Buyer requests storage of finished product prior to product shipment or if the Buyer requests a delayed delivery date, the value of the contract, not including charges for installation, will be payable within fifteen days of the date that Seller deems production to be complete.

9.2 Storage fees will be payable by the Buyer according to a payment schedule to be negotiated between the Buyer and Seller. Fees will accrue from the calendar day following the completion date.

9.3 Storage at Seller's factory will be subject to the availability of storage space.

9.4 Seller requires a minimum one-month advance notice to remove finished product from storage. Installation by a Seller factory trained representative will be subject to installer availability.

10.0 Installation

10.1 Installation will be performed by factory-trained, non-union furniture system installers.

10.2 The installation price quote includes the placement, installation and cleaning of the delivered product.

10.3 Installation activity does not include the loading of third-party electronics into the console, does not include electrical work of any kind and does not include installation of anchoring hardware.

10.4 Seller's installers will require unrestricted access to elevators and reasonable security access to the installation site. All costs associated with delays resulting from restricted access will be payable by the Buyer on a cost plus 15% basis.

10.5 Any on-site requests for additional work at installation site by Seller representatives will be subject to the representative's fitness for the work, the representative's travel schedule, and the approval of Seller's project manager. Additional charges may apply.

10.6 Seller has based its quotation for installation on the use of Seller's own factory- trained, non-union labor. Should unionized labor be required for any part of the work associated with the installation of Seller's product, Seller will charge Buyer for the additional installation costs on a cost plus 15% basis.

10.7 Unless otherwise stated, all parts of the order will be shipped so as to permit continuous installation activity. Unless indicated otherwise by the Buyer in writing prior to placement of Purchase Order or accounted for by issuance of Change Order, Seller's installation quotation assumes that the site is prepared to receive all materials and to allow Seller installers to fully complete the installation as a single activity.

10.8 The cost of multiple trips to complete installation as well as overtime and/or costs associated with delays caused by site conditions beyond the control of Seller will be charged to the Buyer.

10.9 An authorized representative of the Buyer is required to perform a final review and to give written acceptance of installed product immediately upon completion of installation, in order to verify that the product has been delivered and installed per Purchase Order specifications and to the satisfaction of the Buyer. Any deficiencies must be noted at this time. Deficiencies that are the responsibility of Seller will be rectified immediately.

10.10 The Buyer may elect to take responsibility for product installation. In this case Seller will require the execution of a Third Party Installation Agreement.

10.11 Installations in December may require an additional charge, in the form of a change order.

11.0 Warranty

11.1 Tresco consoles are warranted against defects due to materials and workmanship as follows:

LIFETIME WARRANTY on all structural frame components

LIFETIME WARRANTY on exterior panels, work surface and associated components

LIFETIME WARRANTY on all adjustable, sliding or hinged mechanisms

FIVE YEAR WARRANTY on all electrical components, including lifting columns

FIVE YEAR LABOR for replacement or repair of items under warranty

ORIGINAL EQUIPMENT MANUFACTURER WARRANTY for any 3rd party electronics that are not associated with the direc

11.2 The failure of any component as a result of a defect in materials or workmanship will be replaced or repaired at Seller's expense.

11.3 Seller's warranty is limited to the repair or replacement of defects in material or workmanship. Seller is not responsible for damage to delivered product during storage on site or following installation.

11.4 Delivered product must be stored and utilized in a secure humidity and temperature-controlled environment (not less than 25% and not more than 55% humidity, not below 55° F and not above 85° F) in order for Seller warranty to remain valid.

11.5 Seller shall not be responsible for repair or replacement of items that have been subjected to neglect, accident or improper use, or which have been altered by personnel unauthorized by Seller.

11.6 Products that are not unpacked and installed by a Seller representative will not be covered by this warranty as there is no conclusive way for Seller/Buyer to prove the origin of damage or missing parts.

11.7 If laminate is discontinued, the repair will only be to the damaged top or panel with a new finish selection of the client's choice. Warranty does not cover the replacement of undamaged panels to match the new plastic laminate finish.

11.8 Scratches and dents in stainless steel worksurfaces and panels will be considered to be the result of regular use and wear if they occur after the installation of the product by the Tresco Consoles installer and are not covered by this warranty.

Signature ____

Name (Please print) ________________________________

Organization ______________________________________

Date ____

APPENDIX E

Operations Cost Research

AESI conducted a salary survey of operators at similar utilities using publicly available sources in order to estimate an appropriate salary for an MHD operator. The following information was used to make that determination:

1. Hydro One Brampton: 5 Journeyperson Operators with average compensation (i.e., salary + overtime) of $167,271 in 2014.
2. IESO: 3 operator positions in 2020 (salary + overtime + shift premiums)
    a. Senior System Operator, 17 people averaging $189,148
    b. System Operator, 13 people averaging $175,322
    c. Assistant system Operator, 10 people averaging $148, 781
3. Sample Water System Operators in Ontario:
    a. Region of Halton: 2 water operators averaging $105,231 in 2020
    b. Hamilton: 7 water operators averaging $109,743 in 2020
4. The average salary for electric distribution system operators across Canada: $95,696
5. According to Government of Canada Job Bank, hourly wages for Electrical Station Operator - Electrical Power Systems are as follows:
    a. Ontario: Salary Low: $27.62, Median $43, High $60 per hour for a median salary of $89,440 and a high salary of $124,800.
    b. Alberta: Salary low $28 per hour, median $46 per hour, High $63 per hour
6. ATCO Electric: Distribution operator salary was $93,000 in 2013. Factoring in for inflation of 1.17, this salary would be $108,810 in 2022.
7. Powerstream System controllers in 2017 ranged from $28.42 per hour to start to $45.74 per hour after 5 years for top salary of $95,139. Factoring in inflation, this salary would be $107,710.
8. Oshawa PUC Operations Technician starting at $35.51 and as certified $46.75 in 5th year in 2017. Factoring in inflation, this would be $109,981 in 2022.

EXHIBIT 4

ATTACHMENT 4-3

RESOURCE OPTIMIZATION REVIEW REPORT

Marjorie Richards & Ass. Ltd.

RESOURCE OPTIMIZATION REVIEW

MILTON HYDRO

November 2021

Introduction

- Marjorie Richards & Ass. Ltd was engaged by Milton Hydro in September 2021
- The scope of the engagement was two-fold:
  - *Update its Workforce Planning analysis and information to feed into its upcoming COS Application process*
  - *To undertake Resource Optimization Review*
  - *Resource optimization is* ***the set of processes and methods to match the available resources*** *with the needs of the organization in order to achieve established goals*
- The Review was focused on positions and roles up to and including the director level
- The Report was based on one-on-one interviews with the senior team, and did not include a validation through an internal audit process
- The Review & recommendations are for Milton Hydro's consideration only, and it may or may not accept some or all of the Review's findings as part of its business planning

Review Overview

Milton Hydro's Resource Optimization Review ('the Review') has two distinct yet aligned focuses. Its trades and technical staff, inclusive of the front-line management required to lead and manage the trades groups, and, determining the right size and right skills of its management & professional staff over the next five years and beyond

The Review provides insight into what trends are impacting the labour market, and what and where Milton Hydro should/may focus on over the next five years to achieve its objectives and meet the changing demands of its Customers and Stakeholders. The Review does not include a review or recommendations on executive level positions

Milton Hydro has maintained a workforce 'well-below' the average of its other medium-sized LDC peers for the past number of years. The Review identifies where staffing needs to increase to: meet the rapid and sustained growth of the Town of Milton; protect worker and public safety; balance workforce utilization against optimization; and sustain an efficient workforce with the right tools and skills to be responsive to it Customers

Review Overview

As part of the Review, Milton Hydro considered the need to replenish its trades & technical workforce against its Principles & Assumptions, and the proactive initiatives it will employ to mitigate the ongoing risk of an insufficient or under-skilled workforce pipeline

The CEO and Board have a forward looking vision of the organization’s future and are developing a five-year Roadmap. Milton Hydro’s recommended *Optimal Structure* is aligned to its core strategies, and the future direction of the organization

We engaged Milton Hydro’s Senior Management Team (SMT), its Manager HR, and its Safety Professional to attain a thorough understanding of the current strengths and challenges, as well as affirming assumptions on functional business needs now, and into the future

The Plan conclusions are based strictly on data provided by Milton Hydro. We did not conduct an internal audit of the information provided

Workforce Optimization Goals

RIGHT SIZE

Not over or under staffed

Meet work demands with right labour supply

RIGHT UTILIZATION

Optimally utilize people, tools and equipment

Increase workers tool time on the job

RIGHT COST

Keep Customer Rates reasonable

Keep cost efficiencies top of mind

RIGHT SKILLS

All employees have right skills & capabilities to do the job

Re-skill or hire new skills as sector evolves

Manage Risk and Customer Expectations

What is Workforce Planning?

Workforce Planning ('WFP') takes a broad view of Milton Hydro's trades group, inclusive of those skills that are required to maintain and grow its distribution system and meet the changing demands of its Customers and Community over the next five years and beyond

Essentially, WFP identifies gaps between the labour *demand* of an organization and the available workforce *supply*, leading to initiatives and actions used to close the *gaps*

Matching the resource capability with the work demands in the electrical distribution sector requires both short and longer-term planning. Numerous contributing factors are impacting Milton Hydro's WFP, including:

- *An industry-wide shortage of skilled labour*
- *Emerging technological advancements that will change trades/technical know-how/skills*
- *Increased competition for new skills*
- *Increased work demands due to an ageing distribution infrastructure*
- *Responding to its rapidly growing Community and Customer base*

WFP Guiding Principles

- *Increase overall productivity* to ensure greater availability of productive time, while also establishing initiatives to gain efficiencies that increase the quality of the time worked
- Advance hiring of apprentices to ensure a ***consistent 'optimal' number of proficient trades & technical workers***
- Where available in the labour market, attract and hire qualified and proficient Line Persons, with the aim of ***reducing the overall required training investments*** in apprentices and ***leverage qualified resources with a shorter lead time to achieve maximum productivity***
- Balance hiring with the appropriate use of overtime to supplement labour gaps, and continue to leverage contracted services, where ***cost effective and when there is a labour supply demand***
- *Increase the efficiency* of work through innovative practices and the introduction of new technologies and automation

Market-Driven Trends

Industry Outlook

The electricity distribution sector in Ontario continues to evolve and transform at a rapid pace, driven in a large part by technological changes. The industry is adapting to major technological changes including the greater use of Information & Communications Technologies ('ICT'), smart grid applications, renewable technology integration, the electrification of transportation and the decentralization of Distributed Energy Resources (DERs)

The industry is challenged with investment in ageing infrastructure while at the same time modernizing the grid to make it more responsive to customers, meeting two important objectives – the system will become more efficient and people will have more control over their energy use and costs[1]. Disruptive technologies are transforming how the electrical system is built, maintained and operated through digital technology. As such, the skills and competencies of the past are evolving and becoming far more complex and innovative

1 - CEA's Vision 201 – Future of Canada's Electricity System

Market-Driven Trends

Industry Outlook

With the proliferation of advanced technologies such as remote sensors, data analytics, automation and unmanned aerial vehicles (UAVs), LDC's are now evaluating how to plan, build, operate and maintain utility assets and how to serve customers who are more savvy, knowledgeable and seeking control of their generation, distribution and use of their energy needs

The role of the energy consumer is also rapidly changing. Customers are more empowered and tech savvy, seeking personalized and relevant on-demand services, as well as smart home ecosystem solutions. Customers are no longer simply users of electricity - through participation in load and energy reduction programs - they have become electricity suppliers

Digital transformation is enabling municipalities to modernize services in a way that makes delivery more efficient and more citizen-centred. *Electric services need to be available quickly and easily on-line in a way that meets new consumer demand, in real-time and real fast*[2]

2 - Electricity Human Resources Canada Report, Work Transformed, the Impact of Technology 2020

Market-Driven Trends

New Technologies & Expertise

According to Electricity Human Resources Canada's *Workforce in Motion* Report, "as the sector becomes more sophisticated, demand will increase for employees able to work in an ever-changing, diverse, interconnected and high-tech electricity sector. To meet labour needs, businesses will become more reliant on recruiting employees with transferrable skills from other industries, particularly those in Information and Communications Technology"

Researching precisely what these advanced skills will be remains challenging, in part because the requirements and need for new infrastructure in a digital transformation is still evolving. The following provides some insight into the skills and expertise Milton Hydro will need to build and work with the union to develop over the next few years, to be prepared for the near future

Data Analyst	A data analyst in the digital world looks different than current LDC Database Analysts. They collect and store data on logistics, inventory, market research, and other intelligent behaviours. They bring technical expertise to ensure the quality and accuracy of that data, then process, design and present it in ways to assist Customers, businesses and the organization make better decisions
Intelligent Network Control Operators	Network Operators need to be more predictive and intelligent. They will enable LDC's to transform current operating models into a Digital Platform Organization that delivers better value to Customers and interacts with a plethora of digital devices and systems (both inside and outside of the company interfaces)

Market-Driven Trends

New Technologies & Expertise

A scarcity of digital skills and internal barriers related to company culture and mindset are the biggest roadblocks hindering digital progress in the energy sector, with 71% of organizations in the industry needing employees with combined domain and digital experience and 18% claiming to not have a single employee with this combined skillset.

These are just some of the findings from the new DNV GL Report - Digitalization and the Future of Energy, which surveyed nearly 2000 engineers and senior executives from start-ups to large corporations in the energy sector

Market-Driven Trends

Labour Market Shortage & Competition

An adequate pool of trained and experienced workers is important in terms of ensuring the long-term stability of the electricity supply. Modernizing the system improves how power is stored and distributed, and it also provides jobs for workers who have the right skills and training

The electricity sector is not a 'just in time industry'. The workforce is highly skilled and educated with the majority of jobs requiring post-secondary education and long lead times to full competency when a new employee enters a role

Trades (42%) and engineering (22%) are the most dominant occupational groups within the electricity workforce, accounting for nearly two-thirds of the workers. Electrical and Electronic Engineers and Powerline Technicians are the largest occupations within the industry, each accounting for 11% of the total workforce. Labour demand is expected to increase for most engineering occupations. Electrical engineers, technologists and technicians, as well as telecommunications engineers, are expected to see the highest net increase in labour demand over the next ten years[3]

3 – ElectricityHR, Workforce in Motion Report

Market Impact at Milton Hydro

Trades & Technical Positions

With a normally nominal turnover rate, Milton Hydro has begun to experience an upward shift in its trades & technical group. Between 2018 and 2021 - 4 tradespeople left Milton Hydro's employ to work elsewhere

Milton Hydro has a fairly young trades workforce relative to the industry, with the average years of service at 13.9 and the average worker age of 40.1. Younger workers, with less invested in the Company and the Community, may be more prone to leave and seek work elsewhere, for a plethora of reasons

Milton Hydro's Line Person FTE headcount has dropped year-over-year from 11 in 2016 to 8 in 2021. It is currently seeking to attract 2 Line Persons to join in 2021, but is experiencing the challenges of a highly competitive market for fully qualified Line Persons

Market Impact at Milton Hydro

Leadership Skills & Capabilities

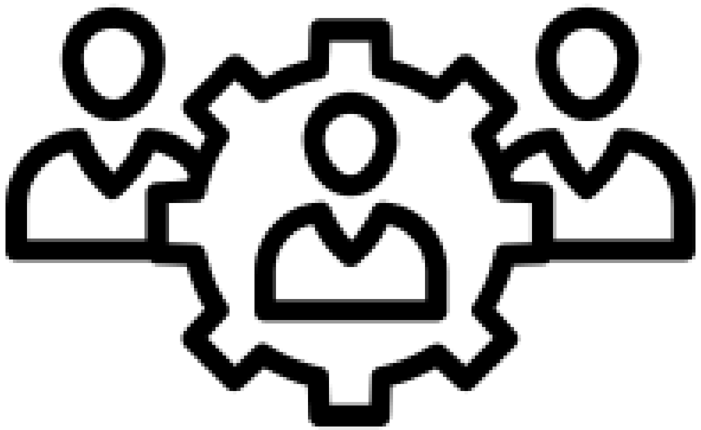
This new technology driven workforce will also require enhanced leadership capabilities. The anticipated changes over the next five years will have a similar impact on Milton Hydro's current and emerging leaders

Digital leadership is about empowering others to lead and creating self-organized teams that optimize the day-to-day operations. Leaders will need to deal with unprecedented changes and an unpredictable and challenging future due to the new digital era - driven by the advent of new technologies. In such a world, leadership will play a bigger role than ever. Leaders will have to create and show the way forward amid transitions, disruptions, chaos and ambiguity[4]

For Milton Hydro this means identifying the gap in capabilities of its leadership team, relative to what it needs now and what it will need in the future. It will be critical for Milton Hydro to define its Core Competencies, those expected behaviours and traits that will set the standard for all employees and drive a 'Whole of Organization' approach culture

4 – Developing Energy Digital Leaders – Deloitte 2020 Insight Report

Resource Optimization Drivers



1. Rapidly Growing Community & Customer Base
2. Responsive to and meeting Customers Expectations
3. Retirements & an Ageing Workforce
4. Continuous Improvement = Productivity & Efficiencies
5. Optimal # of Proficient Trades & Technical Workers Today and to Meet future Growth demands
6. Worker and Public Safety
7. Knowledge Management & Transfer

1. Rapid Community Growth

- 2016 Census from 2011-2016 states Milton's population increased by 30.5%
  - *Ontario 4.6%*
  - *National 5.0%*
  - *Top 10 fastest growing communities in Canada (6th overall)*
- Town of Milton's new official Plan dictates how the Community will look until the year 2031
  - *54% increase over its current population of 143,101 (2021) to 219,900 by 2031*
- Economic Development focused on:
  - *Technology Enabled & Multi-Dimensional Business Parks*
  - *Mobile Hubs and Smart Transit*
  - *All Inclusive and Interactive Residential & Small Commercial Communities*
  - *Education & Innovation Village*

1. Rapid Community Growth

Milton Hydro Impact

Since 2005 Milton Hydro's residential rates have increased 10.7% to 2019 (14 years), which is significantly below the rate of inflation

On the other hand, the cost of electricity has increased 90% over the same period, representing 59% of the total residential bill

Milton Hydro has done a good job keeping electricity rates low. In the 2020 Year Book Statistics Report, Milton Hydro's Controllable Cost per Customer is $256.59 compared to the average of all of its medium-sized comparators at $288.64

However, we feel this may not be sustainable considering the continued and rapid growth of the Town of Milton, with predictions of doubling by 2051[5] and other contributing factors outlined in the Review

5 – Town of Milton's Official Plan (on website)

1. Rapid Community Growth

Milton Hydro Impact

For the purposes of the Review we have been provided an estimated 1,000 increase in 'metered' customer growth from 2022 to 2027

Estimated at an on 'average' 2.19% increase year over year

To provide confirmation of continuing growth patterns, Milton Hydro commissioned a growth study, and confirmed the growth of 1,000 per year is expected to continue

2. Meeting Customer Expectations

A mix of Milton Hydro's Customer base participated in focus groups in 2021:

- *Residential, Commercial and Large Users*

Key feedback included:

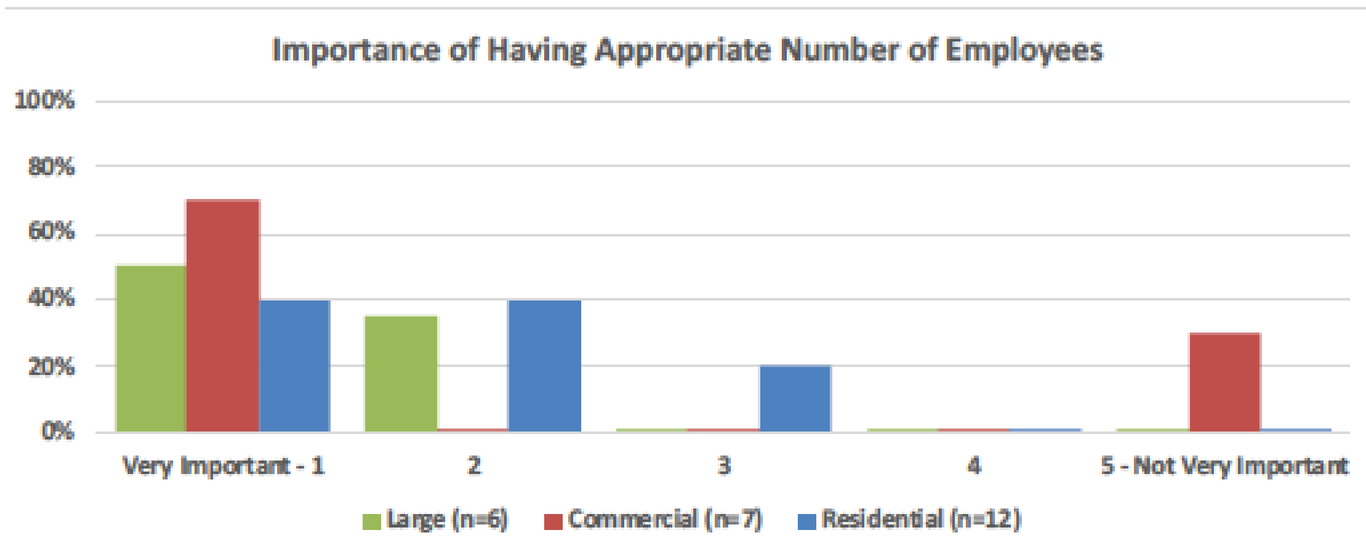
- *Customers, like Milton Hydro, are thinking about the future*
- *Customers are aware of the accelerated growth in the Community and the 'need to prepare for greater consumption' and have the workforce ready to accommodate the rapid growth*
- *Most believe Milton Hydro's rates over the past 5 years have been reasonable*
- *For many, being Future Ready means being prepared for extreme weather and using new technologies to address climate change*
- *Nearly all Customers think it is* ***VERY IMPORTANT*** *or* ***IMPORTANT*** *that Milton Hydro be 'appropriately staffed' and manage the system now and into the changing future*
- *Most considered Milton Hydro's OM&A proposed spending* ***VERY*** *or* ***SOMEWHAT*** *appropriate*

2. Meeting Customer Expectations

'Appropriately' Sized Workforce

Customers overwhelmingly (80% overall) rated it ***VERY IMPORTANT*** or ***IMPORTANT*** for Milton Hydro to manage the number of employees to effectively and efficiently' manage its assets and services

Customers highlighted the importance that '*new staff needs to be hired before others retire to assure effective knowledge transfer'*

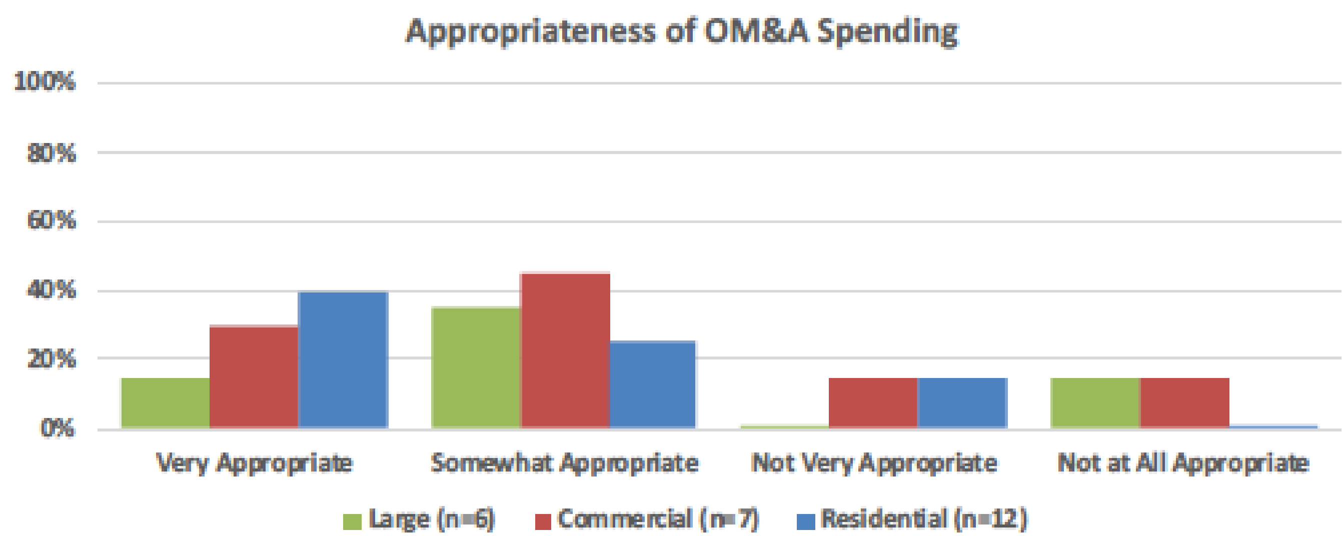


2. Meeting Customer Expectations

OM&A Spending on Staffing

Most (65%) Customers rated the proposed level of OM&A spending as *VERY* or *SOMEWHAT* appropriate

As much as 45% of Customers reiterated the theme that a growing Community needed more Milton Hydro staff to support its rapid growth – while 30% questioned *'how much rates would have to increase'*



2. Meeting Customer Expectations

Channels of Communication 'Need Improvement'

Some Customers (30%) said that they receive no communication from Milton Hydro

1/3rd of Customers suggested Milton Hydro's forms of Customer communication 'needed improvement'

Large Use Customer Quotes:

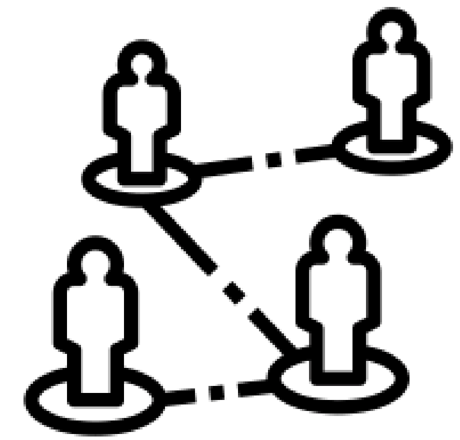
"I don't think anybody from Milton Hydro has ever called me just to review our usage and talk about what our future plans are or recap our business. Every other utility, I have a person in my contact list for. I don't have anybody in Milton Hydro."

"We used to have a relationship with the president of Milton Hydro...He used to come in here to explain some of the issues that we've had, but also talk about things that they were doing."

3. Employee Demographics

Retirements

	2021	2022	2023	2024	2025	2026	TOTALS
Trades & Technical (Union)							
Line Persons & Lead Hands	1						1
Meter Technicians		1					1
Engineering Techs. & Clerk							
SCADA & GIS							
Office Support Staff (Union)							
Accounting Clerks							
Billing Clerks							
CSR's						1	1
AMI & Material Handler							
Management/Professional Staff							
Executive	1						1
Directors				1			1
Managers			2				2
Supervisors	1		1				2
Non-Union Professionals	1					1	2
TOTALS	4	1	3	1	0	2	***11***



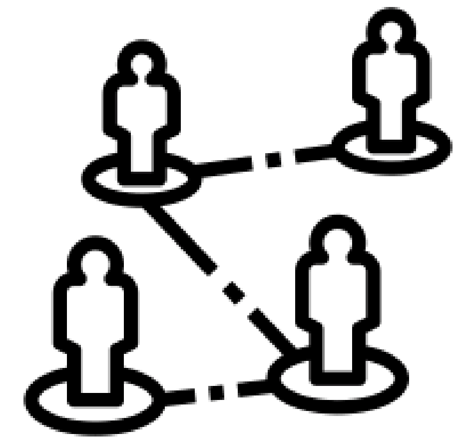
Milton Hydro trends slightly below the industry average of trades & technical and union employees who are eligible to retire in the next five years

Where Milton Hydro will be challenged is a substantive % of its management & professional are anticipated to leave in this time frame

Milton Hydro's historical trend from 2017 to 2021 indicates that 80% of those eligible do retire in the year they become eligible

3. Employee Demographics

Average Age & Years of Service



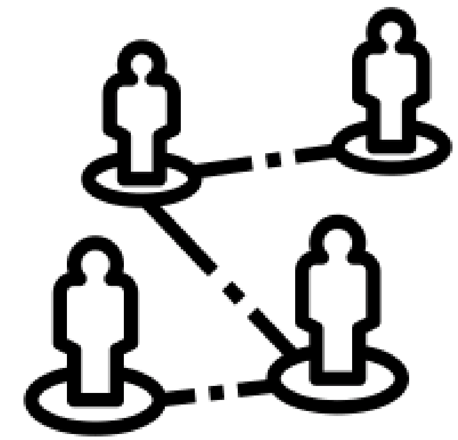
	Average Age in 2021	Average Yrs. of Service
Trades & Technical (Union)		
Line Person & Lead Hands	40.1	13.9
Meter Technicians	53.0	16.3
Engineering Tech. & Clerk	42.0	10.0
SCADA & GIS	38.0	9.7
Office Support Staff (Union)		
Accounting Clerks	41.0	10.7
Billing Clerks	35.3	5.0
CSR's	45.8	13.2
AMI & Material Handler	43.0	11.5
Management/Professional Staff		
Executive	48.0	0.8
Directors	58.0	5.0
Managers	55.5	15.5
Supervisors	51.6	18.0
Non-Union/Professionals	49.2	10.8

Milton Hydro's demographics indicate it has a fairly young trades & technical workforce, which is favourable trend

Aligned to eligibility to retire, Milton Hydro's Management Team's average age and years of service, fall within the industry norm according to Electricity HR's Workforce in Motion Study (2017-2022)

3. Employee Demographics

Turnover Rates



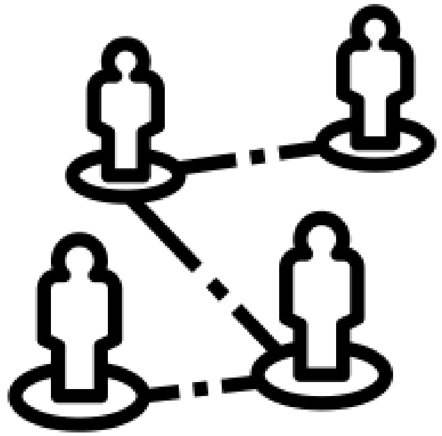
With a normally nominal historical turnover rate, Milton Hydro has begun to experience an upward shift in its trades & technical group. Between 2018 and 2021 - 4 tradespeople left Milton Hydro's employ to work elsewhere

The market supply for Line Persons is limited according to industry predictors. The specialized nature of the work, increasing demand due to increasing expenditures throughout the electricity sector, and the low level of employment opportunities for young workers in this field for many decades has reduced the robustness of the labour supply

Historical Turnover	2016	2017	2018	2019	2020	Year to Date 2021
Trades & Technical (U)			2	1		1
Office/Support (U)						
Management	1					
Non-Union/Professionals						

3. Employee Demographics

Turnover Rates

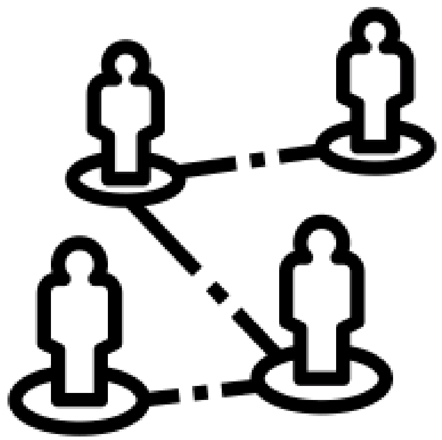


Turnover of employees within a budget year, either through retirement or attrition, impacts the business in many ways. From the time of an employee's departure to posting & advertising the position, interviewing and hiring new staff, it can take many months, and cross over from one budget year to the next

According to SHRM's Report – *Retaining Talent, A Guide to Analyzing & Managing Employee Turnover*: "Employee departures cost a company time, money and other resources. SHRM's research suggests that direct replacement costs can reach as high as 50%-60% of an employee's annual salary"

3. Employee Demographics

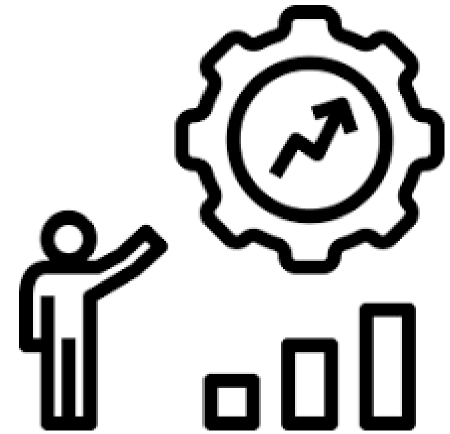
Turnover Rates



SHRM's research provides a breakdown of costs that impact the company when there is employee turnover such as:

Financial	HR staff time (exit interview, payroll administration, benefit changes)
	Manager's time (retention attempts, exit interview)
	Accrued paid time off (vacation, sick pay)
	Temporary coverage (overtime, contingent/contract employees)
Replacement Costs	Hiring inducements
	Hiring manager and unit/department employee time
	Orientation program time and materials
	HR staff induction costs (payroll, benefits enrollment)
Training Costs	Formal training (trainee and instruction time, materials, equipment)
	On-the-job training (supervisor and employee time)
	Productivity loss until proficiency reached
	Mentoring (mentor's time, travel)

4. Productivity & Efficiencies



Efficient Tool Time:

- *Materials in stock, stacked and ready for workers at the start of day*
- *Workers fully utilized every day and spending more time with tools in hand*

Efficient use of Equipment & Vehicles:

- *Full utilization of equipment*

Front-Line Supervisors Role:

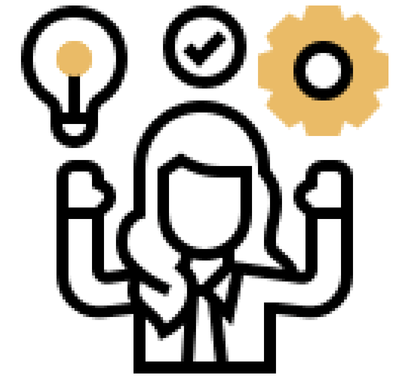
- *Capacity to do regular crew visits to monitor safe work practice and productivity*
- *Materials in stock and ready when workers are ready*
- *Effective utilization of in-house trades*

Right Utilization

- *Shift in Contract versus In-House trades work*
- *Efficiency gains in Outsourcing to balance increasing FTE headcount*

5. Sufficient & Proficient Workers

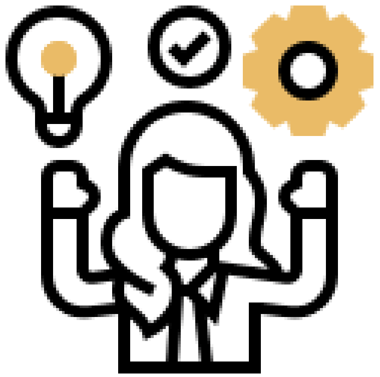
Years to Proficiency



Trades & Technical Positions	Years to Reach Proficiency	Comments
Line Person	5	May require longer for lead hand positions
Meter Technician	4.5	May be able to work on limited meters in first 2 years
Engineer/Design Technician	4	Requires college degree + hours
Engineer	4	Takes 4 years to quality for P. Eng.
GIS Technician	3	Requires college degree
Trades Supervisors	5-7	Requires leadership, right competencies & planning skills

Industry standards dictate the above # of years for each particular trades & technical role to be fully trained and proficient in their role

5. Sufficient & Proficient Workers



Advance Hiring Practices

Considering the long lead time for Lines Persons, Engineering and Metering Technicians to become fully proficient and qualified – it has been a long-standing practice in the industry to 'advance' hire and maintain an Apprentice pool, with continually rotating levels of proficiency – intended to be ready and able to succeed into a position once their training/experience is completed

Both within and outside of the trades, many organizations commit to starting the hiring process a few months in advance of a 'known' retirement or as soon as someone provides notice. This practice often provides the Company the ability to seamlessly transition roles, and puts less stress on the organization – as all employees feel the lose of a Supervisor, colleague or peer – where work and reports are temporarily re-assigned, until a replacement is hired

As part of the Resource Optimization exercise, we have made recommendations relative to advance hiring Milton Hydro should consider over the next five years

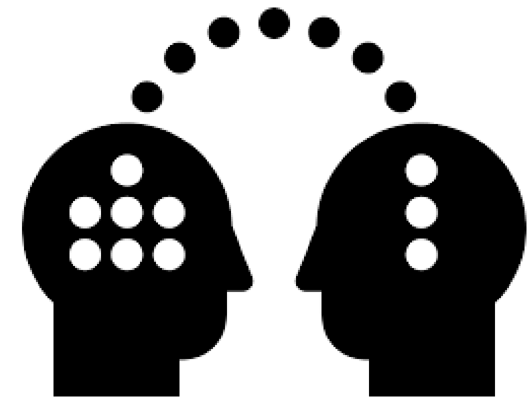
6. Worker & Public Safety

Every workplaces' Safety commitment should be focused on ensuring that everyone who works for the Company returns home safely and healthy at the end of the working day

In the electricity industry, that commitment requires a robust, proactive and collaborative approach to protecting employees and the public in general – working with electricity can be dangerous and workers need to be physically fit and mentally aware of potential risks, at all times

Public safety programs identify proactive initiatives to educate on safety, provide public service material and actively reach into the Community to promote public safety and raise the organizations brand awareness and reputation

7. Knowledge Transfer



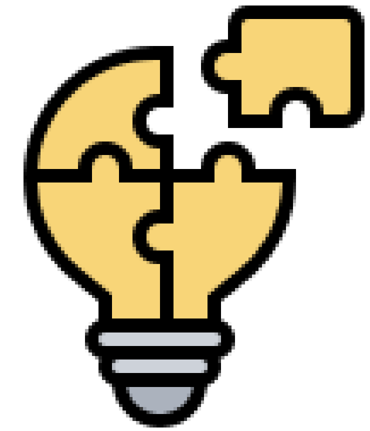
The changing landscape of the electricity industry poses significant human resource challenges. With retirements looming for a large cohort of employees from the baby boomer generation, utility leaders must develop knowledge transfer best practices to ensure that vital information and skills are retained within the industry

Thus, having a process in place to transfer skills from seasoned, departing employees to newcomers will help LDC's implement succession planning, onboard younger staff and provide ongoing training to prepare the workforce to adapt to change brought on by new technologies

A recent PwC Report recommends that utilities quickly adapt to technology, resource and demographic trends. It stresses the need to take an efficient approach to succession planning and knowledge transfer. The knowledge and commitment of the existing workforce must be harnessed as part of this. The same report points out that the way workforce changes are reshaping the risk profiles of energy utilities is posing challenges to their traditional control and compliance capabilities[5]

5 – PwC Powering Up the Electricity Resources of the Future Report 2020

WFP Key Assumptions



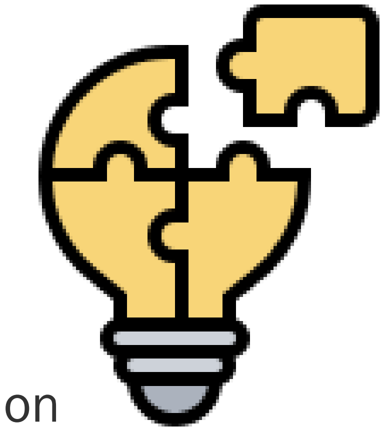
The single most critical element of WFP is the Assumptions used in developing the projections and outcomes. Wrong or incorrect Assumptions could:

- *Impact forecasting the right complement of manpower to meet the work demand*
- *Impact the integrity of the Right Sizing Plan*
- *Leave the business open to criticism and attack from interveners during a Rate Application*
- *Leave Milton Hydro unprepared in a rapidly changing demographic and technological environment*

The goal is to reduce the risk of effective execution associated with workforce capacity, capability and flexibility. The foundation for WFP is the business strategy; therefore, it needs to be owned by the business units

Business unit owners know their business needs, and understand what work needs to get done and how to do it. They understand their challenges related to productive versus non-productive employee time and the fluidity of their own workforces

WFP Key Assumptions



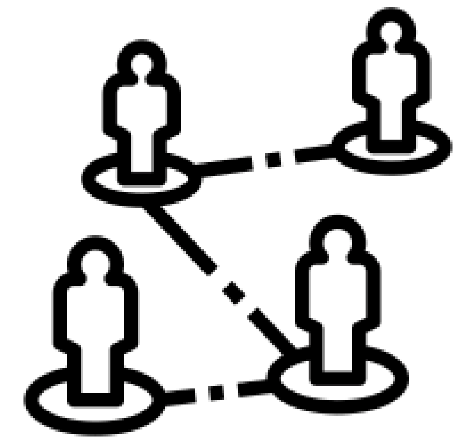
Milton Hydro's Key Assumptions

- 80% of eligible Employees will retire when they can receive their OMERS pension without penalty (historical trend from 2017 to 2021)
- Historic non-retirement attrition/turnover rates apply to the future
- Milton Hydro's Customer growth will increase by 1,000 on average every year from 2022 to 2027
- Optimal Capital spending will be split 60/40 between In-house (60%) and Contractors (40%)
- Advanced hires will benefit Milton Hydro's relative to:
  - *Capturing knowledge and critical know-how before it leaves the organization*
  - *Better assure trades proficiency at a qualified level to meet the reliability and responsiveness obligations to its Customers and Community*
- Process improvement & automation should help drive productivity & efficiencies and empower & enable employees (end-users)

Review Outcomes & Considerations

Employee Demographics

Milton Hydro's Opportunities & Challenges



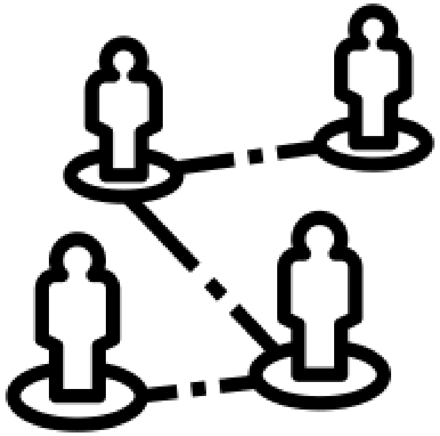
Milton Hydro's current structure, in our opinion, does not provide sufficient internal band-width nor has it, over the past many years, proactively invested in succession planning to sufficiently fill this void

Minimal investing in sufficient hiring, onboarding and developing new hires, has the potential to impact Milton Hydro's ability to function optimally. Increasingly, the supply of trained Power Line graduates into the electricity sector will be a challenge.

Milton Hydro is poised to utilize a multi-faceted approach to allow for flexibility to 'right size' its workforce and management team over the next five years, and allocate sufficient funds to ensure its new hires are properly onboarded, trained and developed to mitigate potential risks associated with working in a high-risk environment and vying for talent in a highly competitive market

Employee Demographics

Milton Hydro's Opportunities & Challenges



It is important to note that with turnover and retirements also come opportunities. As individuals leave, Milton Hydro can replace those workers with different and/or new skillsets or positions that would add greater value to the industry's 'new' emerging business model

Some occupations may no longer be needed as a result of technological change. To maintain organizational knowledge and experience, Milton Hydro will need to determine whether *reskilling workers* to new roles is possible and determine the right recruitment strategies

A number of occupations including Supervisors, tradespeople and engineers will be impacted. Current employees may find that they lack the skills needed to perform new digital tasks

To prevent productivity loss and benefit from innovative opportunities – proactive recruitment strategies will identify the opportunity of *upskilling workers* to improve their digital proficiency to better perform their work, and to ensure the retention and transfer of critical knowledge and experience

Responsive to Customer Expectations

The Resource Optimization Review has imbedded what Milton Hydro's Customers told it, through its Customer Engagement exercise in 2021

Areas of focus for Customers:

1. That Milton Hydro is able to adapt to changes in society and the electricity sector. That it will be able to meet the increasing demand for electricity and respond to the challenges of climate change, including extreme weather events
2. Nearly all Customers felt it 'appropriate' that Milton Hydro be adequately staffed now and into the future to meet the changing demands of the sector and most importantly, be able to adequately respond during severe weather conditions
3. Improve interactions and enhance communication channels with Customers, keeping them informed of planned work, outages, and, response & restoration challenges

Right Sizing

Trades & Technical Workforce

Milton Hydro has, over the past few years, reduced its Line Person staff through outsourcing, and is currently operating with 8 fully qualified lines trades

The Company is also considering shifting its Ratio of In-house trades to Contracting Out from an estimated *20%:80%* to approximately *60%:40%*

The rationale for shifting the Ratio is still evolving as the Company works through its planning process. As part of the Review we have provided the Director Engineering's Optimal Trades & Technical workforce, for the Company to consider during its continued deliberations

In determining the 'right size' for its Trades & Technical workforce we sought input from five of Milton Hydro's medium and large-sized industry peers

The tables on the following page provides the aggregate ratios of the group, and ranges for each Ratio and how Milton Hydro's workforce compares

Right Sizing

Trades & Technical Workforce

AGGREGATE OF 5 LDC's

Line Person	Supervisor	Ratio
		5:1
Range	Range	Range
11 to 38	2 to 10	2:1 to 5.5:1

Apprentice	Line Person	Ratio
		1:3.25
Range	Range	Range
4 to 13	13 to 38	1:2 to 1:4

Eng. Tech	Supervisor	Ratio
		4:1
Range	Range	Range
5 to 13	1 to 4	2:1 to 5:1

MILTON HYDRO 2021

Line Person	Supervisor	Ratio
10	2	5:1

Apprentice	Line Person	Ratio
0	10	0

Eng. Techs	Supervisor	Ratio
2	1	2:1

Milton Hydro is in line with its industry peers relative to Line Person to Supervisor ratio, and lower in its Engineering Technicians to Supervisory ratio

Milton Hydro is the only LDC that does not currently maintain Apprentices to feed into its Line Person pool

Advance Hiring of Apprentices

Considering the upward trend in trades attrition, Milton Hydro's Resource Optimization Review includes increasing its FTE headcount, to accommodate Apprentices that require up to five years of training to become proficient and qualified to safely operate within the role

A limiting factor of adding new Apprentices to the workforce is that there is a limit to the number of Apprentices that can be effectively and safely integrated into the operations, considering the required training and mentoring during the five years. The common ratio in the industry (as per the Peer Study) is 1 Apprentice to every 3 Line Persons.

However, considering the 'average age' of its current trades group Milton Hydro has time to pace out its 'advance hires' over the next 10 years, and the Review recommends bringing1 or 2 Apprentices on board in the next five years, aligned with a planned increase in trades and frontline Supervisors

Right Utilization

In-House to 3rd Party Contracting Out

AGGREGATE OF 5 LDC's

In-House	Contracting Out
73%	27%
Range	
60/40 to 90/10	

MILTON HYDRO 2021

In-House	Contracting Out
20%	80%

MILTON HYDRO 2027

In-House	Contracting Out
60%	40%

Milton Hydro's ratio of in-house to contractors (Capital and/or Operating) is almost the opposite of the LDC's utilized as comparators

The Director Engineering has proposed a shift in the ratio, and plans to transition the shift over time. In determining the 'Optimal' trades structure we have taken Milton Hydro's ratio's against the industry comparators and used its Director's recommended changes

Right Utilization

In-House to 3rd Party Contracting Out

Typically in medium to large-sized LDC's, a large percentage of the planning, work and operating on the distribution plant is performed by internal labour. The services of third-party power line contractors are normally used to assist with the construction of large capital projects and work the utility is unable to fill due to resource restrictions

Often, the civil construction work and tree trimming are performed by contractors. Some technical planning and design may also be performed by engineering consulting firms. Maintenance on the distribution plant is predominantly performed by internal staff

To meet the asset management needs of the distribution plant LDC's rely on a highly skilled core of technical and trades staff to perform the majority of the work. Services of contractors are used for work that is not electrical utility specific (civil construction and tree trimming), as well as to assist in the managing of varying seasonal work loads and year to year for core electrical utility work

Resource utilization and work schedules are optimized through the use of a mix of internal staff and third-party service providers

Right Utilization

Improved Tool Time

Tool time in the electricity trades has always been difficult to capture, with any certainty. Working on the distribution system is only part of what a tradesmen does in any given day

The hours spent on non-tool time activities includes: safety meetings, tailboards, loading equipment, vehicle inspections, set up and break down time, and rest time and lunch periods

The above activities can take hours out a day's work being performed with tools in hand, on the job

Although Milton Hydro can find some efficiencies in these activities, most are mandated safety requirements

Where Milton Hydro indicates it can focus improving efficiency is in areas that cause delay, repetitive tasks and full daily utilization of workers, plus improving inventory and materials availability at job sites

Right Utilization
Improved Resource Capacity

Adding ***capacity and capability to free up Supervisor time*** to:

- *Conduct crew visits: monitor efficient use of time and tools*
- *Supervisors have a role in managing inventory and materials for each job, reducing the need for workers to come back to the yard for materials throughout the day*
- *Mentoring trades on safe work practices, keeping them focused with mind on task*
- *Monitoring rest and lunch breaks are taken as prescribed within the CA*
- *Better management of overtime, on call and shift work*
- *Manage employee performance and development*

Utilization of ergonomic and automated tools:

- *Safer, less physical stress and keeps workers working and on the job*
- *Assists in concerns of an ageing workforce as time goes on*
- *Automation frees up time for workers to be on the job with tools in hand*

Right Utilization

Improved Resource Capacity

Adding ***expertise and capacity to procurement and inventory controls*** to:

- *Work with vendors for 'just in time' delivery of equipment/materials to job sites*
- *Effective vendor relationship management*
- *Strategic sourcing and recommendations for ergonomic and automated equipment & tools*
- *Ensure supply chain aligns to projects and inventory demands*
- *Monitor and replace equipment reaching end-of-life (safety & reliability hazard)*

Right Utilization

Improve Efficiency & Decrease Costs by Outsourcing Work

Milton Hydro's Resource Optimization Review focused on roles, capabilities and how best the Company can utilize its workforce, now and into the future

Considering the Review recommends a transitional year-over-year increase in headcount, it is recommended that Milton Hydro consider where it can offset increased headcount costs, gain efficiencies and improve worker productivity

It is our understanding Milton Hydro is currently considering such options. We would suggest it could include:

MV90 data collection & processing	Meter Reading
Billing Settlement & AMI functionality	Call Centre
Engineering & Design Services	IT Services

There is a multitude of evidence on the pros and cons of outsourcing in the industry, and many LDC's currently outsource a variety of work and services

Milton Hydro has an opportunity, through its industry contacts/network, to research & identify which LDC's have been successful and why, and which less so, and what have they learned?

Right Skilling

Milton Hydro Competencies & Capabilities

In discussions with the SMT there is evidence that the level of leadership maturity, is limited in some areas

The SMT have a higher-level of maturity, and organizational awareness of current and potential barriers to achieving Milton Hydro's Strategy 2.0

Bench strength below SMT is narrow, due primarily to an overly lean structure which has resulted in capability and capacity challenges

In the current structure, and as a result of the above stated challenges, the CEO and CFO are spending time and effort addressing issues and making decisions that should/can be made at a more junior level in the organization

Right Skilling

Milton Hydro Competency & Capabilities

The SMT provided areas where business processes and standards, could be tightened and in some cases, better managed

The CEO and CFO provided candid insight into potential operational areas they have uncovered and are working to resolve. Considering the short tenure of the CEO, CFO and Director Regulatory – they have, in our opinion, delved deep into the organization, sufficiently interacted with employees at all levels and were able to clearly articulate the current state and suggestions for improvement

Although still a work in progress by the CEO & CFO in determining the root cause of the lack of attention to some processes and business requirements, these indicate there is evidence of a combination of lack of expertise/skills and insufficient levels of management to act as a counter check and balance on processes, authority and managing performance expectations

Right Skilling

Knowledge Transfer Opportunities

With specialized skills powering the workforce and the continued risk of losing depth in the utility's corporate knowledge base, Milton Hydro may wish to consider as part of its long-term resource planning - engaging older workers and retirees in ensuring operational capacity and continuity Milton Hydro could consider putting formal guidelines in place to:

- Delay retirements, where appropriate, to maintain a culture that values experience and supports knowledge transfer opportunities
- Engage employees transitioning into retirement by leveraging hiring overlaps for unique positions to ensure that knowledge, skills, and corporate memory are passed onto the next generation and by integrating pre-retirement older workers into mentoring programs to enhance knowledge transfer

Without the implementation of such knowledge-transfer mechanisms, Milton Hydro, similar to the industry, is at risk of significant corporate memory loss, declines in productivity, compromised business continuity, and losses of intellectual capital

Process Improvement

- Process improvement involves the business practice of identifying, analyzing and improving existing business processes to optimize performance, meet best practice standards and/or simply improve quality and the user experience for customers and employees
- Institutionalizing a Six Sigma discipline approach builds a customer-centric and efficiency mindset, with all employees focused on value-add activities and continuous improvement opportunities
- Milton Hydro recognizes that productivity & efficiency improvements are a priority to: offset and minimize FTE increases against its rising customer growth; optimize business processes & continuous improvement initiatives; and maintain reasonable impacts on customer rates

Internal Bench-Strength

Milton Hydro operates a very lean organization, whose structure has only 2 Executives and 2 Directors (senior level positions). Compared to its medium-sized LDC peer group, Milton Hydro's Customer to Employee Ratio (808:1) is far above its comparators

In fact, out of all LDC's (small, medium and large) Milton Hydro has the 5th 'highest' ratio of Customers served to Employees[6]

Although this approach can sometimes provide quicker decision-making, for Milton Hydro it affords no bandwidth between Executive and Supervisor positions. This results in more hands-on effort at the senior level, less career development for Managers and Supervisors, and succession planning constraints

Further, the results of the Organization Structure Review convey Milton Hydro's management structure is too lean for the size and scope of the business, which could result in insufficient layers of accountability, decision-authority, business acumen and leadership capabilities

6 – 2020 Year Book Statistical Data Analysis

Internal Bench-Strength

Milton Hydro	Waterloo North	NPEI	Energy +	Oshawa PUC
41,221 Customers	58,438 Customers	56,973 Customers	67,303 Customers	59,486 Customers
51 Employees	119 Employees	121 Employees	121 Employees	76 Employees
Ratio 808:1	42% more Customers 133% more Employees Ratio 491:1	38% more Customers 137% more Employees Ratio 470:1	63% more Customers 137% more Employees Ratio 556:1	44% more Customers 73% more Employees Ratio 782:1
• CEO • CFO	• CEO • VP Finance/CFO • VP IT • VP Operations • VP Eng., Stations & Metering	• CEO • SVP Asset Management • VP IT/Billing • SVP Finance • VP HR • VP Communication & Marketing	• CEO • VP HR • CFO • VP Operations • VP Engineering • VP IT Services • VP Customer Service	• CEO • VP Eng./Ops • VP Bus. Dev. • VP Finance

Medium-Sized LDC's (2020 Stats)

Internal Bench Strength

Milton Hydro Capability & Expertise

Results of Resource Optimization Review interviews:

- Appropriate & timely decisions are being executed
  - *However, not at the operational level where they should be*
- Lack of management bench strength between Supervisor & SMT sends everything to the top
  - *Acceptable practice in the past that all decisions are made at the highest level*
  - *Top-down organizational style that centralizes decision-making responsibility*
  - *Insufficient accountability and/or staff operating at a more junior level*
- Lack of sufficient focus on processes, innovation and continuous improvement initiatives
  - *Operating a lean organization results in insufficient capacity to dedicate time and effort to anything outside of need-to-do expectations*

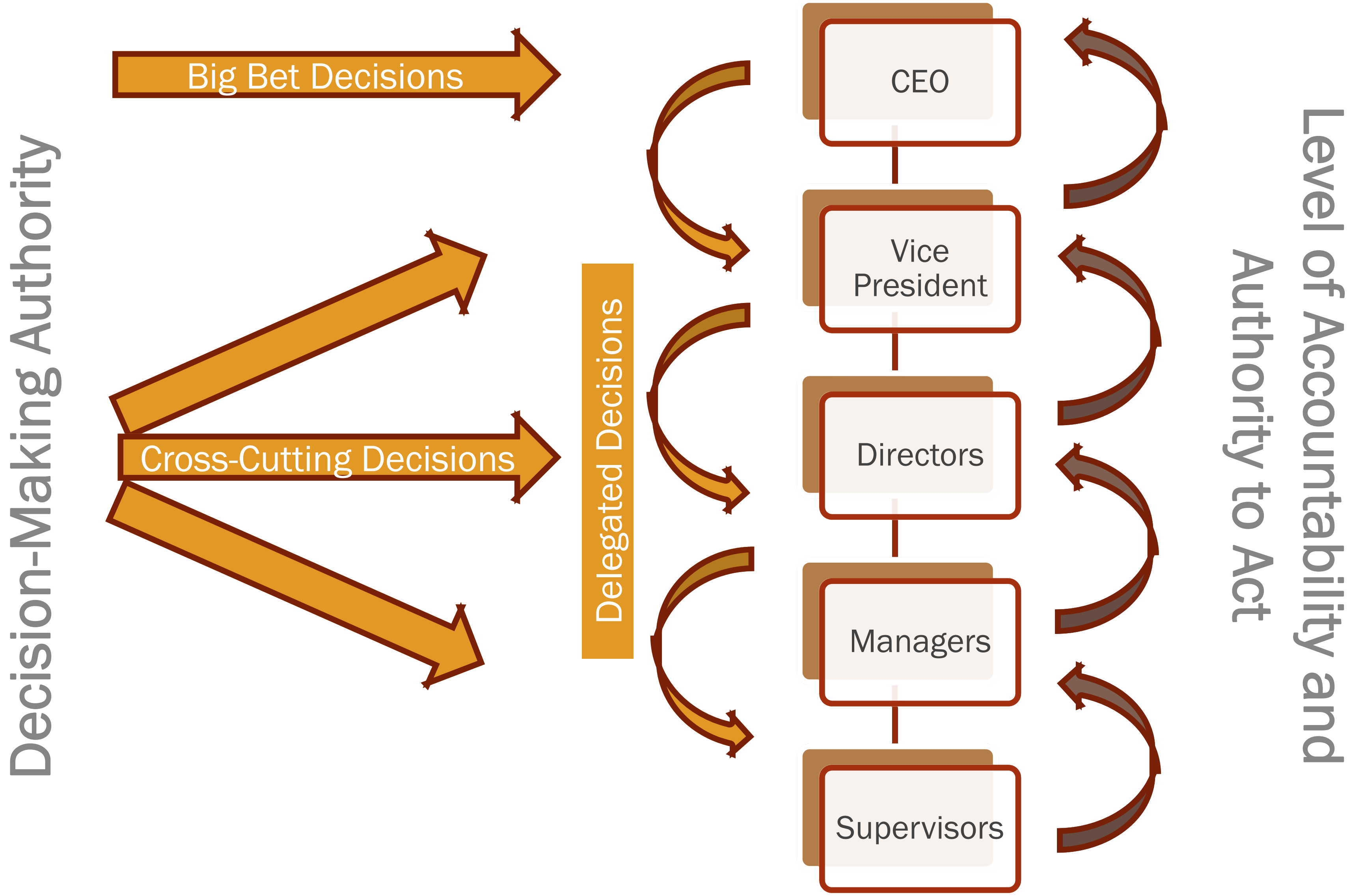
Internal Bench Strength

Milton Hydro Capability & Expertise

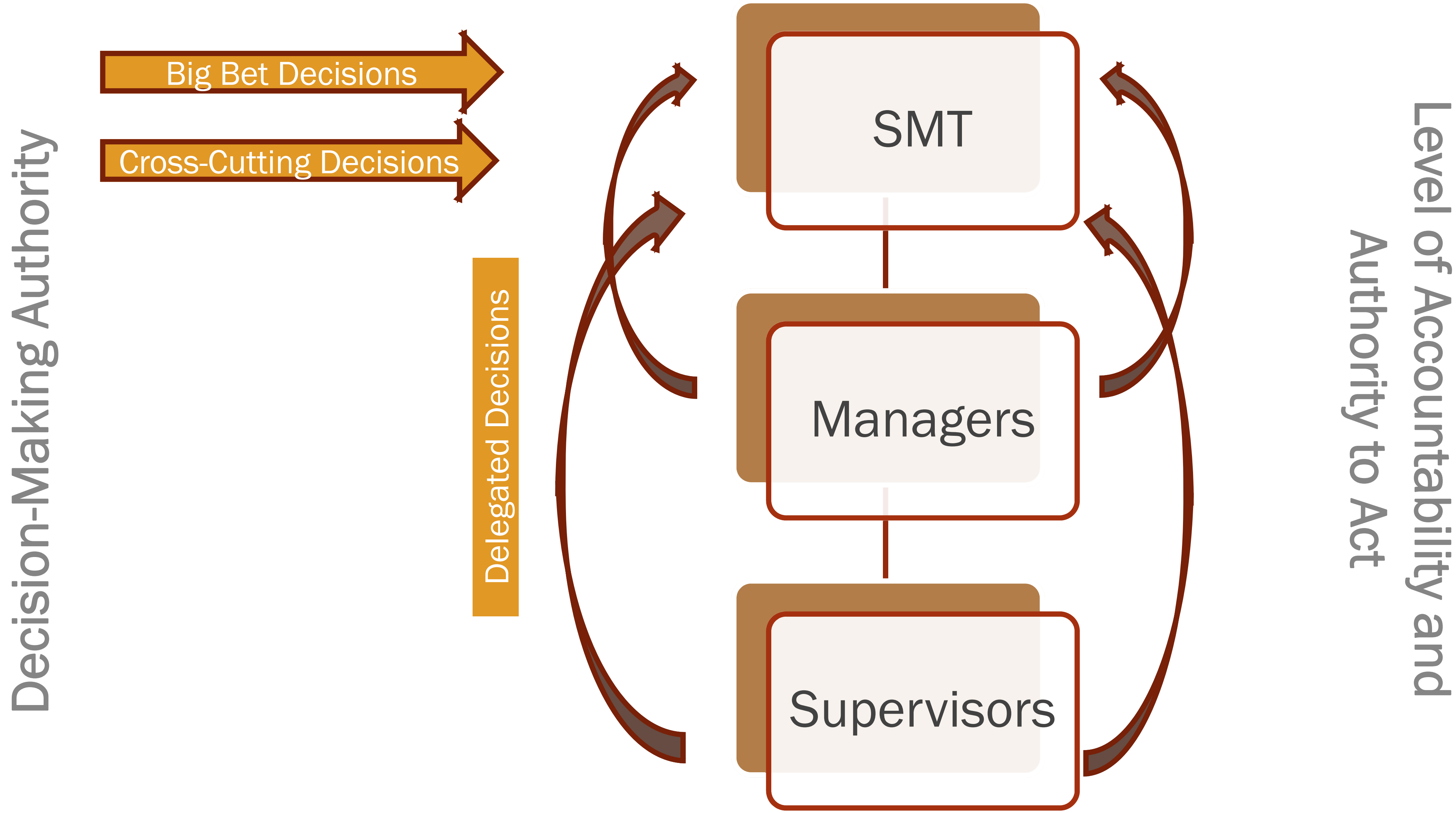
Results of Resource Optimization Review interviews:

- Insufficient layers of authority
  - *Can result in the same individual who enters/inputs information also reviews and/or approves*
  - *Appropriate checks and balances & cross-checking – ensuring adequate and timely review of financial and regulatory documents and filing allowing multiple reviews and touchpoints*
- Holding people accountable
  - *More difficult without clear roles & responsibilities and appropriate layers of reporting and oversight*
- Enhance Health & Safety Program
  - *Develop a proactive leading indicator program vs. reactionary*
  - *Focus on Internal Responsibility System (IRS) where every employees takes accountability for their own safety and has concern for co-workers*

Traditional Hierarchy Structure



Milton Hydro Hierarchy Structure



Optimal ‘*Workforce Planning*’ Structure

(Trades & Technical Workforce)

Optimal Trades/Technical Workforce

Assumes a Shift to 60% In-House vs. 40% Contractor Line Work

Trades & Technical Positions *	2027 Optimal #'s	2027 Minimal #'s	2021 Budgeted	2022	2023	2024	2025	2026	2027
Line Persons	**12**	11	7	9	9	10	10	11	**12**
Lead Hands (LP)	**4**	3	3	3	3	4	4	4	**4**
Metering	**4**	3	3	3	3	3	4	4	**4**
Engineering & Design	**4**	3	2	2	3	3	3	4	**4**
SCADA/GIS	**4**	3	3	3	3	3	4	4	**4**
Apprentices	**2**	2	0	1	1	2	2	2	**2**
Trades Supervisor	**3**	2	2	2	2	3	3	3	**3**
+ FTE'S (13 over 5 years)				3	1	4	2	2	1
Ratio's									
Line Person to Supervisor	5:1	7:1	5:1						
Engineering Tech. to Supervisor	2:1	1.5:1	2:1						

* As provided by the Director Engineering

Optimal Trades/Technical Workforce

Milton Hydro has made assumptions in determining its ‘Optimal’ and ‘Minimal’ staffing levels for the next five years based on:

- *A shift in In-House vs. Contractor work*
- *A need to hire Apprentices, to proactively ensure sufficient proficiency of Line Persons to maintain a safe & reliable distribution system*
- *Supporting its business case, currently under review, to institute a 24/7 Control Room (FTE’s unknown to date)*
- *Its ability to adequately manage its workforce and Apprentices*
- *The LDC peer review of medium and large-sized utility worker ratios*

The next slides provides proposed justification and rationale for increasing the trades & technical workforce and front line management over the next five years

Optimal Trades/Technical Workforce

Rationale and Justification

1. Experts are predicting continued and ***more severe extreme weather***. Milton Hydro Customers share this concern and were clear they support the Company being sufficiently staffed to deal with severe weather conditions, quicker restoration time and improved predictive reliability to mitigate outages during storms:
   - *Adding trades decreases Milton Hydro's current reliability on outside contractors performing restoration work*
   - *Milton Hydro pays premium labour costs for work outside normal working hours & emergency work, can be done less costly with in-house staff*
   - *Milton Hydro is one of many of the contractor clients, and restoration activity and manpower is spread between those clients*
   - *Manning its own 24/7 Control Room assures Milton Hydro customers are restored as a priority*
2. With additional Supervisory and Supply Chain capacity Milton Hydro has the opportunity to provide ***better Utilization of trades & inventory***, reduce costs and improve efficiencies

Optimal Trades/Technical Workforce

Rationale and Justification

3. Milton Hydro has the opportunity to pursue initiatives to ***off-set increases in FTE's*** with potential outsourcing opportunities (Slide 47)
4. Concern of ***losing qualified trades staff***. With the number of Line Persons decreasing year-over-year, work that is normally always performed by in-house trades is being done by 3rd party contractors, which has led to:
   - *Employees have voiced their desire and disappointment they are not able to utilize their skills to their potential*
   - *Discontentment can impact employee engagement, but in the electricity sector – can cause distraction and complacency on the job*
   - *Workers who feel unvalued, are more likely to seek employment elsewhere in the sector*

Optimal Trades/Technical Workforce

Rationale and Justification

Following each retirement or attrition move, Milton Hydro is faced with a loss of knowledge and experience and the need to train and develop workers who are new hires or promoted internally

Regardless of whether Milton Hydro shifts its In-house to Contract work, or at what pace over the next few years – there may be a need to increase the number of Line Persons, Lead Hands, Apprentices and add increased management of front line Supervisors as per the rationale and justification provided

Optimal ‘*Organizational*’ Structure

(Non-Trades)

Optimal Structure

The CEO and CFO recognize there are challenges in expecting the right level of skills and expertise from some individual’s in current roles

This is not necessarily that the individual’s do not have the capability, but that they have either not been given the authority/training in the past and/or due to the lean structure, they do not have the time or resources to operate at the required level

The Review puts forward recommendations on increasing headcount to fill the gaps identified in the Review - attempting to ‘*Right Size*’ and ‘*Right Skill*’ the organization to be more effective, efficient and responsive to Customers expectations

LEGEND

Role Changes | New Role

Additional FTE's & Change in Accountability

Role	Description
Regulatory Analyst (+1)	Currently a Financial Analyst, shared w/finance. Regulatory requires a dedicated and focused Regulatory Analyst to assist the Director Regulatory in monitoring compliance, meeting legislative requirements, COS Application process, etc.
Client Services Financial Analyst (Role Change)	With adding a dedicated Regulatory Analyst, the current Finance Analyst will be fully dedicated to support the finance department, adding capacity and capability. The role will change and have a focus on supporting internal clients through the budget & forecasting processes and to help build this acumen internally
Finance/Payroll Specialist (Role Change)	Payroll is currently a primarily manual process. Aligned to HRIS implementation, add Payroll Accountability to current Finance Specialist
Manager Finance (+1)	Provides separation of duties from Controller, works to set up vendors and authorizes payments. Manages the work and resources of the finance team to provide accurate financial information to various stakeholders. Provides guidance, coaching and feedback to staff to develop and achieve individual and departmental goals. Analyzes, reviews and validates financial information ensuring accurate and timely monthly financial statements, reporting and filings

LEGEND

Role Change	New Role

Additional FTE's & Change in Accountability

Client Services Financial Analyst (+1)	Internal client centric function, works with operational partners on setting budgets, quarterly forecasting, managing to budget, allocations and financial reporting. Takes a lead role in the documentation of workflow procedures, improving business operations via workflow re-engineering and the implementation of new business applications to support organizational needs
Manager Operations (+1)	Line Supervisors report into this position. Organizes & priorities work activities for in-house and 3rd party contractors. Manages resources to ensure work scope is achieved and aligned with budgets. Ensures the delivery of services is provided within the framework of approved policies, applicable standards and regulations. Develops and monitors operating and capital work assignments and ensure projects are completed as planned. Assists in the development of operating and capital budgets, monitors spending and redirect work as required. Seek opportunities for cost reductions and continuous improvement efficiencies. Capacity to provide support to allow senior operations role to be more strategic and people/performance focused

LEGEND

Role Change	New Role

Additional FTE's & Change in Accountability

Role	Description
Manager SCM (+1)	Enhances internal controls and adds strategic focus to Milton Hydro's full Supply Chain processes. Procures goods and services consistent with requirements, ensuring optimal pricing, quality and timeliness are achieved. Develops bid documents and manages the RFP/Tender process through to selection. Creates and analyzes purchasing and inventory reports and take appropriate action when required. Negotiates contract terms with suppliers for goods and services ensuring best value for the organization. Assists in the development of operating and capital budgets as an active business partner
Supervisor Facilities/Fleet (Role Change)	Change from Procurement & Facilities Supervisor. Provides daily direction to maintenance, warehouse and mechanical staff/vendors to ensure work is completed efficiently and safely. Communicates with suppliers regarding parts or inventory requirements. Ensures inventory levels are maintained as appropriate to meet operational requirements. Provides direction to outside contractors to ensure maintenance programs are maintained and work is completed according to Milton Hydro and safety standards

LEGEND

Role Change | New Role

Additional FTE's & Change in Accountability

Director IT & Client Services (+1)

No current capability to focus on IT Strategy and Enterprise Solutions focused on enabling and empowering employees (end-users). Position will seek out and mitigate potential compliance and control concerns. Responsibilities include overseeing the infrastructure of technical operations, managing the IT staff, keeping abreast of best practice, and supporting the organization to: achieve business goals; minimize cyber and security risks; increase end-user satisfaction, and automate for efficiency of operations and systems

IT Infrastructure & Security Specialist (+1)

Responsible for the daily management and implementation of a secure, reliable network and systems infrastructure. Enhanced focus on risk mitigation in Cyber Security, Business Continuity and Disaster Recovery planning. Responsible for the configuration and management of network switches, routers, firewalls, intrusion detection and protection devices, antispam appliances, filtering devices, and Internet caching appliances, etc.

LEGEND

Role Change	New Role

Additional FTE's & Change in Accountability

Manager H&S (+1)	Currently a contract position. Focus on enhancing the current safety program and processes. Allows more time spent on crew visits/safety inspections, and mentoring trades & technical staff. A dedicated professional with capacity to enhance: the current Internal Responsibility System; champion and promote a leading indicator safety program; focus on proactive/predictive vs. reactive safety initiatives; maintain compliance; and, introduce a formal OH&SM system
Billing Clerk (+1) CSR (+1)	Addition of one billing clerk and one CSR over the next five years, to respond to the increase in Customer growth and increase in Customer expectations as interactions with Customer evolve
Process Improvement Officer (+1)	Focus on continuous improvement, productivity improvements, mapping processes, supports substantive projects, ensures business optimization and standards/policy compliance. Brings new skill to organization to support business unit leaders and the senior team (project management, change management, Six Sigma Lean skills, etc.)

OPTIMAL STRUCTURE
5-YEAR TRANSITION PLAN
CONSIDERATIONS

5-Year Transition Plan

Pace of Transition

Most change efforts fail because they are not given the sustained attention, commitment, and often the time to take hold and be accepted

The most substantive determination in pacing, focused on improving Milton Hydro's Internal Control and Safety risks. As well as hiring senior level strategic capabilities and expertise

A second major determination in pacing is centred on replacement hiring and new hires to immediately improve management leadership skills and capabilities

If you go too slow…..		If you go too fast…..
You lose momentum – the process doesn't seem important enough and gets lost in the day-to-day business activities		*You leave people behind – they don't understand why the change is necessary & happening and they resist it*
Change feels like a Band-Aid being pulled off slowly – employees just want to know what is happening and get it over with		*Too many unanswered questions are left to the implementation stage – people waste energy sorting out internal confusion*
The energy sector environment will change before you have realized the benefits of the re-design		*You defocus the organization from day-to-day work and your fundamental business suffers*
You could lose talented people due to no change in leadership or demonstrated commitment to make changes		*You may not have sufficient time to assess current capabilities/competencies & place the wrong people in the wrong positions*

5-Year Transition Plan

Sequencing Considerations

Implementation is not a ‘one-time’ event. It is an iterative process that involves a series of changes that occur over time. Bear in mind that some things must occur before others and that when bringing in VP roles, the individuals should have input into what their structure needs to look like now and over time

There may be changes you want to make to the design, as you get feedback from new leaders and reality intrudes year over year

Avoid making hasty changes without considering overall implications and how it can impact the efficiency of the reporting structure

Position	2021	2022	2023	2024	2025	2026	2027	Rationale
Manager Health & Safety		1						Dedicated safety professional to enhance safety program, and add capacity to support employees and Supervisors
Line Persons		2		1		1	1	Rapid Customer/Community growth & proposal to shift inhouse vs contractor work to 60%/40% from 20%/80%
Lead Hands				1				
Apprentices		1		1				Need to advance hire allowing time to reach proficiency w/shortage of skilled Line Persons
Metering Technicians					1			Rapid Customer/Community Growth
Engineering & Design Techs.		1				1		Rapid Customer/Community growth & proposal to shift inhouse vs contractor work to 60%/40% from 20%/80%
GIS & SCADA Technicians					1			
Supervisor Operations				1				
Regulatory Analyst	1							Now only part time, need to have a dedicated Analyst well in advance of upcoming COS process
Manager Operations		1						Provides support to VP Distribution Services and manages resources to ensure work scope is achieved and aligned with budgets. Allows VP to be more strategic, customer centric and continuous improvement focused

Position	2021	2022	2023	2024	2025	2026	2027	Rationale
Director IT & Client Services		1						Need to develop IT Strategy & Enterprise System Roadmap for next five year and beyond
Manager SCM	1							Lack of capacity in the role, and adds strategic focus to Milton Hydro's full Supply Chain processes
Supervisor Facilities & Stores	C							**Change in role**: current incumbent considered to move into Manager role, hire dedicated individual to maintain all facilities & assets and manage inventory (improved tool time for trades)
IT Infrastructure & Security Specialist			1					Responsible for the daily management and implementation of a secure, reliable network and systems infrastructure. Enhanced focus on risk mitigation in Cyber Security, Business Continuity and Disaster Recovery planning
Client Services Financial Analyst (Finance Business Partner)		1						Internal client centric function, works with operational partners on setting budgets, quarterly forecasting, managing to budget, allocations and financial reporting. Supports the development of leadership financial acumen
Billing Clerk						1		Rapid Customer/Community Growth
Customer Service Rep.						1		Rapid Customer/Community Growth

Position	2021	2022	2023	2024	2025	2026	2027	Rationale
Manager Finance					1			Provides separation of duties from Controller, works to set up vendors and authorizes payments. Manages the work and resources of the finance team to provide accurate financial information to various stakeholders. Re-assess to determine need once other support structures/roles in place
Process Improvement Officer	1							Focus on continuous improvement, productivity improvements, mapping processes, supports substantive projects, ensures business optimization and standards/policy compliance. Brings new skill to organization to support business unit leaders and the senior team (project management, change management, Six Sigma Lean skills, etc.)

Non-Financial Impact of Changes

Change in LDC Comparisons

2020 Actual	2027 Projected	Avg. Medium-Sized LDC (2020)
41,221 Customers	48,100 Customers	42,450 Customers
51 Employees	75 Employees	79 Employees
Ratio 808:1	Ratio 641:1	Ratio 537:1

Assumes 1,000 Customers Annually

EXHIBIT 4

ATTACHMENT 4-4

2020 RSM ACTUARIAL REPORT

MILTON HYDRO DISTRIBUTION INC.

REPORT ON THE ACTUARIAL VALUATION OF POST-RETIREMENT NON-PENSION BENEFITS

AS AT DECEMBER 31, 2020

FINAL – February 26, 2021

THE POWER OF BEING UNDERSTOOD
AUDIT | TAX | CONSULTING

RSM

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EXECUTIVE SUMMARY

Purpose

RSM Canada Consulting LP was engaged by Milton Hydro Distribution Inc. (the "Corporation") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2020. The nature of these benefits is defined benefit.

This report is prepared in accordance with the International Financial Reporting Standards ("IFRS") guidelines for post-retirement non-pension benefits as outlined in the International Accounting Standard 19 – Employee Benefits ("IAS 19").

The most recent full valuation was prepared as at December 31, 2017 based on the assumptions chosen by management at that date and in accordance with IAS 19.

The purpose of this valuation is threefold:

i) To determine the Corporation's liabilities in respect of post-retirement non-pension benefits at December 31, 2020;

ii) To determine the defined benefit costs to be recognized for fiscal year 2020; and

iii) To provide all other pertinent information necessary for compliance with IAS 19.

Note that all monetary figures in this report are rounded to the nearest hundreds of dollars and summated figures in this report may not match total figures due to rounding.

The intended users of this report include the Corporation and its auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

Included in the Appendix attached hereto are detailed accounting schedules containing the results of the valuation.

SECTION A —
VALUATION RESULTS

Section A.1 shows the key valuation results compared to previous year's figures projected from the most recent full valuation as well as a breakdown between active and retired individuals and type of benefit.

Section A.2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown an increase/decrease in the discount rate by 1% per annum.

Section A.3 shows the development of changes in the present value of defined benefit obligation as a result of the re-measurement at December 31, 2020.

Valuation Results

Section A.1—Valuation Results

Results from the actuarial valuation as at December 31, 2020 compared to previous year's figures projected from the most recent full valuation, disclosed in the consolidated Financial Statement as at December 31, 2019:

	December 31, 2019	December 31, 2020
Present Value of Defined Benefit Obligation (PV DBO)	**509,900**	**669,800**

	CY 2019	CY 2020
Current Service Cost	11,800	11,500
Interest Cost	17,100	17,800
Defined Benefit Cost Recognized in Income Statement	**28,900**	**29,300**
Actuarial (Gain)/Loss	-	133,500
Defined Benefit Cost Recognized In OCI	**-**	**133,500**
Defined Benefit Cost	**28,900**	**162,700**

The following table provides results from the actuarial valuation as at December 31, 2020 broken down by active (including LTD) and retired individuals for the post-retirement non-pension life benefit:

Dec. 31, 2020 PV DBO	Actives (incl. LTD)	Retirees	Total
Total	**302,500**	**367,300**	**669,800**

Sensitivity Analysis

Section A.2—Sensitivity Analysis

	Dec. 31, 2020 PV DBO	Difference	% Difference
Base Assumptions	669,800		
Discount Rate +1%	534,100	(135,700)	-20%
Discount Rate -1%	860,500	190,700	28%

Management's best estimate assumptions are those outlined in *Section C – Summary of Actuarial Method and Assumptions* in this report.

Development of Changes in the Present Value of Defined Benefit Obligation

Section A.3—Development of Changes in the Present Value of Defined Benefit Obligation

PV DBO at December 31, 2020	509,900
2020 Current Service Cost	11,500
2020 Benefit Payments	(2,900)
2020 Interest Cost	17,800
Expected PV DBO at December 31, 2020	**536,300**
Actuarial (Gain)/Loss at December 31, 2020	133,500
PV DBO at December 31, 2020	**669,800**

The increase indicated above of $133,500 in the PV DBO from the expected PV DBO at December 31, 2020 is due to the re-measurement of the liability; a breakdown of the changes is as follows:

Change in composition of active and retiree data (actual experience different from expected)	6,400
Change in assumptions:	
Discount Rate	135,700
Withdrawal	2,300
Mortality Improvement Table	(4,400)
Salary Scale	(6,500)
Total Actuarial (Gain)/Loss at December 31, 2020	**133,500**

Pursuant to IAS 19, the re-measurement of the PV DBO at December 31, 2020 based on the changes in the assumptions and experience is recognized immediately in other comprehensive income at December 31, 2020.

SECTION B —
PLAN PARTICIPANTS

Section B.1 sets out the summary information with respect to the plan participants valued in the current valuation compared to those valued in the previous valuation.

Section B.2 reconciles the number of participants in the previous valuation to the number of participants in the current valuation.

Participation Data

Section B.1—Participant Data

Membership data as at October 31, 2020 was received from the Corporation and included information such as name, gender, age, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

Although the data provided reflected status and benefit information as at October 31, the Corporation has indicated that no changes in status and other member data occurring from November 1 to December 31 are expected to be material to the valuation results.

We have reviewed the data and compared it to the data used in the previous valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of hire prior to date of birth;
- Ages under 18 or over 100;
- Abnormal levels of benefits and/or premiums; and
- Duplicate records

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

	December 31, 2017	December 31, 2020
Employee (incl. LTD) Count		
Male	31	29
Female	21	23
Total	**52**	**52**
Employee Average Service		
Male	8.8	10.1
Female	11.1	10.6
Total	**9.8**	**10.3**
Retiree Count		
Male	12	14
Female	4	6
Total	**16**	**20**

	Employee Count as of December 31, 2020			Employee Avg Service as of December 31, 2020		
Age	**Male**	**Female**	**Total**	**Male**	**Female**	**Total**
< 30	2	3	5	5	4	5
30 - 35	7	2	9	9	5	8
36 - 40	5	3	8	10	8	9
41 - 45	-	-	-	-	-	-
46 - 50	5	-	5	12	-	12
51 - 55	5	6	11	6	8	7
56 - 60	4	6	10	9	16	14
61 - 65	1	3	4	38	17	22
66 - 70	-	-	-	-	-	-
71 - 75	-	-	-	-	-	-
> 75	-	-	-	-	-	-
Total	**29**	**23**	**52**	**10.1**	**10.6**	**10.3**

Participant Reconciliation

Section B.2—Participation Reconciliation

	Actives	Disabled	Retired
As at December 31, 2017	**52**	**-**	**16**
New Entrants	10	-	-
Actives	-	3	5
Terminated	(5)	-	-
Retired	(5)	-	-
Deceased	-	-	(1)
Disabled	(3)	-	-
As at December 31, 2020	**49**	**3**	**20**

SECTION C — SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

Actuarial Method

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions for discount rates, mortality, and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and,
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The Defined Benefit Obligation and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by IAS 19. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. IAS 19 stipulates that the attribution period commences on the date when service by the employee first leads to benefits under the plan (whether or not the benefits are conditional on further service) and ends on the date when further service by the employee will lead to no material amount of further post-retirement non-pension benefits under the plan, other than from further salary increases.

For each employee not yet fully eligible for benefits, the Present Value of the Defined Benefit Obligation (PV DBO) is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

The PV DBO at December 31, 2020 is based on membership data as at October 31, 2020 and management's best estimate assumptions established for calculations as at December 31, 2020.

Management's Best Estimate Assumptions

The following are management's best estimate economic and demographic assumptions for calculations as at December 31, 2020.

Economic Assumptions

Discount Rate

The rate used to discount future benefits is assumed to be 2.50% per annum as of December 31, 2020 based on the Corporation's selection using the December spot rates curve from Fiera. This rate reflects the Corporation's expected projected benefit cash flows for post-retirement non-pension benefits and the market yields on high quality bonds at the time of preparing the valuation.

The assumption used in the previous valuation was 3.50% per annum as at December 31, 2017.

Salary Increase Rate

The rate used to increase salaries is assumed to be 2.75% per annum as of December 31, 2020. This rate has been chosen by the Corporation's management and reflect the expected Consumer Price Index adjusted for productivity, merit and promotion and for company-specific information.

This salary increase rate assumption used in the previous valuation was 3.20% per annum.

Demographic Assumptions

Mortality Table

The mortality tables used are as per the Canadian Institute of Actuaries Canadian Pensioners' Mortality Pension Experience Subcommittee final report dated February 11, 2014 (CIA Report). More specifically, the Canada Pensioners Mortality ("CPM") Table Public Sector (CPM2014 PUBL) has been used with the generational projection of mortality improvement based upon the CIA MI-2017 mortality improvement scale published in 2017.

The mortality improvement assumption has been updated from the CPM Improvement Scale B2-2014, which was used in the previous actuarial valuation for the Corporation.

Rates of Withdrawal

Termination of employment is assumed to be in accordance with the following withdrawal table:

Age Bucket	Current Analysis	Previous Analysis
18 – 29	2.90%	3.50%
30 – 34	2.15%	2.50%
35 – 39	1.85%	2.15%
40 – 49	1.45%	1.75%
50 – 54	1.25%	1.40%

Retirement Age

All active employees are assumed to retire at age 60 (or immediately if currently over age 60), which was based on the Corporation's retirement experience as well as the experience of other similar companies for which data was available.

This assumption remains unchanged from the previous valuation.

Disability

No provision was made for future disability and it was assumed that disabled employees would remain disabled until retirement at age 65. As noted by the Corporation, there are three individuals on disability, two of which are expected to return to work in 2021.

This assumption remains unchanged from the previous valuation.

Other Assumptions

Expenses and Taxes

For life coverage, it is assumed that 10% of the accrued benefit obligation reflects the cost of sponsoring and administering the program for life insurance. No additional information is available regarding the costs for the life insurance program.

These assumptions remain unchanged from the previous valuation.

SECTION D — SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation, based on information provided by and discussions with the Corporation.

Eligibility

All employees who retire from the Corporation are eligible for post-retirement life insurance benefits.

Participant Contributions

The Corporation shall pay 100% of the cost of the post-retirement life insurance benefits.

Past Service

Past service is defined as continuous service prior to joining the plan if the participant was employed by another electrical distribution company/hydro prior to joining the Corporation.

Length of Service

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

Summary of Benefits

Life Insurance

Upon retirement, all employees are entitled to post-retirement life insurance benefits, as per the MEARIE plan, based upon the following table:

Plan Option	Amount of Coverage	Eligibility
A	Flat $2,000.	Employee retires with less than 10 years of service in the Plan.
B, C1	50% of final annual earnings, reducing by 2.5% of final annual earnings each year for 10 years, to a final benefit equal to 25% of final annual earnings. Reduction occurs on the anniversary date of retirement.	Employee retires with 10 or more years of service in the Plan and was hired before June 16, 1989. or Employee was insured under the superseded plan and elected coverage under option 2, 3, or 4, or employee was not insured under the superseded plan.
C2	50% of final annual earnings.	Employee was insured under the superseded plan and was hired on or after May 1, 1967 and elected coverage under option 1 only.
C3	70% of final amount insured under the life plan immediately prior to retirement.	Employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under option 1 only.

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by Milton Hydro Distribution Inc. (the “Corporation”) as at December 31, 2020, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;
2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management’s best estimate assumptions (no provision for adverse deviations) and we express no opinion on them;
3. All known legal and constructive obligations with respect to the post-retirement non-pension benefits sponsored by and identified by the Corporation are included in the calculations; and
4. This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are not aware of any subsequent events after the date of completing this valuation that would have a significant effect on the valuation results contained herein.

The latest date on which the next actuarial valuation should be performed is December 31, 2023. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,
RSM CANADA CONSULTING LP

Stanley Caravaggio, FSA, FCIA
Director

Jamie Wong, ASA, ACIA
Supervisor

Toronto, Ontario

February 26, 2021

SECTION E — EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of Milton Hydro Distribution Inc.
Actuarial Valuation as at December 31, 2020

I hereby confirm, as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Milton Hydro Distribution Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) The membership data summarized in Section B is accurate and complete;

ii) The assumptions upon which this report is based as summarized in Section C, are management's best estimate assumptions and are adequate and appropriate for the purposes of this valuation; and

iii) The summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on December 31, 2020.

MILTON HYDRO DISTRIBUTION INC.

February 24, 2021	Igor Rusic
Date	Signature
Igor Rusic	Chief Financial Officer/ VP Finance
Name	Title

RSM

APPENDIX — DETAILED ACCOUNTING SCHEDULES

RSM

26/02/2021

Milton Hydro Distribution Inc.
Estimated Benefit Expense (IAS 19)
FINAL

	Actuals CY 2020 *	Projected ** CY 2021	Projected ** CY 2022	Projected ** CY 2023
Discount Rate at January 1	3.50%	2.50%	2.50%	2.50%
Discount Rate at December 31	2.50%	2.50%	2.50%	2.50%
Salary Increase Rate at December 31	2.75%	2.75%	2.75%	2.75%
Assumed Increase in Employer Contributions	actual	expected ***	expected ***	expected ***

A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet

	Actuals CY 2020 *	Projected ** CY 2021	Projected ** CY 2022	Projected ** CY 2023
Net Defined Benefit Liability/(Asset) as at January 1	509,917	669,785	692,164	713,494
Defined Benefit Cost Recognized in Income Statement	29,276	40,601	39,420	37,519
Defined Benefit Cost Recognized in Other Comprehensive Income	133,455	-	-	-
Benefits Paid by the Employer	(2,863)	(18,222)	(18,090)	(18,166)
Net Defined Benefit Liability/(Asset) as at December 31	669,785	692,164	713,494	732,847

B. Determination of Defined Benefit Cost

B1. Determination of Defined Benefit Cost Recognized in Income Statement

	Actuals CY 2020 *	Projected ** CY 2021	Projected ** CY 2022	Projected ** CY 2023
Current Service Cost	11,479	24,084	22,342	19,908
Interest Cost	17,797	16,517	17,078	17,610
Defined Benefit Cost Recognized in Income Statement	29,276	40,601	39,420	37,519

B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income

	Actuals CY 2020 *	Projected ** CY 2021	Projected ** CY 2022	Projected ** CY 2023
Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	129,163	-	-	-
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	(2,158)	-	-	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments	6,450	-	-	-
Return on Plan Assets (Excluding Amounts Included in Net Interest Cost)	-	-	-	-
Change in Effect of Asset Ceiling	-	-	-	-
Defined Benefit Cost Recognized in Other Comprehensive Income	133,455	-	-	-
Total Defined Benefit Cost	162,731	40,601	39,420	37,519

C. Change in the Present Value of Defined Benefit Obligation

	Actuals CY 2020 *	Projected ** CY 2021	Projected ** CY 2022	Projected ** CY 2023
Present Value of Defined Benefit Obligation as at January 1	509,917	669,785	692,164	713,494
Current Service Cost	11,479	24,084	22,342	19,908
Interest Cost	17,797	16,517	17,078	17,610
Benefits Paid	(2,863)	(18,222)	(18,090)	(18,166)
Net Actuarial Loss/(Gain)	133,455	-	-	-
Present Value of Defined Benefit Obligation as at December 31	669,785	692,164	713,494	732,847

* The expected December 31, 2020 PV DBO and CY 2020 defined benefit cost are calculated based on membership data and management's best estimate assumptions at December 31, 2017.

** Projected CY 2021, 2022 and 2023 results are provided for informational purposes only. Significant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

*** Based on exepcted benefits to be paid to those eligible for benefits.

RSM

Milton Hydro Distribution Inc.
Estimated Benefit Expense (IAS 19)
FINAL

	Actuals CY 2020 *	Projected ** CY 2021	Projected ** CY 2022	Projected ** CY 2023
Discount Rate at January 1	3.50%	2.50%	2.50%	2.50%
Discount Rate at December 31	2.50%	2.50%	2.50%	2.50%
Salary Increase Rate at December 31	2.75%	2.75%	2.75%	2.75%
Assumed Increase in Employer Contributions	actual	expected ***	expected ***	expected ***

D. Calculation of Component Items

	Actuals CY 2020 *	Projected ** CY 2021	Projected ** CY 2022	Projected ** CY 2023
Interest Cost				
Present Value of Defined Benefit Obligation as at January 1	509,917	669,785	692,164	713,494
Benefits Paid	(1,432)	(9,111)	(9,045)	(9,083)
Accrued Benefits	508,486	660,674	683,119	704,411
Interest Cost	17,797	16,517	17,078	17,610
Expected Present Value of Defined Benefit Obligation as at December 31				
Present Value of Defined Benefit Obligation as at January 1	509,917	669,785	692,164	713,494
Current Service Cost	11,479	24,084	22,342	19,908
Benefits Paid	(2,863)	(18,222)	(18,090)	(18,166)
Interest Cost	17,797	16,517	17,078	17,610
Expected Present Value of Defined Benefit Obligation as at December 31	536,330	692,164	713,494	732,847

E. Net Actuarial Loss/(Gain)

	Actuals CY 2020 *	Projected ** CY 2021	Projected ** CY 2022	Projected ** CY 2023
Net Actuarial Loss/(Gain) as at December 31				
Expected Present Value of Defined Benefit Obligation	536,330	692,164	713,494	732,847
Actual Present Value of Defined Benefit Obligation	669,785	692,164	713,494	732,847
Net Actuarial Loss/(Gain) as at December 31	133,455	-	-	-

* The expected December 31, 2020 PV DBO and CY 2020 defined benefit cost are calculated based on membership data and management's best estimate assumptions at December 31, 2017.

** Projected CY 2021, 2022 and 2023 results are provided for informational purposes only. Significant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

*** Based on exepcted benefits to be paid to those eligible for benefits.

rsmcanada.com

EXHIBIT 4

ATTACHMENT 4-5

2021 RSM ACTUARIAL REPORT

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January 14, 2022

DELIVERED BY E-MAIL: rusici@miltonhydro.com

Mr. Igor Rusic
CFO/VP Finance & Administration
Milton Hydro Distribution Inc.
200 Chisholm Drive
Milton, ON L9T 3G9

Dear Mr. Rusic:

Re: Milton Hydro Distribution Inc. ("the Corporation") – Actuarial Extrapolation as at December 31, 2021: Post-Retirement Non-Pension Benefit Plan

RSM Canada Consulting LP has been engaged by the Corporation to provide an update to the accounting extrapolations regarding the Corporation's post-retirement non-pension benefits for fiscal year ending December 31, 2021. Attached are accounting exhibits providing the results of the roll-forward of the Corporation's liabilities for fiscal year 2021. Also included in the exhibits for illustrative purposes only is an extrapolation for fiscal years ending December 31, 2022 and December 31, 2023.

The most recent full actuarial valuation performed for the Corporation was at December 31, 2020 with our final report dated February 26, 2021 provided to the Corporation.

The intended users of this letter and attachments include the Corporation and its auditors for financial reporting in compliance with the accounting guidelines in respect of its post-retirement non-pension benefit plan for FY 2021. The calculations were performed in accordance with the International Financial Reporting Standards (IFRS) guidelines, specifically International Accounting Standards 19 (IAS 19) Employee Benefits.

We also note the revision of the FY 2021 benefit payments for post-retirement non-pension benefits to $2,802.15, which reflects the actual benefits paid for the year.

Our calculations are based on the same benefit plan provisions, data, assumptions, and methodology as summarized in our actuarial valuation report at December 31, 2020, with the exception of the discount rate assumption chosen by management which was changed from 2.50% to 3.10% per annum at December 31, 2021. The discount rate assumption is based on the projected benefit cash flows for the post-retirement non-pension benefits of the Corporation and the Fiera Capital yield curve for December 31, representing current high quality bond yields in the market.

In addition to the attached accounting exhibits which contain the detailed extrapolation results, we have also provided sensitivity analysis at December 31, 2021 below. The sensitivity analysis shows the change in the present value of the defined benefit obligation at December 31, 2021 by increasing or decreasing the discount rate by 1% increments. The sensitivity is done separately for each assumption, while keeping other assumptions the same.

	Base	Discount Rate +1%	Discount Rate -1%
PV DBO @ Dec. 31, 2021	617,600	501,400	778,900
% Difference		-19%	26%

We are not aware of any subsequent events that would have a significant impact on the results of our calculations contained herein.

If you have any questions regarding the above or the attached exhibits, please do not hesitate to give us a call.

Yours truly,

Stanley Caravaggio

Stanley Caravaggio, FSA, FCIA
Director
[Telephone: 416.408.5306]
[E-mail: stanley.caravaggio@rsmcanada.com]

SC:ecs

Copy: Jamie Wong, Erica Zhao (RSM Canada)

RSM

Milton Hydro Distribution Inc.
Estimated Benefit Expense (IAS 19)
FINAL

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023
Discount Rate at January 1	2.50%	3.10%	3.10%
Discount Rate at December 31	3.10%	3.10%	3.10%
Salary Increase Rate at December 31	2.75%	2.75%	2.75%
Assumed Increase in Employer Contributions	actual	expected ***	expected ***

A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023
Net Defined Benefit Liability/(Asset) as at January 1	669,785	617,629	638,322
Defined Benefit Cost Recognized in Income Statement	40,794	38,783	40,041
Defined Benefit Cost Recognized in Other Comprehensive Income	(90,148)	-	-
Benefits Paid by the Employer	(2,802)	(18,090)	(18,166)
Net Defined Benefit Liability/(Asset) as at December 31	617,629	638,322	660,197

B. Determination of Defined Benefit Cost

B1. Determination of Defined Benefit Cost Recognized in Income Statement

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023
Current Service Cost	24,084	19,917	20,535
Interest Cost	16,710	18,866	19,506
Defined Benefit Cost Recognized in Income Statement	40,794	38,783	40,041

B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023
Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	(90,148)	-	-
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	-	-	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments	-	-	-
Return on Plan Assets (Excluding Amounts Included in Net Interest Cost)	-	-	-
Change in Effect of Asset Ceiling	-	-	-
Defined Benefit Cost Recognized in Other Comprehensive Income	(90,148)	-	-
Total Defined Benefit Cost	(49,354)	38,783	40,041

C. Change in the Present Value of Defined Benefit Obligation

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023
Present Value of Defined Benefit Obligation as at January 1	669,785	617,629	638,322
Current Service Cost	24,084	19,917	20,535
Interest Cost	16,710	18,866	19,506
Benefits Paid	(2,802)	(18,090)	(18,166)
Net Actuarial Loss/(Gain)	(90,148)	-	-
Present Value of Defined Benefit Obligation as at December 31	617,629	638,322	660,197

* The expected December 31, 2021 PV DBO and CY 2021 defined benefit cost are calculated based on membership data and management's best estimate assumptions at December 31, 2020.

** Projected CY 2022 and 2023 results are provided for informational purposes only. Significant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

*** Based on exepcted benefits to be paid to those eligible for benefits.

Milton Hydro Distribution Inc.
Estimated Benefit Expense (IAS 19)
FINAL

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023
Discount Rate at January 1	2.50%	3.10%	3.10%
Discount Rate at December 31	3.10%	3.10%	3.10%
Salary Increase Rate at December 31	2.75%	2.75%	2.75%
Assumed Increase in Employer Contributions	actual	expected ***	expected ***

D. Calculation of Component Items

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023
Interest Cost			
Present Value of Defined Benefit Obligation as at January 1	669,785	617,629	638,322
Benefits Paid	(1,401)	(9,045)	(9,083)
Accrued Benefits	668,384	608,584	629,239
Interest Cost	16,710	18,866	19,506
Expected Present Value of Defined Benefit Obligation as at December 31			
Present Value of Defined Benefit Obligation as at January 1	669,785	617,629	638,322
Current Service Cost	24,084	19,917	20,535
Benefits Paid	(2,802)	(18,090)	(18,166)
Interest Cost	16,710	18,866	19,506
Expected Present Value of Defined Benefit Obligation as at December 31	707,777	638,322	660,197

E. Net Actuarial Loss/(Gain)

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023
Net Actuarial Loss/(Gain) as at December 31			
Expected Present Value of Defined Benefit Obligation	707,777	638,322	660,197
Actual Present Value of Defined Benefit Obligation	617,629	638,322	660,197
Net Actuarial Loss/(Gain) as at December 31	(90,148)	-	-

* The expected December 31, 2021 PV DBO and CY 2021 defined benefit cost are calculated based on membership data and management's best estimate assumptions at December 31, 2020.

** Projected CY 2022 and 2023 results are provided for informational purposes only. Significant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

*** Based on exepcted benefits to be paid to those eligible for benefits.

EXHIBIT 4

ATTACHMENT 4-6
CORPORATE PURCHASING POLICY

POLICY

Corp-01: Corporate Purchasing Policy

Document Owner	Milton Hydro Holdings Inc	
Policy Owner	Procurement	
Reviewed by	Senior Management Team	August 3, 2021
Approved by	Board of Directors	August 30, 2021
Document Distribution	Policy Binder, Intranet	
This policy is for internal use only		

Note: The most up-to-date versions of all policies are posted on the Intranet under Policies & Procedures. Printed copies should not be relied upon to be the most current version.

1. APPLICATION

This Policy applies to Milton ("Company"), its subsidiaries and all their employees, subject to any applicable Collective Agreement requirements.

The following describes the function of the Purchasing Department and the policies of Milton Hydro Holdings Inc. and its subsidiaries in purchasing all supplies, material, equipment, and services (goods and services). Wherever we can influence the life cycle of goods and services, each department of the Corporation shall apply the reduce, reuse, recycle and recover methodology, to reduce our environmental impact.

2. PURPOSE

The procurement process strives to ensure the most cost effective and efficient products and services are purchased and that all purchased items meet regulatory and safety compliance standards. Purchasing practices must include a review of potential health and safety hazards to ensure that potential hazards are adequately controlled.

3. SCOPE

This policy applies to all staff who are authorized to purchase goods and services for use in the workplace.

4. OBJECTIVES

4.1. Obtaining goods or services for specified quality and quantity at the best price with sufficient lead time for delivery.

4.2. Obtaining quotations and/or issuing tenders in accordance with company guidelines. On occasion, when departments require cost estimates to determine whether or not to proceed with a purchase, suppliers must be advised that these are study estimates only, and that any purchases will go through the standard purchasing process. All information, including alternate quotes, are to be submitted to the purchaser unless otherwise instructed.

4.3. Completing traditional purchase transactions by issuing purchase orders to ensure deliveries and schedules are met.
4.4. Maintaining inventory levels consistent with the needs and schedules of the department, and at practical levels based on historical use and emergency stock requirements.
4.5. Safely disposing of all obsolete and surplus material after receiving notification from all affected departments.
4.6. Maintaining the highest professional, ethical and moral business practices.
4.7. Consulting with the Health and Safety Manager or other staff with expertise in order to obtain information relating to specialized technical or other purchasing specifications and needs.
4.8. Obtaining supplier or manufacturer catalogues, specifications and related information.
4.9. Except where a non-competitive commodity is required, to make all purchases on a competitive basis, consistent with corporate standards, quality and service, all things being equal, preference being given first to goods of local manufacturers and second to goods offered by local suppliers.
4.10. Sourcing potential suppliers, interviewing sales representatives, informing all applicable departments of the information received regarding new or existing materials, equipment, processes and techniques and retaining on file for reference.
4.11. Arranging for relevant training and/or demonstrations from the supplier as necessary.
4.12. Working closely with staff and others to ensure proper material specification and compliance with minimum legal and regulatory standards.

5. DEFINITIONS

5.1. REQUEST FOR QUOTATION (RFQ)

A request for prices on specific goods and/or services from selected vendors, which are submitted verbally, in writing or electronically. The RFQ provides a detailed description of the goods and services to be purchased. The RFQ evaluation is typically based upon quality and price. RFQs are best suited to standardized products and services.

5.2. REQUEST FOR TENDER (RFT)

A document used to request sealed supplier responses for goods and/or services based on a defined need, such as delivery requirements, performance specifications, terms and conditions. An RFT focuses the evaluation criteria predominantly on quality, price, and delivery requirements. RFTs may be invitational (i.e., three or more suppliers are asked to submit a bid) or open (i.e., the bid document is available to any supplier that deems itself capable of meeting the needs and specifications defined in the RFT).

5.3. REQUEST FOR PROPOSAL (RFP)

A document used to request suppliers to provide solutions for the delivery of complex products or services or to provide alternative options or solutions. The process uses predefined evaluation criteria (price is not the only factor). The RFP leaves all or part of the precise structure and format of the response to the discretion of the proponents.

5.4. REQUEST FOR INFORMATION (RFI)

The purpose of an RFI is to gather general supplier or product information. This mechanism may be used when researching a contemplated procurement and the characteristics of the ideal solution have not yet been determined. RFIs normally contribute to the final version of a subsequent RFP.

5.5. PURCHASE ORDER

A purchasing document that is a legal contract and is used to formalize a transaction with a vendor. Purchase Orders must be provided to the vendor prior to receiving the goods and/or services.

5.6. BLANKET PURCHASE ORDER

A special type of Purchase Order that is open for use for a specific period, generally a calendar year. It is intended for repetitive purchases of goods or services.

5.7. PURCHASING CARD (CREDIT CARD)

A company provided credit card intended to facilitate the purchase and payment of goods and/or services.

5.8. EMERGENCY MATERIALS OR SERVICES

Emergency requirements shall be defined as items or services, which must be sourced quickly, generally outside normal working hours where time is of the essence. Examples of situations that may require emergency items include: correction of safety problems, loss of service, large economic loss, spill of pollutants, inconvenience to the public, etc. Emergency procedures may require temporary suspension of provisions of the Purchasing Policy as determined by a Director or Executive member of Milton Hydro Holdings Inc. and/ or affiliates.

A lack of adequate planning does not constitute an allowable emergency unless approved by an Executive Team member.

5.9. LIMITS OF AUTHORITY

Limits of Authority are set as per Section 7.1 below (Corporate Expenditure Authorization Policy) and represent the minimum authority required. Approval for purchasing supplies and services is based on the total estimated dollar value, including any agreed-upon renewals, and is exclusive of applicable taxes. Purchases shall not be split to bypass approval limits.

5.10. VERBAL AUTHORIZATION

Employees are advised that a verbal authorization or commitment on their part to a vendor to proceed with the supply of goods or services, can form a legal contract that is valid and enforceable under law the same as any written contract document. Employees may not enter into verbal agreements with other parties on behalf of the Company and all authorizations should be in writing in the absence of a contract and/ or purchase order.

6. PURCHASING METHODS

Goods or services with a value exceeding $20,000 should be acquired through a competitive process such as RFQ or RPF/RFT, except when the sole source procurement criteria described below are met or in cases of emergency.

6.1. RFQ

Quotations shall be obtained from approved suppliers for materials or services to maintain competitive pricing. Purchasing, at its discretion, may source materials based on email or facsimile quotations as dictated by circumstances.

Standard practice will be to solicit quotes from at least three vendors whenever possible. As a minimum, Formal Written Quotes shall be sought from any vendor when a Purchase exceeds $20,000.

6.2. RFT/RFP

An RFT or RFP will be used for the purchases of goods and services relating to significant projects in excess of $100,000. The decision as to whether to use an RFT or RFP will be made by the user department. All FORMAL procurements regardless of value should be conducted by/through the Procurement department. The user department may take the lead to participate in and support the development of the RFT/RFP but MUST defer to the Purchasing department as part of the development process. RFTs/RFPs will include, as a minimum, the following information:

6.2.1. A description of the goods or services required;
6.2.2. Full disclosure of the evaluation criteria, process, and methodology to be used in assessing submissions, including identification of criteria considered mandatory, any technical standards that need to be met, and methods of weighting and the criteria;
6.2.3. A period of irrevocability where bids cannot be withdrawn;
6.2.4. Documents will have a minimum response time of 15 calendar days and must have a closing date set on a normal working day during normal business hours; and
6.2.6. Review committee consisting of three (3) persons, including the CFO or their designate, user department and Purchasing Supervisor. The review committee will evaluate the submissions and select the successful vendor. This decision must be documented and signed off by each member of the review committee.

Where RFTs are required on contracts for construction work or other projects undertaken by the Corporation, the head of the department concerned will be responsible for the preparation of all necessary plans and specifications. Following the preparation of the tender specifications, the RFT document shall be sent to the Purchasing department for attachment of the standard purchasing documents to the tender and shall only be used for Construction type work. The Purchasing department will be responsible for sending the tender to the invited parties.

6.3. SOLE SOURCE PROCUREMENT

Sole source procurement may be considered in the following instances:

6.3.1 When the goods and services can be obtained only from one person or firm;
6.3.2 The expertise of an individual organization or individual is deemed to be specifically required by the company;
6.3.3 When competition is precluded because of the existence of patent rights, copyrights, secret processes, control of raw material or other such conditions;
6.3.4 When it is the only product or service that has been approved by the company for use in the distribution system;
6.3.5 When the procurement is for electric power or energy, gas, water, or other utility services where is would not be practical to allow a contractor other than the utility company itself to work upon the system;
6.3.6 When the procurement is for technical services in connection with the assembly, installation, or servicing of equipment of a highly technical or specialized nature;
6.3.7 When the procurement is for parts or components to be used as replacements in support of equipment specifically designed by the manufacturer;
6.3.8 The contractor is already at work on the site (based on an existing Purchase Order), and it would not be practical to engage another contractor; or,
6.3.9 Specific Health and Safety items as approved by the Manager of Health and Safety.

Sole source justification should be thoroughly documented, using the Sole or Single Source Justification Form (see Appendix D). The burden of proof to justify sole source procurement falls to the purchase requisitioner who should prepare a document called Sole Source Justification and Approval. Sole sourcing is not appropriately justified and justifiable when used as a method of selecting a preferred vendor.

6.4. NEGOTIATING A PURCHASE

6.4.1 The Purchasing Department may, under one of the following conditions, purchase by negotiating with one or more sources or bidders as permitted in accordance with the RFx solicitation document. Under the following cases, the requirements for inviting tenders and formal quotations may be waived.

- The goods or services are in short supply due to market conditions, in the judgment of the Purchasing Supervisor;

- Two or more identical bids have been received;

- All bids received failed to meet the specifications and/or tender terms and conditions and it is impractical to recall tenders or formal quotations;

- Certain professional services which require specialized technical knowledge to ensure compliance with structural, civil, environmental, or other regulatory standards, or which are critical to the Corporation’s information technology support systems.

6.5 MHDI PURCHASING CARD

See Appendix A (attached)

7. PURCHASING PROCEDURES

7.1. AUTHORIZATION LIMITS

The authorization limits are set out in the Corporate Expenditure Authorization Policy.

7.2. PURCHASE ORDERS

An approved and signed Purchase Order is required for all purchases greater than $3,500, except in the instances noted in Appendix B. This requirement also applies to project change orders and other modifications (e.g., changes required due to revised engineering specifications) to the original project terms.

BID SOLICITATION GUIDELINES

Inventory purchases require a purchase order regardless of the spend amount. Purchases shall be acquired in accordance with the bid solicitation guidelines herein. Purchases under $20,000 shall require one written quote. Purchases between $20,000 and $150,000 shall require, subject to the exceptions noted in this policy, three written competitive quotes and a formal RFx process will be used for purchases over $150,000. There may be circumstances where the required procurement is deemed a higher risk to the organization (a "complex procurement") and may require a more formal procurement and/or contract review process, which may introduce additional time to initiate the procurement process, legal review, and other internal stakeholder consultation. The engagement of a supplier or third party for services that involve issues relating to health and safety, sharing of confidential information (in particular, Milton's customer or employee data), third-party access or integration to systems, or has the potential to pose reputational risk are all deemed higher risk and you should engage with Procurement as early as possible to conduct a risk assessment.

BID SOLICIATION GUIDELINES		
THRESHOLD	**GUIDELINES**	**RESPONSIBILITY**
Under $20,000	One quote, supplier must agree to Milton PO Terms and Conditions	Department or Procurement Services
$20,000 to $150,000	Three written quotes, selected supplier must agree to Milton PO Terms and Conditions	Department or Procurement Services
$150,000 and over	Formal competitive procurement – RF(x) process	Procurement Services
Complex Purchases (any value)	Any value Any RF(x) process	Procurement Services and CEO

All Purchase Orders require supervisor approval in accordance with the Corporate Expenditure Authorization Policy (see Section 7.1) prior to submitting the Purchase Order to the vendor.

PURCHASE ORDER EXCEPTIONS

7.2.1 Purchases, project change orders, and other modifications less than $3,500 do not require a Purchase Order. These expenditures require supervisor approval in accordance with the Corporate Expenditure Authorization Policy (see Section 7.1).

7.2.2 Purchase Orders are not required for the exceptions noted in Appendix B (regardless of dollar value) where an alternate approval procedure is in place. Such alternate approval must be in accordance with the Corporate Expenditure Authorization Policy (see Section 7.1).

7.3. SIGNING AUTHORITY AND BUDGET APPROVALS

Purchases will be made according to approvals obtained by the appropriate signing authorities and approved budgets. Students are not entitled to participate in the requisitioning process. Goods and services are not to be provided until a valid purchase order is issued by the Procurement department to an approved source of supply.

7.4. INVENTORY ITEMS - NEW

Purchases will be initiated based on established stock order points and advice from user departments. Vendor contracts may be used for repeat purchases, for a specified period.

7.5. INVENTORY ITEMS - USED

Opportunities to purchase used material will come from a variety of sources. A list of material for sale will be obtained from the vendor and if the Company is interested in the items, a bid will be submitted to the vendor. Whenever feasible, the products should be inspected in person prior to submitting a bid. Purchases should be made subject to testing by the Company (possibly performed by a 3rd party in accordance with regulation 22/04, if applicable) and payment should not be made until after the products have tested satisfactorily.

7.6. NON-INVENTORY ITEMS (INCLUDING CAPITAL PURCHASES)

This category covers items that are not held in stock but are ordered based on requests from the user department. Examples of these types of items are furniture, office equipment, tools, IT equipment, vehicles, capital projects for the utility infrastructure, and services such as building repairs and maintenance.

For sub-contractor services, the sub-contractor shall be approved by the contractor preapproval process which will supply evidence of sufficient insurance coverage and WSIB clearance prior to commencing any work. Depending on the length of the project, the certificates may need to be updated on a regular basis.

7.7. EMERGENCY ITEMS / SERVICES

This category covers items that must be sourced quickly, generally outside normal working hours where time is of the essence and are not held in stock. Initiation of emergency purchases are the responsibility of the affected department, generally outside of normal working hours and may require suspension of the provisions of the Purchasing Policy. Any suspension of the Purchasing Policy shall be reported in writing or electronically by the affected department to the Chief Financial Officer and Purchasing Supervisor on the first regular working day following the emergency. Details on the purchase and determining factors for suspension of the Purchasing Policy shall be included in the information provided.

7.8. CONSULTING SERVICES

This category covers the sourcing of the services of outside consulting and legal firms to provide services that are included in the approved budget. The user department or Purchasing may source consulting/legal services. If necessary, a Non-Disclosure Agreement (“NDA”) should be used.

For each agreement, the following should be defined in writing prior to any work beginning:

- Clearly defined project Scope
- Deliverables with due dates
- Payment schedule

All non-budgeted consulting/legal services shall adhere to the authorization limits outlined in the Corporate Expenditure Authorization Policy.

7.9. SCRAP, OBSOLETE, OR SURPLUS ITEMS

Scrap, obsolete or surplus items shall be safely disposed of upon the advice of a user department by sale, or otherwise as deemed appropriate, in the best interest of the Company.

7.10. PERFORMANCE BONDS

Performance bonds are required for all capital construction projects in which the vendor's quote (i.e., exclusive of goods and materials supplied) exceeds $100,000. The contractor shall, prior to the commencement of the work, provide:
(a) a labour and material payment bond in the amount of 50% of the Contract Price; and
(b) a performance bond in the amount of 50% of the Contract Price.

Any requirement for performance bonds will be defined in the tender documents.

In instances of breach of contractual performance obligations where a performance bond has been provided, the Purchasing Supervisor will use discretion in determining the necessary and appropriate remediation options to pursue to satisfactorily complete the project in the most efficient manner.

7.11. NEW MATERIALS AND EQUIPMENT

All materials purchased for use to construct a utility electrical distribution system must meet the requirements of Ontario Regulation 22/04. New equipment and material that has not previously been used must be brought to the attention of the Engineering department to ensure regulatory and operations requirements are satisfied.

When new health and safety related equipment is being proposed, it must be brought to the attention of the Manager of Health and Safety to ensure Regulatory, and Health and Safety requirements are satisfied.

7.12. SUPPLIER APPROVAL AND REVIEW

Materials, supplies, equipment, or services may not be purchased from contractors or suppliers that are not approved on the Company Approved Suppliers List, except for administrative items and in emergency situations (as defined in Sections 5.8 and 7.7 of this policy). The Approved Suppliers List is maintained on an ongoing basis and is formally reviewed on an annual basis by the Purchasing Supervisor. New contractors and suppliers may only be approved once the contractor and vendor pre-approval process has been satisfactorily completed. Any deviation from this requirement will require Purchasing Supervisor approval.

Supplier performance will be reviewed annually. Suppliers who fail to deliver satisfactory products, and/or do not deliver on time despite requests for corrective actions, will be removed from the Approved Supplier List. Any supplier of goods or services who knowingly contravenes this policy may be prohibited from bidding on future contracts or performing work on behalf of the Company.

Any supplier of goods and/or services who knowingly misrepresents any detail pertaining to a good or service considered for purchase, or misrepresents the qualifications or experience of an employee, may be prohibited from bidding on future contracts for the supply of goods and/or services.

7.13. PURCHASING CARDS

The Company's Purchasing Card is used for the purchase of goods and services. See Appendix A (attached for full procedure)

7.14. CONFIDENTIALITY

7.14.1 Sealed bids and quotes shall remain confidential from third parties.
7.14.2 Personal, proprietary, and third-party information will be protected.
7.14.3 The confidentiality of information received during the course of business must be respected and not used for personal gain
7.14.4 Any personal interest that may impinge or may be construed to impinge on an employee's impartiality in any circumstance in the performance of their duties must be reported to the Chief Financial Officer or President and Chief Executive Officer.

7.15. PURCHASING CARDS

There are certain circumstances identified where particular goods and services do not require competitive procurement and therefore exempt from the bid solicitation guidelines. The exempted purchases are noted in Appendix C – Competitive Procurement Exemptions.

8. CODE OF CONDUCT

8.1. COMPLIANCE

Suppliers/Contractors for are to be respected and given fair and equal treatment. Employees shall operate in a manner that will not result in preferential treatment of any supplier. Information from suppliers/contractors is deemed confidential and proprietary and is to be kept confidential.

8.2. ETHICAL BUSINESS PRACTICES

In providing goods and services to Milton suppliers/contractors must adhere to ethical business practices including:

(a) Performing all work in a professional and competent manner and in accordance with the terms and conditions of the contract
(b) Complying with all applicable laws including safety and labour codes (both domestic and international as may be applicable)

8.3. ILLEGAL OR UNETHICAL BIDDING PRACTICES

Milton will hold its Suppliers/Contractors to a high standard of ethics. They are not to engage in illegal or unethical bidding practices, including:

(a) Bid-rigging, price-fixing, bribery or collusion or other practices prohibited by federal or provincial statues;
(b) Offering gifts or favours to Milton employees, members of the Board or any other representative of the Milton;
(c) Engaging in any prohibited communications during a procurement process;
(d) Submitting inaccurate or misleading information in response to a procurement opportunity; and
(e) Engaging in any other activity that compromises Milton's ability to run a fair procurement process.

8.4. CONFLICTS OF INTEREST

All employees, suppliers and contractors participating in a procurement process must declare any perceived possible or actual conflicts of interest. Where a supplier/contactor is retained to participate in the development of a Solicitation Document or the specifications for inclusion in a Solicitation Document that supplier/contractor will not be allowed to respond directly or indirectly to that Solicitation Document.

9.HEALTH & SAFETY

9.1. COMPLIANCE

All goods and/or services purchased by the Company must comply with all appropriate Federal, Provincial and Municipal legislation, regulations, and standards as well as all Company policies and procedures.

The requirements of the Regulations for Industrial Establishments with regard to Section 7, Pre-Start Safety Review shall be met.

The purchaser, in consultation with the Health and Safety Manager or other knowledgeable staff person, will ensure compliance with health and safety legal, and regulatory requirements.

All chemical purchases must be administered by the purchasing department.

Safety Data Sheets ("SDSs") and appropriate labels must be obtained with each delivery of any controlled product as defined by the Workplace Hazardous Material Information System ("WHMIS") legislation. It is the responsibility of the Purchaser to ensure that a SDS is available and on file.

In addition to meeting ESA regulatory requirements, electrical equipment and conductors shall meet the Ontario Electrical Safety Code, CSA Standards, and other applicable legal and regulatory requirements.

9.2. ACCESSIBILITY FOR ONTARIANS WITH DISABILITIES

The Company will have regard for persons with disabilities in any decision to purchase goods and services. The Company is committed to accessibility principles in accordance with the Accessibility for Ontarians with Disabilities Act, 2005.

Appendix A

Corporate Credit Card Procedures

Part A - Corporate Credit Card Appropriate Uses and Responsibilities

Corporate credit cards will only be used for appropriate business expenditures. The charging of personal expenditures to the corporate credit card is prohibited. Disciplinary action may be taken for inappropriate use of corporate credit cards.

1. Appropriate Use

Examples of appropriate uses of corporate credit cards include:

a) business travel expenses (i.e., accommodation, meals, parking)
b) job site requirements for items not held in warehouse
c) emergencies (i.e., ice storms)
d) conference registration fees

Examples of prohibited uses of corporate credit cards include (but are not limited to):

a) personal expenses
b) withdrawal of cash/cash advances
c) non-work order related capital (i.e., furniture, equipment, computer hardware/software) unless previously approved

Areas of Uncertainty

The above list is provided as a guide only. In situations where there is doubt about the appropriate use of the corporate credit card, the employee shall seek the guidance of their supervisor.

2. Responsibilities

a) Employees issued a corporate credit card are responsible for:
   - ensuring the cards are used only for appropriate business expenses (refer to section 1 above)
   - ensuring that only the employee whose name appears on the card uses the card (with the exception of department cards)
   - retaining receipts and providing explanations for all card transactions. The occurrence of continual missing receipts may result in cancellation of the corporate credit card
   - submitting a completed and approved expense form when card expenditure has been incurred
   - returning the corporate credit card to their supervisors upon termination

b) The CFO is responsible for:
   - determining which employees require a corporate credit card for business and the applicable credit limit for each corporate credit card
   - limiting the issue of corporate credit cards to those employees who require a card for utility business
   - cancelling the corporate credit cards from terminating employees

c) The Authorizing Manager/Vice President is responsible for:

- reviewing and authorizing corporate credit card expense accounts of employees on a timely basis
- identifying and requesting any credit or transaction level limits required for individual cards
- collecting the corporate credit cards from terminating employees

d) The Finance department is responsible for:

- ensuring that all corporate credit card transactions are properly authorized
- processing payments for corporate credit card statements on a timely basis to ensure correct coding and appropriate payments are being made.

Part B - Corporate Credit Card Statement Payment Procedures

1. Employees must retain detailed original receipts in addition to the credit card receipt and note the purpose of the expenses on the back of each receipt.

2. The employee will submit the detailed original receipts along with a completed expense form to the appropriate authorizing supervisor for authorization.

3. Charges for items where the receipt has been misplaced must be explained to the authorizing supervisor who must initial the specific charge and indicate, “receipt missing” beside it. The occurrence of continual missing receipts may result in cancellation of the corporate credit card as well as possible disciplinary action.

4. The authorizing supervisor will confirm that the charges are justified and appropriate before authorizing (signing) the expense form for payment.

5. The approved expense form and original receipts will be forwarded to the cardholders Senior Management Team member for final approval.

6. Accounts Payable must receive the completed documents one week prior to the credit card statement due date.

7. Accounts Payable will verify that the appropriate approvals have been received and schedule payment of the credit card balance to avoid unnecessary late payment charges.

Appendix B

Items Not Requiring a Purchase Order

Certain goods, services and payments may not require a purchase Order. Controls other than approved Purchase Orders are in place for these items and must be followed.

Description	Control Process to be Followed
Annual Bond Rating and interest payments	Bond rating fees are to be approved by the CFO
Financial Audit Services and Expenses	External audit work and related fees are approved by the Audit Committee of the Board of Directors. The audit fee payment is approved by the CFO or delegate.
Banking Services including Credit Cards	Banking arrangements are made and reviewed by CFO or delegate
Board or Committee Requested Procurements	Authorization given by the Board Chair or Committee Chair.
Customer Rebates and incentives (i.e. CDM)	Customer rebates and incentives must be signed off by the CFO
Debenture/Dividend payments	Financial arrangements are made by the CFO or delegate
Developer Rebates and Deposit Refunds	Rebates and Deposit refunds are reviewed and approved by Finance and Network Operations or Network Services Lead
Executive Team Requested Procurements	Authorization given by the member of the Executive Team in accordance with their spending authority in accordance with the Corporate Expenditure Authorization policy
Employee Medicals	Medical arrangements are made and approved by Human Resources or CEO Office
Corporate Social Responsibility/Grants and Charitable Donations	Selection and payments for Corporate Social Responsibilities/Grants and Charitable Donations are determined and approved by the Executive Team and subsequently approved by the Board of Directors.
Honorariums – (i.e. Board of Directors)	Payments are approved as per the stipend schedule and meeting fees determined at the onset of each fiscal year.
Human Resources required services which are confidential in nature	Approved by the CEO Office or Human Resources
IESO Cost of Power Payments	Payments are approved and signed by the CFO.
Corporate Industry Associations (i.e. Board of Trades)	Fees are approved by the appropriate SLT member or Executive Team Member.
Employee Industry & Professional Membership Fees	Membership Fees are approved in by the Business unit based on applicable HR Policy or Procedures.
Insurance Premiums	Insurance arrangements and approvals are to be made by the CFO or delegate.

Description	Control Process to be Followed
External Legal Service Fees	Legal Services are arranged and approved by the CEO or CFO or designate
Licenses fees (i.e. regular license fees for vehicles, elevators, communications, software maintenance fees etc. required to maintain existing products and systems originally obtained in accordance with applicable policies and procedures)	License fees are to be approved by the appropriate SLT member or delegate
Payroll deduction/Union dues remittances	Remittances are approved by the appropriate Business Unit Lead.
Police Services	Payment for Police Services reviewed and approved by the Business Unit Lead
Postages/Office Supplies	Payments will be approved by the applicable Business Unit Lead
Regulatory Costs	Regulatory Costs are reviewed and approved by the Regulatory Department and Finance Lead
Refundable employee expenses (advances, meal allowances, travel, miscellaneous)	Refundable employee expenses are approved in by the Business unit based on applicable Milton Policy or Procedure
Real Estate Transactions	The CFO will review all recommended transactions with final authorization given by the President and CEO within limits of the Corporate Expenditure Authorization Policy.
Right of way or easements	Invoices are to be signed by the appropriate Business Unit Lead and the corresponding SLT team member in accordance with the Corporate Expenditure Authorization Policy
Telephone/Utilities	Invoices are reviewed by the appropriate Manager and are approved in accordance with the Corporate Expenditure Authorization Policy
Training	Invoices are approved by the Business Unit Lead in accordance with the Corporate Expenditure Authorization Policy
Workers Safety Insurance Board payments	Invoices are approved by Health and Safety Business Unit Lead in accordance with the Corporate Expenditure Authorization Policy

Appendix C

Competitive Procurement Exemptions

The following goods and services may be deemed a Complex Procurement and require a contract; however, they are exempt from meeting competitive procurement requirements as outlined in the bid solicitation guidelines:

1. Goods and services the supply of which is controlled by a statutory monopoly (i.e., toll highways)
2. Work to be performed on property under the provisions of a lease, warranty or guarantee held in respect of the property or the original work
3. The following goods and services related to training and education:
    - Conferences, conventions, courses, and seminars
    - Newspapers, magazines, books, and periodicals
    - Memberships
    - Computer software for educational purposes
4. The following special services:
    - Services of financial analysts or the management of investments by organizations who have such functions as a primary purpose
    - Financial services respecting the management of financial assets and liabilities (i.e., treasury operations), including ancillary advisory and information services, whether or not delivered by a financial institution
    - Health services and social services
    - Recreation and Wellness program facilitators and/or hosts
    - Expert witnesses
    - Arbitrators
    - Entertainers for theatre or special events
    - Utilities (water, hydro, natural gas, telecommunications, and cable television)
5. The payment of general expenses, such as:
    - Refundable employee expenses (advances, meal allowances, travel, miscellaneous)
    - Payroll deduction remittances
    - Workers Safety Insurance Board payments
    - Health benefits
    - Tax remittances
    - Payments to Shareholders
    - Debenture payments

- Insurance premiums
- Legal settlements
- Arbitration awards
- Petty cash replenishment
- Charges to and from other government bodies
- Honorariums
- Grants and Sponsorships (Corporate Responsibilities)
- Refunds (for cancelled services, programs, or events)
- Licenses fees (regular license fees for vehicles, elevators, communications, software, etc. required to maintain existing products and systems originally obtained in accordance with applicable policies and procedures)

APPENDIX D – PROCUREMENT SOLE OR SINGLE SOURCE APPROVAL FORM

Requestors are required to complete this form, forward to applicable business unit leadership for approval. The final approved document should be forwarded to Purchasing Supervisor, in order to commence with the procurement of the goods and or services. The supplier must not be engaged until these steps have been completed. This form does not replace a Purchase Order or any previously established Purchasing Policy.

Requesting Department:	
Requestor:	
Date:	

Project Name:	
Description of the Good or Service:	
Legal Services involved:	☐ Yes ☐ No
Recommended Supplier Name:	
Estimated Total Procurement Value: **Yearly:** **Total Contract Value:**	$ $ $
Multi-year commitment, if yes how many years:	☐ Yes ☐ No #
Is the Project In/Out of Budget:	☐ In ☐ Out

Select the reason(s) that apply for the Sole/Single Source Request:

☐	A standard procurement process conducted in accordance with applicable policies and procedures has not resulted in the receipt of any bids.
☐	Where the required goods or services can only be supplied by one particular supplier, and no alternative or substitute exists, or is currently available that meets the specific requirements of the acquisition.
☐	To ensure compatibility with existing products.
☐	To recognize exclusive rights, such as exclusive licenses, copyright and patent rights.
☐	To maintain specialized products that must be maintained by the manufacturer or its representative.
☐	The goods can be purchased under exceptionally advantageous circumstances such as bankruptcy or receivership.
☐	The procurement is for a prototype to be developed in the course of and for a particular contract for research, experiment, study or original development.
☐	Only one supplier or distributor indicated its availability demographically to meet the requirements and timelines for this acquisition and the Department is not able to alter the requirements or extend the timelines to allow for competition.
☐	Confidential and or strategically sensitive engagements or acquisitions.

☐	Where an unforeseeable situation of urgency exists and competitive methods of purchasing would result in Milton Hydro's inability to obtain the Deliverable in time.
☐	Where Deliverables relating to matters of a confidential or privileged nature are required and disclosure of these matters could reasonably be expected to compromise confidentiality, cause economic disruption, or otherwise be contrary to the public interest.
☐	Other reasons not listed above:

Insert details and business case to explain and support the identified reason(s), total cost of ownership, and attach any relevant documentation.

All signatures must be obtained prior to proceeding with any procurement. A copy of approved requests will be returned to the Requestor to keep on file for auditing purposes.

Requestor:		**Signature:**		**Date:**	
Business Unit Leadership Approved **		**Signature:**		**Date:**	
Purchasing Supervisor:		**Signature:**		**Date:**	

** Based on dollar value and Corporate Expenditure Authorization policy levels

EXHIBIT 4

ATTACHMENT 4-7

CORPORATE EXPENDITURE AUTHORIZATION POLICY

MILTON HYDRO

POLICY

Corp-02: Corporate Expenditure Authorization Policy

Document Owner	Milton Inc.	
Policy Owner	Corporate Finance	
Reviewed by	Senior Management Team	August 3, 2021
Approved by	Board of Directors	August 30, 2021
Document Distribution	Policy Binder, Intranet	
This policy is for internal use only		

Note: The most up-to-date versions of all policies are posted on the Intranet under Policies & Procedures. Printed copies should not be relied upon to be the most current version.

1. APPLICATION

1.1 This Policy applies to Milton ("Company"), its subsidiaries and all of their employees, subject to any applicable Collective Agreement requirements.

2. PURPOSE

2.1 This Policy sets out the corporate expenditure authorization levels that have been delegated to specified members of management. These authorizations apply to purchase requisitions, invoice approvals, execution of contract and any other process or practice by which the Company can be committed to expenditure of monies.

2.2 Each expenditure, regardless of who is approving it, must have a legitimate business purpose, be reasonable in nature and amount, and be approved in accordance with all Company policies and practices.

2.3 The Policy also sets out requirements relating to (i) to segregate the ordering, authorization and payment functions, (ii) authorization of the payment of taxes and interest, and (iii) execution of contracts.

3. POLICY STATEMENT

3.1 Management Authorization Limits

The authorization limits are set out in Schedule A attached hereto. Authorizations even within the specified limits in Schedule A are subject to the other terms of this Policy as delegated by the Board of Directors. Management is required to ensure that any authorization does not transgress this policy prior to authorization.

In determining whether an approval falls within the limit amounts specified in Schedule A, the calculation shall include any and all payments which could potentially be payable including contingent payments;

and in the case of a contract, any and all amounts which may be paid in respect of all renewal terms specified in the contract. Harmonized Sales Tax shall be excluded from the calculation.

The authorities set out in Schedule A will form the basis for further delegation, as required, to other staff. This will be used as a basis for the cascading of authorities by each organizational unit down to its staff. Delegation of approval to staff with a lower signing authority level must be documented, outlining their signing authority limits and applicable dates for the delegation in effect.

Temporary or contract staff are permitted to authorize expenditures according to Schedule A, on the basis they report directly to a full-time management staff member and are included in the Company's headcount.

Approval requires the authorizer's printed name and signature. Initials are not acceptable approval. Electronic approval, submitted via any Enterprise System, containing the authorizer's name is acceptable.

3.2 Other Requirements

3.2.1 Segregation of Ordering, Authorization and Payment Functions:

a) The individual ordering an item may not approve the related purchase for payment;

b) The individual responsible for processing payments may not order or approve the purchases for such payments;

c) Under no circumstances shall the value of a transaction be split into smaller segments for the purpose of avoiding the authorization limits; and

d) No one, at any level, may approve their own orders or expenditures. The person to whom an individual reports will approve all orders or expenditures initiated by an individual, and the Board shall approve orders or expenditures for the CEO. In the interest of timeliness, the CFO may review and authorize orders and expenditures initiated by the CEO for subsequent authorization by the Board but only where such orders and expenditures are within the CEO Authority Limits.

3.2.2 Special Items – Exceptions

In order to achieve efficient payment practices and avoid applicable late fees, some transactions as listed in Schedule B are considered Authorized Exceptions and can be approved by the Authorized Approver. The actual payment is approved by the signing officers.

3.2.3 Contractual Commitments

All contracts must be reviewed, authorized, and signed by an individual holding an office described in

Schedule A and in each case shall be subject to the limits set forth in Schedule A.

All contracts shall be reviewed by the Company's external legal counsel except where the contract is prepared based on a precedent contract previously approved by internal or external legal counsel and the only changes being made to that precedent are to names, dates or other matters which have been expressly specified in the precedent contract as acceptable insertions and the value of the contract is less than $250,000.

The individual signing the contract is responsible to ensure the form of contract and its execution complies fully with this Policy.

3.2.4 Board Approval

Board approval is required when the expenditures exceed the authorization limits set out in Schedule A.

3.3 Small Differences from Authorized Purchase Order

Invoices that exceed the authorized Purchase Order value by: (i) less than $50; or (ii) greater than $50 up to 10% of the value of the Purchase Order to a maximum of $1,000 may be processed in normal course by Accounts Payable. Such invoice exceptions must be approved in accordance with the applicable work procedure.

Notwithstanding the above, under no circumstance should an invoice exception of any amount be processed for: (i) an inventory or non-inventory part number; or (ii) freight cost variances where freight is intended to be at the expense of the supplier.

4. RELATED WORK PROCEDURES AND WORKINSTRUCTIONS

[To be finalized when Milton policies are finalized.]

5. FORMS AND RELATED DOCUMENTS

Corp-01: Corporate Purchasing Policy

MILTON HYDRO

SCHEDULE A: Authorizations Limits

Position	**Authorization Limit (Budgeted Expenditures**	**Authorization Limit (Non-Budget Expenditures)***	**Special Conditions****
CEO	$1,000,000	$250,000	Authority to manage line items within the budget envelope
CFO	$100,000	$50,000	
Director	$50,000	$10,000	
Manager	$10,000	$0	
Supervisor	$5,000	$0	
Executive Assistant	$2,000	$0	

* Any non-budgeted expenditure must fall within matters for which the authorizing individual has direct or indirect responsibility

** In addition to any other special conditions described here, in each case the authorization does not extend to authorizing expenditures for matters which, under the Policy, require Board or CEO authorization.

MILTON HYDRO

SCHEDULE B: Authorization Exceptions to Approvals for Budgeted Expenditures

Type of Expense	Payee	Approximate Maximum Value of Payment	Authorized Approver
Power Bill Power Bill	IESO Hydro One	TBD	CFO
Payroll Related Remittances	Canada Revenue Agency; Ministry of Revenue; Minister of Finance; WSIB; OMERS; Group Benefits Provider(s)	Various	CFO, Controller
Water & Waste Water Amounts Collected on Behalf of Municipalities	Region of Halton	Various	CFO
Debt Retirement Charge	Ministry of Revenue OEFC	TBD	CFO
PILs Payments	Ministry of Revenue	Various	CFO
HST Remittances	Canada Revenue Agency	TBD	CFO
Inter-company settlements		Various	CFO, Director, Manager
Lease agreements		Various	CFO
Insurance contracts		Various	CFO
Asset write-offs and/ or provisions, including AFDA and provision for obsolete inventory		Various	CFO

EXHIBIT 4

ATTACHMENT 4-8

OEB APPENDIX 2-C FOR 2016-2023

Appendix 2-C

Depreciation and Amortization Expense - 2016

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated 7	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated 8	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1609	Capital Contributions Paid	$ 114,707		$ 114,707			$ -		37.50	2.67%	40.00	2.50%	$ 3,059	$ -	$ -	$ 3,059	$ 3,059	$ 0
1611	Computer Software (Formally known as Account 1925)	$ 440,771		$ 440,771			$ -	$ 330,483	2.79	35.84%	5.00	20.00%	$ 157,982	$ -	$ 33,048	$ 191,031	$ 191,003	-$ 28
1612	Land Rights (Formally known as Account 1906)			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 69,883		$ 69,883			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 43,417		$ 43,417			$ -		2.84	35.21%	30.00	3.33%	$ 15,288	$ -	$ -	$ 15,288	$ 15,275	-$ 13
1825	Storage Battery Equipment			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 21,120,953		$ 21,120,953			$ -	$ 1,648,808	38.10	2.62%	45.00	2.22%	$ 554,356	$ -	$ 18,320	$ 572,676	$ 572,680	$ 4
1835	Overhead Conductors & Devices	$ 10,737,189		$ 10,737,189			$ -	$ 837,639	36.27	2.76%	45.00	2.22%	$ 296,035	$ -	$ 9,307	$ 305,342	$ 305,344	$ 2
1840	Underground Conduit	$ 17,556,609		$ 17,556,609			$ -	$ 1,598,185	30.55	3.27%	40.00	2.50%	$ 574,684	$ -	$ 19,977	$ 594,662	$ 594,670	$ 8
1845	Underground Conductors & Devices	$ 12,125,853		$ 12,125,853			$ -	$ 1,314,963	33.07	3.02%	40.00	2.50%	$ 366,672	$ -	$ 16,437	$ 383,109	$ 383,063	-$ 46
1850	Line Transformers	$ 21,903,085		$ 21,903,085			$ -	$ 1,940,950	30.12	3.32%	40.00	2.50%	$ 727,194	$ -	$ 24,262	$ 751,456	$ 751,400	-$ 56
1855	Services (Overhead & Underground)	$ 9,002,509		$ 9,002,509			$ -	$ 743,376	34.18	2.93%	40.00	2.50%	$ 263,385	$ -	$ 9,292	$ 272,677	$ 272,684	$ 7
1860	Meters			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 5,850,482		$ 5,850,482			$ -	$ 792,384	6.74	14.84%	15.00	6.67%	$ 868,024	$ -	$ 26,413	$ 894,437	$ 894,650	$ 213
1905	Land	$ 4,040,000		$ 4,040,000			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 8,854,219		$ 8,854,219			$ -	$ 1,299,480	49.50	2.02%	50.00	2.00%	$ 178,873	$ -	$ 12,995	$ 191,868	$ 178,873	-$ 12,995
1908	Buidling disallowed in 2016 COS	-$ 1,414,910		-$ 1,414,910			$ -		49.50	2.02%	50.00	2.00%	-$ 28,584	$ -	$ -	-$ 28,584	-$ 28,584	$ 0
1910	Leasehold Improvements			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 357,262		$ 357,262			$ -	$ 66,356	7.35	13.61%	10.00	10.00%	$ 48,607	$ -	$ 3,318	$ 51,925	$ 51,923	-$ 2
1915	Office Furniture & Equipment (5 years)			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 309,831		$ 309,831			$ -	$ 80,109	3.07	32.55%	5.00	20.00%	$ 100,856	$ -	$ 8,011	$ 108,867	$ 108,879	$ 12
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,461,807		$ 1,461,807			$ -	$ 480,681	8.31	12.03%	10.50	9.52%	$ 175,909	$ -	$ 22,890	$ 198,799	$ 199,155	$ 356
1935	Stores Equipment	$ 320,182		$ 320,182			$ -	$ 7,460	16.17	6.18%	12.00	8.33%	$ 19,801	$ -	$ 311	$ 20,112	$ 20,108	-$ 4
1940	Tools, Shop & Garage Equipment	$ 61,684		$ 61,684			$ -	$ 25,577	3.34	29.94%	10.00	10.00%	$ 18,468	$ -	$ 1,279	$ 19,747	$ 19,725	-$ 22
1945	Measurement & Testing Equipment	$ 49,393		$ 49,393			$ -			0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1950	Power Operated Equipment			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 344,204		$ 344,204			$ -	$ 79,731	9.16	10.92%	10.00	10.00%	$ 37,577	$ -	$ 3,987	$ 41,563	$ 41,573	$ 10
1955	Communication Equipment (Smart Meters)			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 75,608		$ 75,608			$ -	$ 74,692	13.00	7.69%	15.00	6.67%	$ 5,816	$ -	$ 2,490	$ 8,306	$ 8,317	$ 11
1985	Miscellaneous Fixed Assets			$ -			$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ 72,697		$ 72,697			$ -		5.02	19.92%	10.00	10.00%	$ 14,481	$ -	$ -	$ 14,481	$ 14,468	-$ 13
1995	Contributions & Grants	-$ 32,897,303		-$ 32,897,303			$ -		29.73	3.36%		0.00%	-$ 1,106,536	$ -	$ -	-$ 1,106,536	-$ 1,106,498	$ 38
2440	Deferred Revenue	-$ 6,481,515		-$ 6,481,515			$ -	-$ 3,333,020	37.57	2.66%	40.00	2.50%	-$ 172,518	$ -	-$ 41,663	-$ 214,181	-$ 214,162	$ 19
	Total	**$ 74,118,617**	**$ -**	**$ 74,118,617**	**$ -**	**$ -**	**$ -**	**$ 7,987,854**					**$ 3,119,431**	**$ -**	**$ 170,673**	**$ 3,290,104**	**$ 3,277,605**	**-$ 12,499**

Appendix 2-C

Depreciation and Amortization Expense - 2017

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated 7	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated 8	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1609	Capital Contributions Paid	$ 114,707		$ 114,707	$ -		$ -		37.50	2.67%	40.00	2.50%	$ 3,059	$ -	$ -	$ 3,059	$ 3,059	$ 0
1611	Computer Software (Formally known as Account 1925)	$ 440,771	$ 3,756	$ 437,015	$ 330,483		$ 330,483	$ 487,432	3.24	30.86%	5.00	20.00%	$ 134,881	$ 66,097	$ 48,743	$ 249,721	$ 249,705	-$ 16
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 69,883		$ 69,883	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 43,417	$ 4,079	$ 39,338	$ -		$ -		3.51	28.49%	30.00	3.33%	$ 11,207	$ -	$ -	$ 11,207	$ 11,196	-$ 11
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 21,120,953	$ 105,732	$ 21,015,221	$ 1,648,808		$ 1,648,808	$ 1,061,004	38.16	2.62%	45.00	2.22%	$ 550,713	$ 36,640	$ 11,789	$ 599,142	$ 599,157	$ 15
1835	Overhead Conductors & Devices	$ 10,737,189	$ 12,389	$ 10,724,800	$ 837,639		$ 837,639	$ 827,424	36.68	2.73%	45.00	2.22%	$ 292,388	$ 18,614	$ 9,194	$ 320,196	$ 320,218	$ 22
1840	Underground Conduit	$ 17,556,609		$ 17,556,609	$ 1,598,185		$ 1,598,185	$ 1,182,959	30.47	3.28%	40.00	2.50%	$ 576,193	$ 39,955	$ 14,787	$ 630,935	$ 631,006	$ 71
1845	Underground Conductors & Devices	$ 12,125,853	$ 23,106	$ 12,102,747	$ 1,314,963		$ 1,314,963	$ 950,594	32.88	3.04%	40.00	2.50%	$ 368,088	$ 32,874	$ 11,882	$ 412,845	$ 412,848	$ 3
1850	Line Transformers	$ 21,903,085	$ 128,825	$ 21,774,260	$ 1,940,950		$ 1,940,950	$ 1,598,855	30.28	3.30%	40.00	2.50%	$ 719,097	$ 48,524	$ 19,986	$ 787,607	$ 787,707	$ 100
1855	Services (Overhead & Underground)	$ 9,002,509		$ 9,002,509	$ 743,376		$ 743,376	$ 646,435	34.01	2.94%	40.00	2.50%	$ 264,702	$ 18,584	$ 8,080	$ 291,367	$ 291,401	$ 34
1860	Meters	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 5,850,482	$ 117,949	$ 5,732,533	$ 792,384		$ 792,384	$ 1,031,568	8.28	12.08%	15.00	6.67%	$ 692,335	$ 52,826	$ 34,386	$ 779,546	$ 779,471	-$ 75
1905	Land	$ 4,040,000		$ 4,040,000	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 8,854,219		$ 8,854,219	$ 1,299,480		$ 1,299,480	$ 74,555	49.50	2.02%	50.00	2.00%	$ 178,873	$ 25,990	$ 746	$ 205,608	$ 207,204	$ 1,596
1908	Buidling disallowed in 2016 COS	-$ 1,414,910		-$ 1,414,910	$ -		$ -		49.50	2.02%	50.00	2.00%	-$ 28,584	$ -	$ -	-$ 28,584	-$ 28,584	$ 0
1910	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 357,262	$ 1,097	$ 356,165	$ 66,356		$ 66,356	$ 5,773	7.41	13.50%	10.00	10.00%	$ 48,065	$ 6,636	$ 289	$ 54,990	$ 54,981	-$ 9
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 309,831	$ 5,304	$ 304,527	$ 80,109		$ 80,109	$ 70,635	3.39	29.50%	5.00	20.00%	$ 89,831	$ 16,022	$ 7,064	$ 112,916	$ 112,986	$ 70
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,461,807		$ 1,461,807	$ 480,681		$ 480,681	$ 117,645	8.30	12.05%	10.00	10.00%	$ 176,121	$ 48,068	$ 5,882	$ 230,072	$ 230,038	-$ 34
1935	Stores Equipment	$ 320,182		$ 320,182	$ 7,460		$ 7,460	$ 6,000	16.17	6.18%	12.00	8.33%	$ 19,801	$ 622	$ 250	$ 20,673	$ 20,669	-$ 4
1940	Tools, Shop & Garage Equipment	$ 61,684	$ 933	$ 60,751	$ 25,577		$ 25,577	$ 30,928	9.08	11.01%	10.00	10.00%	$ 6,691	$ 2,558	$ 1,546	$ 10,795	$ 10,793	-$ 2
1945	Measurement & Testing Equipment	$ 49,393		$ 49,393	$ -		$ -		4.56	21.93%	10.00	10.00%	$ 10,832	$ -	$ -	$ 10,832	$ 10,824	-$ 8
1950	Power Operated Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 344,204	$ 335	$ 343,869	$ 79,731		$ 79,731	$ 13,232	9.05	11.05%	10.00	10.00%	$ 37,997	$ 7,973	$ 662	$ 46,631	$ 46,617	-$ 14
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 75,608		$ 75,608	$ 74,692		$ 74,692	$ 819,075	6.02	16.61%	15.00	6.67%	$ 12,559	$ 4,979	$ 27,303	$ 44,841	$ 44,847	$ 6
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ 72,697		$ 72,697	$ -		$ -		5.02	19.92%	10.00	10.00%	$ 14,481	$ -	$ -	$ 14,481	$ 14,468	-$ 13
1995	Contributions & Grants	-$ 32,897,303		-$ 32,897,303	$ -		$ -		29.75	3.36%	40.00	2.50%	-$ 1,105,792	$ -	$ -	-$ 1,105,792	-$ 1,105,481	$ 311
2440	Deferred Revenue	-$ 6,481,515		-$ 6,481,515	-$ 3,333,020		-$ 3,333,020	-$ 2,879,515	36.85	2.71%	40.00	2.50%	-$ 175,889	-$ 83,326	-$ 35,994	-$ 295,209	-$ 295,202	$ 7
	Total	**$ 74,118,617**	**$ 403,505**	**$ 73,715,112**	**$ 7,987,854**	**$ -**	**$ 7,987,854**	**$ 6,044,599**					**$ 2,897,651**	**$ 343,635**	**$ 166,593**	**$ 3,407,880**	**$ 3,409,928**	**$ 2,048**

Appendix 2-C

Depreciation and Amortization Expense - 2018

Account	Description	Book Values							Service Lives				Depreciation Expense					
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated 7	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated 8	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1609	Capital Contributions Paid	$ 114,707		$ 114,707	$ -		$ -		37.50	2.67%	40.00	2.50%	$ 3,059	$ -	$ -	$ 3,059	$ 3,059	$ 0
1611	Computer Software (Formally known as Account 1925)	$ 440,771	$ 81,307	$ 359,464	$ 817,915		$ 817,915	$ 550,748	4.26	23.47%	5.00	20.00%	$ 84,381	$ 163,583	$ 55,075	$ 303,039	$ 302,989	-$ 50
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 69,883		$ 69,883	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 43,417	$ 8,776	$ 34,641	$ -		$ -	$ 980	3.19	31.35%	30.00	3.33%	$ 10,859	$ -	$ 16	$ 10,876	$ 10,887	$ 11
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 21,120,953	$ 105,732	$ 21,015,221	$ 2,709,812		$ 2,709,812	$ 1,678,286	38.25	2.61%	45.00	2.22%	$ 549,418	$ 60,218	$ 18,648	$ 628,283	$ 628,353	$ 70
1835	Overhead Conductors & Devices	$ 10,737,189	$ 12,389	$ 10,724,800	$ 1,665,063		$ 1,665,063	$ 1,008,942	36.75	2.72%	45.00	2.22%	$ 291,831	$ 37,001	$ 11,210	$ 340,043	$ 340,070	$ 27
1840	Underground Conduit	$ 17,556,609		$ 17,556,609	$ 2,781,144		$ 2,781,144	$ 1,480,577	30.65	3.26%	40.00	2.50%	$ 572,809	$ 69,529	$ 18,507	$ 660,845	$ 660,886	$ 41
1845	Underground Conductors & Devices	$ 12,125,853	$ 23,106	$ 12,102,747	$ 2,265,557		$ 2,265,557	$ 887,635	33.12	3.02%	40.00	2.50%	$ 365,421	$ 56,639	$ 11,095	$ 433,155	$ 433,167	$ 12
1850	Line Transformers	$ 21,903,085	$ 128,825	$ 21,774,260	$ 3,539,805		$ 3,539,805	$ 2,149,076	30.62	3.27%	40.00	2.50%	$ 711,112	$ 88,495	$ 26,863	$ 826,471	$ 826,576	$ 105
1855	Services (Overhead & Underground)	$ 9,002,509		$ 9,002,509	$ 1,389,811		$ 1,389,811	$ 845,519	34.40	2.91%	40.00	2.50%	$ 261,701	$ 34,745	$ 10,569	$ 307,015	$ 306,995	-$ 20
1860	Meters	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 5,850,482	$ 392,429	$ 5,458,053	$ 1,823,952		$ 1,823,952	$ 1,486,195	8.28	12.08%	15.00	6.67%	$ 659,185	$ 121,597	$ 49,540	$ 830,322	$ 830,170	-$ 152
1905	Land	$ 4,040,000		$ 4,040,000	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 8,854,219		$ 8,854,219	$ 1,374,035		$ 1,374,035	$ 55,832	49.50	2.02%	50.00	2.00%	$ 178,873	$ 27,481	$ 558	$ 206,912	$ 207,304	$ 392
1908	Buidling disallowed in 2016 COS	-$ 1,414,910		-$ 1,414,910	$ -		$ -		49.50	2.02%	50.00	2.00%	-$ 28,584	$ -	$ -	-$ 28,584	-$ 28,584	$ 0
1910	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 357,262	$ 5,313	$ 351,949	$ 72,129		$ 72,129	$ 6,682	7.76	12.89%	10.00	10.00%	$ 45,354	$ 7,213	$ 334	$ 52,901	$ 52,889	-$ 12
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 309,831	$ 22,293	$ 287,538	$ 150,744		$ 150,744	$ 81,671	4.27	23.42%	5.00	20.00%	$ 67,339	$ 30,149	$ 8,167	$ 105,655	$ 105,695	$ 40
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,461,807		$ 1,461,807	$ 598,326		$ 598,326	$ 459,485	8.53	11.72%	10.00	10.00%	$ 171,372	$ 59,833	$ 22,974	$ 254,179	$ 254,123	-$ 56
1935	Stores Equipment	$ 320,182		$ 320,182	$ 13,460		$ 13,460	$ 8,476	16.17	6.18%	12.00	8.33%	$ 19,801	$ 1,122	$ 353	$ 21,276	$ 21,272	-$ 4
1940	Tools, Shop & Garage Equipment	$ 61,684	$ 933	$ 60,751	$ 56,505		$ 56,505	$ 143,258	9.08	11.01%	10.00	10.00%	$ 6,691	$ 5,651	$ 7,163	$ 19,504	$ 19,121	-$ 383
1945	Measurement & Testing Equipment	$ 49,393	$ 912	$ 48,481	$ -		$ -	$ 43,455	4.56	21.93%	10.00	10.00%	$ 10,632	$ -	$ 2,173	$ 12,805	$ 12,541	-$ 264
1950	Power Operated Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 344,204	$ 559	$ 343,645	$ 92,963		$ 92,963		9.05	11.05%	10.00	10.00%	$ 37,972	$ 9,296	$ -	$ 47,268	$ 46,505	-$ 763
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 75,608		$ 75,608	$ 893,767		$ 893,767	$ 337,550	12.90	7.75%	15.00	6.67%	$ 5,861	$ 59,584	$ 11,252	$ 76,697	$ 75,940	-$ 757
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ 72,697		$ 72,697	$ -		$ -		5.02	19.92%	10.00	10.00%	$ 14,481	$ -	$ -	$ 14,481	$ 14,468	-$ 13
1995	Contributions & Grants	-$ 32,897,303		-$ 32,897,303	$ -		$ -		29.75	3.36%	40.00	2.50%	-$ 1,105,792	$ -	$ -	-$ 1,105,792	-$ 1,105,235	$ 557
2440	Deferred Revenue	-$ 6,481,515		-$ 6,481,515	-$ 6,212,535		-$ 6,212,535	-$ 2,920,318	36.85	2.71%	40.00	2.50%	-$ 175,889	-$ 155,313	-$ 36,504	-$ 367,706	-$ 368,975	-$ 1,269
	Total	**$ 74,118,617**	**$ 782,574**	**$ 73,336,043**	**$ 14,032,453**	**$ -**	**$ 14,032,453**	**$ 8,304,049**					**$ 2,757,889**	**$ 676,822**	**$ 217,994**	**$ 3,652,705**	**$ 3,650,216**	**-$ 2,489**

Appendix 2-C

Depreciation and Amortization Expense -2019

Account	Description	Book Values							Service Lives				Depreciation Expense					
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated 7	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated 8	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1609	Capital Contributions Paid	$ 114,707		$ 114,707	$ -		$ -	$ 1,964,992	37.50	2.67%	40.00	2.50%	$ 3,059	$ -	$ 24,562	$ 27,621	$ 27,621	-$ 0
1611	Computer Software (Formally known as Account 1925)	$ 440,771	$ 172,933	$ 267,838	$ 1,368,663		$ 1,368,663	$ 207,348	4.07	24.57%	5.00	20.00%	$ 65,808	$ 273,733	$ 20,735	$ 360,275	$ 360,286	$ 11
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 69,883		$ 69,883	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 43,417	$ 34,108	$ 9,309	$ 980		$ 980		3.51	28.49%	30.00	3.33%	$ 2,652	$ 33	$ -	$ 2,685	$ 2,492	-$ 193
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 21,120,953	$ 105,732	$ 21,015,221	$ 4,388,098		$ 4,388,098	$ 953,574	38.56	2.59%	45.00	2.22%	$ 545,001	$ 97,513	$ 10,595	$ 653,109	$ 653,147	$ 38
1835	Overhead Conductors & Devices	$ 10,737,189	$ 12,389	$ 10,724,800	$ 2,674,005		$ 2,674,005	$ 836,727	31.40	3.18%	45.00	2.22%	$ 341,554	$ 59,422	$ 9,297	$ 410,273	$ 410,189	-$ 84
1840	Underground Conduit	$ 17,556,609		$ 17,556,609	$ 4,261,721		$ 4,261,721	$ 1,909,353	30.50	3.28%	40.00	2.50%	$ 575,627	$ 106,543	$ 23,867	$ 706,036	$ 706,008	-$ 28
1845	Underground Conductors & Devices	$ 12,125,853	$ 23,106	$ 12,102,747	$ 3,153,192		$ 3,153,192	$ 1,261,979	32.58	3.07%	40.00	2.50%	$ 371,478	$ 78,830	$ 15,775	$ 466,082	$ 466,044	-$ 38
1850	Line Transformers	$ 21,903,085	$ 147,991	$ 21,755,094	$ 5,688,881		$ 5,688,881	$ 1,593,486	33.96	2.94%	40.00	2.50%	$ 640,609	$ 142,222	$ 19,919	$ 802,750	$ 802,673	-$ 77
1855	Services (Overhead & Underground)	$ 9,002,509		$ 9,002,509	$ 2,235,330		$ 2,235,330	$ 587,882	34.01	2.94%	40.00	2.50%	$ 264,702	$ 55,883	$ 7,349	$ 327,934	$ 327,991	$ 57
1860	Meters	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 5,850,482	$ 577,292	$ 5,273,190	$ 3,310,147		$ 3,310,147	$ 1,215,553	8.33	12.00%	15.00	6.67%	$ 633,036	$ 220,676	$ 40,518	$ 894,231	$ 894,093	-$ 138
1905	Land	$ 4,040,000		$ 4,040,000	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 8,854,219		$ 8,854,219	$ 1,429,867		$ 1,429,867	$ 364,220	49.50	2.02%	50.00	2.00%	$ 178,873	$ 28,597	$ 3,642	$ 211,113	$ 216,235	$ 5,122
1908	Buidling disallowed in 2016 COS	-$ 1,414,910		-$ 1,414,910	$ -		$ -		49.50	2.02%	50.00	2.00%	-$ 28,584	$ -	$ -	-$ 28,584	-$ 28,584	$ 0
1910	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 357,262	$ 13,827	$ 343,435	$ 78,811		$ 78,811		8.08	12.38%	10.00	10.00%	$ 42,504	$ 7,881	$ -	$ 50,385	$ 50,385	-$ 0
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 309,831	$ 106,583	$ 203,248	$ 232,415		$ 232,415	$ 106,498	5.00	20.00%	5.00	20.00%	$ 40,650	$ 46,483	$ 10,650	$ 97,782	$ 95,606	-$ 2,176
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,461,807	$ 28,495	$ 1,433,312	$ 1,057,811		$ 1,057,811	$ 134,104	9.10	10.99%	10.00	10.00%	$ 157,507	$ 105,781	$ 6,705	$ 269,993	$ 269,919	-$ 74
1935	Stores Equipment	$ 320,182		$ 320,182	$ 21,936		$ 21,936	$ 26,414	16.17	6.18%	12.00	8.33%	$ 19,801	$ 1,828	$ 1,101	$ 22,730	$ 22,726	-$ 4
1940	Tools, Shop & Garage Equipment	$ 61,684	$ 2,385	$ 59,299	$ 199,763		$ 199,763	$ 52,594	9.08	11.01%	10.00	10.00%	$ 6,531	$ 19,976	$ 2,630	$ 29,137	$ 28,430	-$ 707
1945	Measurement & Testing Equipment	$ 49,393	$ 2,622	$ 46,771	$ 43,455		$ 43,455	$ 826	4.56	21.93%	10.00	10.00%	$ 10,257	$ 4,346	$ 41	$ 14,644	$ 14,185	-$ 459
1950	Power Operated Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 344,204	$ 9,346	$ 334,858	$ 92,963		$ 92,963	$ 13,627	9.70	10.31%	10.00	10.00%	$ 34,521	$ 9,296	$ 681	$ 44,499	$ 44,262	-$ 237
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 75,608		$ 75,608	$ 1,231,317		$ 1,231,317	$ 536,793	6.22	16.08%	15.00	6.67%	$ 12,156	$ 82,088	$ 17,893	$ 112,137	$ 111,589	-$ 548
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ 72,697		$ 72,697	$ -		$ -		5.02	19.92%	10.00	10.00%	$ 14,481	$ -	$ -	$ 14,481	$ 14,468	-$ 13
1995	Contributions & Grants	-$ 32,897,303		-$ 32,897,303	$ -		$ -		29.75	3.36%	40.00	2.50%	-$ 1,105,792	$ -	$ -	-$ 1,105,792	-$ 1,105,133	$ 659
2440	Deferred Revenue	-$ 6,481,515		-$ 6,481,515	-$ 9,132,853		-$ 9,132,853	-$ 2,025,360	36.85	2.71%	40.00	2.50%	-$ 175,889	-$ 228,321	-$ 25,317	-$ 429,527	-$ 431,291	-$ 1,764
	Total	**$ 74,118,617**	**$ 1,236,809**	**$ 72,881,808**	**$ 22,336,502**	**$ -**	**$ 22,336,502**	**$ 9,740,610**					**$ 2,650,541**	**$ 1,112,811**	**$ 190,643**	**$ 3,953,995**	**$ 3,953,341**	**-$ 654**

Appendix 2-C

Depreciation and Amortization Expense - 2020

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated 7	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated 8	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1609	Capital Contributions Paid	$ 114,707		$ 114,707	$ 1,964,992		$ 1,964,992	$ 115,892	37.50	2.67%	40.00	2.50%	$ 3,059	$ 49,125	$ 1,449	$ 53,632	$ 55,118	$ 1,486
1611	Computer Software (Formally known as Account 1925)	$ 440,771	$ 272,608	$ 168,163	$ 1,576,011		$ 1,576,011	$ 70,826	4.07	24.57%	5.00	20.00%	$ 41,318	$ 315,202	$ 7,083	$ 363,602	$ 357,116	-$ 6,486
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 69,883		$ 69,883	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 43,417	$ 35,124	$ 8,293	$ 980		$ 980		3.51	28.49%	30.00	3.33%	$ 2,363	$ 33	$ -	$ 2,395	$ 2,222	-$ 173
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 21,120,953	$ 105,732	$ 21,015,221	$ 5,341,672		$ 5,341,672	$ 2,434,491	38.77	2.58%	45.00	2.22%	$ 542,049	$ 118,704	$ 27,050	$ 687,802	$ 687,777	-$ 25
1835	Overhead Conductors & Devices	$ 10,737,189	$ 12,389	$ 10,724,800	$ 3,510,732		$ 3,510,732	$ 1,913,635	33.68	2.97%	45.00	2.22%	$ 318,432	$ 78,016	$ 21,263	$ 417,711	$ 417,749	$ 38
1840	Underground Conduit	$ 17,556,609	$ 12,370	$ 17,544,239	$ 6,171,074		$ 6,171,074	$ 740,115	30.60	3.27%	40.00	2.50%	$ 573,341	$ 154,277	$ 9,251	$ 736,869	$ 736,830	-$ 39
1845	Underground Conductors & Devices	$ 12,125,853	$ 23,106	$ 12,102,747	$ 4,415,171		$ 4,415,171	$ 611,441	32.95	3.03%	40.00	2.50%	$ 367,306	$ 110,379	$ 7,643	$ 485,329	$ 485,384	$ 55
1850	Line Transformers	$ 21,903,085	$ 147,991	$ 21,755,094	$ 7,282,367		$ 7,282,367	$ 1,780,282	31.34	3.19%	40.00	2.50%	$ 694,164	$ 182,059	$ 22,254	$ 898,477	$ 898,507	$ 30
1855	Services (Overhead & Underground)	$ 9,002,509		$ 9,002,509	$ 2,823,212		$ 2,823,212	$ 373,374	34.07	2.94%	40.00	2.50%	$ 264,236	$ 70,580	$ 4,667	$ 339,483	$ 339,519	$ 36
1860	Meters	$ -		$ -	$ -		$ -			0.00%	40.00	2.50%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 5,850,482	$ 914,604	$ 4,935,878	$ 4,525,700		$ 4,525,700	$ 1,280,000	9.40	10.64%	15.00	6.67%	$ 525,093	$ 301,713	$ 42,667	$ 869,473	$ 869,290	-$ 183
1905	Land	$ 4,040,000		$ 4,040,000	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 8,854,219		$ 8,854,219	$ 1,794,087		$ 1,794,087	$ 30,135	49.50	2.02%	50.00	2.00%	$ 178,873	$ 35,882	$ 301	$ 215,056	$ 216,897	$ 1,841
1908	Buidling disallowed in 2016 COS	-$ 1,414,910		-$ 1,414,910	$ -		$ -		49.50	2.02%	50.00	2.00%	-$ 28,584	$ -	$ -	-$ 28,584	-$ 28,584	$ 0
1910	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 357,262	$ 13,827	$ 343,435	$ 78,811		$ 78,811	$ 2,685	8.08	12.38%	10.00	10.00%	$ 42,504	$ 7,881	$ 134	$ 50,520	$ 50,165	-$ 355
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 309,831	$ 190,927	$ 118,904	$ 338,913		$ 338,913	$ 83,786	5.00	20.00%	5.50	18.18%	$ 23,781	$ 61,621	$ 7,617	$ 93,018	$ 89,373	-$ 3,645
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,461,807	$ 59,869	$ 1,401,938	$ 1,191,915		$ 1,191,915		8.52	11.74%	10.90	9.17%	$ 164,547	$ 109,350	$ -	$ 273,897	$ 273,819	-$ 78
1935	Stores Equipment	$ 320,182		$ 320,182	$ 48,350		$ 48,350	$ 9,743	16.17	6.18%	12.00	8.33%	$ 19,801	$ 4,029	$ 406	$ 24,236	$ 24,233	-$ 3
1940	Tools, Shop & Garage Equipment	$ 61,684	$ 2,385	$ 59,299	$ 252,357		$ 252,357	$ 18,043	9.08	11.01%	10.00	10.00%	$ 6,531	$ 25,236	$ 902	$ 32,669	$ 31,837	-$ 832
1945	Measurement & Testing Equipment	$ 49,393	$ 2,622	$ 46,771	$ 44,281		$ 44,281		4.87	20.53%	10.00	10.00%	$ 9,604	$ 4,428	$ -	$ 14,032	$ 14,027	-$ 5
1950	Power Operated Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 344,204	$ 9,346	$ 334,858	$ 106,590		$ 106,590	$ 9,108	9.70	10.31%	10.00	10.00%	$ 34,521	$ 10,659	$ 455	$ 45,636	$ 45,493	-$ 143
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 75,608		$ 75,608	$ 1,768,110		$ 1,768,110	$ 232,323	9.90	10.10%	15.00	6.67%	$ 7,637	$ 117,874	$ 7,744	$ 133,255	$ 133,252	-$ 3
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ 72,697		$ 72,697	$ -		$ -		6.59	15.17%	10.00	10.00%	$ 11,031	$ -	$ -	$ 11,031	$ 11,029	-$ 2
1995	Contributions & Grants	-$ 32,897,303		-$ 32,897,303	$ -		$ -		29.75	3.36%		0.00%	-$ 1,105,792	$ -	$ -	-$ 1,105,792	-$ 1,105,078	$ 714
2440	Deferred Revenue	-$ 6,481,515		-$ 6,481,515	-$ 11,158,213		-$ 11,158,213	-$ 2,303,048	36.85	2.71%	40.00	2.50%	-$ 175,889	-$ 278,955	-$ 28,788	-$ 483,633	-$ 484,446	-$ 813
	Total	**$ 74,118,617**	**$ 1,802,900**	**$ 72,315,717**	**$ 32,077,112**	**$ -**	**$ 32,077,112**	**$ 7,402,831**					**$ 2,519,926**	**$ 1,478,093**	**$ 132,098**	**$ 4,130,117**	**$ 4,121,529**	**-$ 8,588**

Appendix 2-C

Depreciation and Amortization Expense - 2021

Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated 7	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated 8	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		Book Values							Service Lives				Depreciation Expense					
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1609	Capital Contributions Paid	$ 114,707		$ 114,707	$ 2,080,884		$ 2,080,884	-$ 194,227	37.50	2.67%	40.00	2.50%	$ 3,059	$ 52,022	-$ 2,428	$ 52,653	$ 50,073	-$ 2,580
1611	Computer Software (Formally known as Account 1925)	$ 440,771	$ 440,771	$ -	$ 1,646,837		$ 1,646,837	$ 69,824	-	0.00%	5.50	18.18%	$ -	$ 299,425	$ 6,348	$ 305,773	$ 294,969	-$ 10,804
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 69,883		$ 69,883	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 43,417	$ 41,564	$ 1,853	$ 980		$ 980		3.55	28.17%	30.00	3.33%	$ 522	$ 33	$ -	$ 555	$ 934	$ 379
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 21,120,953	$ 105,732	$ 21,015,221	$ 7,776,163		$ 7,776,163	$ 1,352,817	39.48	2.53%	45.00	2.22%	$ 532,300	$ 172,804	$ 15,031	$ 720,135	$ 720,071	-$ 64
1835	Overhead Conductors & Devices	$ 10,737,189	$ 12,389	$ 10,724,800	$ 5,424,367		$ 5,424,367	$ 776,302	33.73	2.96%	45.00	2.22%	$ 317,960	$ 120,541	$ 8,626	$ 447,127	$ 447,099	-$ 28
1840	Underground Conduit	$ 17,556,609	$ 13,776	$ 17,542,833	$ 6,911,189		$ 6,911,189	$ 1,551,133	30.75	3.25%	40.00	2.50%	$ 570,499	$ 172,780	$ 19,389	$ 762,668	$ 762,721	$ 53
1845	Underground Conductors & Devices	$ 12,125,853	$ 29,359	$ 12,096,494	$ 5,026,612		$ 5,026,612	$ 999,088	32.71	3.06%	40.00	2.50%	$ 369,810	$ 125,665	$ 12,489	$ 507,964	$ 507,926	-$ 38
1850	Line Transformers	$ 21,903,085	$ 147,991	$ 21,755,094	$ 9,062,649		$ 9,062,649	$ 1,862,645	31.65	3.16%	40.00	2.50%	$ 687,365	$ 226,566	$ 23,283	$ 937,214	$ 937,124	-$ 90
1855	Services (Overhead & Underground)	$ 9,002,509		$ 9,002,509	$ 3,196,586		$ 3,196,586	$ 727,844	34.12	2.93%	40.00	2.50%	$ 263,848	$ 79,915	$ 9,098	$ 352,861	$ 352,822	-$ 39
1860	Meters	$ -		$ -	$ -		$ -			0.00%	40.00	2.50%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 5,850,482	$ 1,141,924	$ 4,708,558	$ 5,805,700		$ 5,805,700	$ 1,172,186	10.14	9.86%	15.00	6.67%	$ 464,355	$ 387,047	$ 39,073	$ 890,474	$ 890,184	-$ 290
1905	Land	$ 4,040,000		$ 4,040,000	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 8,854,219		$ 8,854,219	$ 1,824,222		$ 1,824,222		49.50	2.02%	50.00	2.00%	$ 178,873	$ 36,484	$ -	$ 215,358	$ 216,897	$ 1,539
1908	Buidling disallowed in 2016 COS	-$ 1,414,910		-$ 1,414,910	$ -		$ -		49.50	2.02%	50.00	2.00%	-$ 28,584	$ -	$ -	-$ 28,584	-$ 28,584	$ 0
1910	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 357,262	$ 17,022	$ 340,240	$ 81,496		$ 81,496		8.97	11.15%	10.00	10.00%	$ 37,931	$ 8,150	$ -	$ 46,080	$ 46,056	-$ 24
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 309,831	$ 309,831	$ -	$ 422,699		$ 422,699	$ 92,147	-	0.00%	5.50	18.18%	$ -	$ 76,854	$ 8,377	$ 85,231	$ 85,744	$ 513
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,461,807	$ 166,809	$ 1,294,998	$ 1,191,915		$ 1,191,915	$ 68,707	8.98	11.14%	10.90	9.17%	$ 144,209	$ 109,350	$ 3,152	$ 256,711	$ 256,725	$ 14
1935	Stores Equipment	$ 320,182		$ 320,182	$ 58,093		$ 58,093		16.17	6.18%	12.00	8.33%	$ 19,801	$ 4,841	$ -	$ 24,642	$ 24,639	-$ 3
1940	Tools, Shop & Garage Equipment	$ 61,684	$ 3,512	$ 58,172	$ 270,400		$ 270,400	$ 39,554	10.87	9.20%	10.00	10.00%	$ 5,352	$ 27,040	$ 1,978	$ 34,369	$ 34,369	-$ 0
1945	Measurement & Testing Equipment	$ 49,393	$ 4,408	$ 44,985	$ 44,281		$ 44,281		6.78	14.75%	10.00	10.00%	$ 6,635	$ 4,428	$ -	$ 11,063	$ 11,064	$ 1
1950	Power Operated Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 344,204	$ 11,095	$ 333,109	$ 115,698		$ 115,698	$ 13,139	9.70	10.31%	10.00	10.00%	$ 34,341	$ 11,570	$ 657	$ 46,568	$ 45,429	-$ 1,139
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 75,608		$ 75,608	$ 2,000,433		$ 2,000,433	$ 259,425	12.90	7.75%	15.00	6.67%	$ 5,861	$ 133,362	$ 8,648	$ 147,871	$ 148,676	$ 805
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ 72,697	$ 30,949	$ 41,748	$ -		$ -		10.00	10.00%	10.00	10.00%	$ 4,175	$ -	$ -	$ 4,175	$ 3,795	-$ 380
1995	Contributions & Grants	-$ 32,897,303		-$ 32,897,303	$ -		$ -		29.88	3.35%		0.00%	-$ 1,100,981	$ -	$ -	-$ 1,100,981	-$ 1,101,129	-$ 148
2440	Deferred Revenue	-$ 6,481,515		-$ 6,481,515	-$ 13,461,261		-$ 13,461,261	-$ 2,947,234	36.85	2.71%	40.00	2.50%	-$ 175,889	-$ 336,532	-$ 36,840	-$ 549,261	-$ 548,596	$ 665
	Major Spare							$ 610,000		0.00%	40.00	2.50%	$ -	$ -	$ 7,625	$ 7,625	$ -	-$ 7,625
	Total	**$ 74,118,617**	**$ 2,477,132**	**$ 71,641,485**	**$ 39,479,943**	**$ -**	**$ 39,479,943**	**$ 6,453,350**					**$ 2,341,442**	**$ 1,712,345**	**$ 124,504**	**$ 4,178,292**	**$ 4,159,008**	**-$ 19,284**

Appendix 2-C

Depreciation and Amortization Expense - 2022

		Book Values							Service Lives				Depreciation Expense					
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated 7	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated 8	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1609	Capital Contributions Paid	$ 114,707		$ 114,707	$ 1,886,657		$ 1,886,657		37.50	2.67%	40.00	2.50%	$ 3,059	$ 47,166	$ -	$ 50,225	$ 50,073	-$ 152
1611	Computer Software (Formally known as Account 1925)	$ 440,771	$ 440,771	$ -	$ 1,716,661	$ 502,441	$ 1,214,220	$ 547,060		0.00%	5.50	18.18%	$ -	$ 220,767	$ 49,733	$ 270,500	$ 263,251	-$ 7,249
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 69,883		$ 69,883	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 43,417	$ 43,814	-$ 397	$ 980		$ 980		3.55	28.17%	30.00	3.33%	-$ 112	$ 33	$ -	-$ 79	$ 934	$ 1,013
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 21,120,953	$ 105,732	$ 21,015,221	$ 9,128,980		$ 9,128,980	$ 2,123,772	39.50	2.53%	45.00	2.22%	$ 532,031	$ 202,866	$ 23,597	$ 758,495	$ 758,391	-$ 104
1835	Overhead Conductors & Devices	$ 10,737,189	$ 12,389	$ 10,724,800	$ 6,200,669		$ 6,200,669	$ 1,959,548	33.63	2.97%	45.00	2.22%	$ 318,906	$ 137,793	$ 21,773	$ 478,471	$ 478,507	$ 36
1840	Underground Conduit	$ 17,556,609	$ 13,916	$ 17,542,693	$ 8,462,322		$ 8,462,322	$ 1,667,581	30.71	3.26%	40.00	2.50%	$ 571,237	$ 211,558	$ 20,845	$ 803,640	$ 803,552	-$ 88
1845	Underground Conductors & Devices	$ 12,125,853	$ 29,652	$ 12,096,201	$ 6,025,700		$ 6,025,700	$ 1,115,865	32.31	3.10%	40.00	2.50%	$ 374,379	$ 150,643	$ 13,948	$ 538,970	$ 539,020	$ 50
1850	Line Transformers	$ 21,903,085	$ 147,991	$ 21,755,094	$ 10,925,294		$ 10,925,294	$ 2,187,208	31.72	3.15%	40.00	2.50%	$ 685,848	$ 273,132	$ 27,340	$ 986,320	$ 986,386	$ 66
1855	Services (Overhead & Underground)	$ 9,002,509		$ 9,002,509	$ 3,924,430		$ 3,924,430	$ 776,762	34.16	2.93%	40.00	2.50%	$ 263,539	$ 98,111	$ 9,710	$ 371,360	$ 371,366	$ 6
1860	Meters	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 5,850,482	$ 1,737,838	$ 4,112,644	$ 6,977,886	$ 23,641	$ 6,954,245	$ 2,820,676	8.90	11.24%	15.00	6.67%	$ 462,095	$ 463,616	$ 94,023	$ 1,019,734	$ 1,019,722	-$ 12
1905	Land	$ 4,040,000		$ 4,040,000	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 8,854,219		$ 8,854,219	$ 1,824,222		$ 1,824,222	$ 593,000	49.50	2.02%	50.00	2.00%	$ 178,873	$ 36,484	$ 5,930	$ 221,288	$ 222,827	$ 1,539
1908	Buidling disallowed in 2016 COS			$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 357,262	$ 59,791	$ 297,471	$ 81,496		$ 81,496		8.74	11.44%	10.00	10.00%	$ 34,036	$ 8,150	$ -	$ 42,185	$ 42,168	-$ 17
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 309,831	$ 309,831	$ -	$ 514,846	$ 80,109	$ 434,737	$ 117,500		0.00%	5.50	18.18%	$ -	$ 79,043	$ 10,682	$ 89,725	$ 91,634	$ 1,909
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,461,807	$ 166,809	$ 1,294,998	$ 1,260,622		$ 1,260,622	$ 751,500	9.24	10.82%	10.90	9.17%	$ 140,151	$ 115,653	$ 34,472	$ 290,277	$ 290,228	-$ 49
1935	Stores Equipment	$ 320,182		$ 320,182	$ 58,093		$ 58,093	$ 20,000	16.17	6.18%	12.00	8.33%	$ 19,801	$ 4,841	$ 833	$ 25,475	$ 25,472	-$ 3
1940	Tools, Shop & Garage Equipment	$ 61,684	$ 5,958	$ 55,726	$ 309,954		$ 309,954	$ 30,000	9.08	11.01%	10.00	10.00%	$ 6,137	$ 30,995	$ 1,500	$ 38,633	$ 37,298	-$ 1,335
1945	Measurement & Testing Equipment	$ 49,393	$ 34,826	$ 14,567	$ 44,281		$ 44,281		6.78	14.75%	10.00	10.00%	$ 2,149	$ 4,428	$ -	$ 6,577	$ 6,481	-$ 96
1950	Power Operated Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 344,204	$ 18,980	$ 325,224	$ 128,837		$ 128,837		9.70	10.31%	10.00	10.00%	$ 33,528	$ 12,884	$ -	$ 46,412	$ 44,574	-$ 1,838
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 75,608		$ 75,608	$ 2,259,858		$ 2,259,858	$ 235,352	11.35	8.81%	15.00	6.67%	$ 6,661	$ 150,657	$ 7,845	$ 165,164	$ 165,163	-$ 1
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ 72,697	$ 72,697	$ -	$ -		$ -		10.00	10.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 32,897,303		-$ 32,897,303	$ -		$ -		29.87	3.35%	40.00	2.50%	-$ 1,101,349	$ -	$ -	-$ 1,101,349	-$ 1,101,130	$ 219
2440	Deferred Revenue	-$ 6,481,515		-$ 6,481,515	-$ 16,408,495		-$ 16,408,495	-$ 3,024,069	37.82	2.64%	40.00	2.50%	-$ 171,378	-$ 410,212	-$ 37,801	-$ 619,391	-$ 619,375	$ 16
	Major Spares	$ -			$ 610,000		$ 610,000	$ 15,250			40.00	2.50%	$ -	$ 15,250	$ 191	$ 15,441	$ 15,250	-$ 191
	Total	**$ 75,533,527**	**$ 3,200,995**	**$ 72,332,532**	**$ 45,933,293**	**$ 606,191**	**$ 45,327,102**	**$ 11,937,005**					**$ 2,359,592**	**$ 1,853,859**	**$ 284,621**	**$ 4,498,071**	**$ 4,491,792**	**-$ 6,279**

Appendix 2-C

Depreciation and Amortization Expense - 2023

Account	Description	Book Values							Service Lives				Depreciation Expense					
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated 7	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated 8	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		a	b	c = a-b	d	e	f = d- e	g	h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1609	Capital Contributions Paid	$ 114,707		$ 114,707	$ 1,886,657		$ 1,886,657		37.50	2.67%	40.00	2.50%	$ 3,059	$ 47,166	$ -	$ 50,225	$ 50,073	-$ 152
1611	Computer Software (Formally known as Account 1925)	$ 440,771	$ 440,771	$ -	$ 2,263,721	$ 864,179	$ 1,399,542	$ 551,440		0.00%	5.50	18.18%	$ -	$ 254,462	$ 50,131	$ 304,593	$ 284,063	-$ 20,530
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1805	Land	$ 69,883		$ 69,883	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1808	Buildings	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1810	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 43,417	$ 43,828	-$ 411	$ 980		$ 980	$ 200,000	3.55	28.17%	30.00	3.33%	-$ 116	$ 33	$ 3,333	$ 3,250	$ 2,684	-$ 566
1825	Storage Battery Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1830	Poles, Towers & Fixtures	$ 21,120,953	$ 105,732	$ 21,015,221	$ 11,252,752		$ 11,252,752	$ 2,130,999	39.50	2.53%	45.00	2.22%	$ 532,031	$ 250,061	$ 23,678	$ 805,770	$ 805,667	-$ 103
1835	Overhead Conductors & Devices	$ 10,737,189	$ 12,389	$ 10,724,800	$ 8,160,217		$ 8,160,217	$ 1,187,072	33.66	2.97%	45.00	2.22%	$ 318,622	$ 181,338	$ 13,190	$ 513,149	$ 513,169	$ 20
1840	Underground Conduit	$ 17,556,609	$ 13,916	$ 17,542,693	$ 10,129,903		$ 10,129,903	$ 245,000	30.74	3.25%	40.00	2.50%	$ 570,680	$ 253,248	$ 3,063	$ 826,990	$ 826,993	$ 3
1845	Underground Conductors & Devices	$ 12,125,853	$ 35,797	$ 12,090,056	$ 7,141,565		$ 7,141,565	$ 837,913	32.30	3.10%	40.00	2.50%	$ 374,305	$ 178,539	$ 10,474	$ 563,318	$ 563,344	$ 26
1850	Line Transformers	$ 21,903,085	$ 147,991	$ 21,755,094	$ 13,112,502		$ 13,112,502	$ 2,183,080	31.82	3.14%	40.00	2.50%	$ 683,692	$ 327,813	$ 27,289	$ 1,038,794	$ 1,038,712	-$ 82
1855	Services (Overhead & Underground)	$ 9,002,509		$ 9,002,509	$ 4,701,192		$ 4,701,192	$ 371,654	34.16	2.93%	40.00	2.50%	$ 263,539	$ 117,530	$ 4,646	$ 385,715	$ 385,721	$ 6
1860	Meters	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	$ 5,850,482	$ 3,605,489	$ 2,244,993	$ 9,798,562	$ 23,641	$ 9,774,921	$ 2,439,924	13.00	7.69%	15.00	6.67%	$ 172,692	$ 651,661	$ 81,331	$ 905,684	$ 891,510	-$ 14,174
1905	Land	$ 4,040,000		$ 4,040,000	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1908	Buildings & Fixtures	$ 8,854,219		$ 8,854,219	$ 2,417,222		$ 2,417,222	$ 519,000	49.50	2.02%	50.00	2.00%	$ 178,873	$ 48,344	$ 5,190	$ 232,408	$ 233,947	$ 1,539
1908	Buidling disallowed in 2016 COS	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1910	Leasehold Improvements	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 357,262	$ 59,791	$ 297,471	$ 81,496		$ 81,496		8.74	11.44%	10.00	10.00%	$ 34,036	$ 8,150	$ -	$ 42,185	$ 42,168	-$ 17
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equipment - Hardware	$ 309,831	$ 309,831	$ -	$ 632,346	$ 150,744	$ 481,602	$ 94,500		0.00%	5.50	18.18%	$ -	$ 87,564	$ 8,591	$ 96,155	$ 97,604	$ 1,449
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1930	Transportation Equipment	$ 1,461,807	$ 231,167	$ 1,230,640	$ 2,012,122		$ 2,012,122	$ 451,000	9.54	10.48%	11.45	8.73%	$ 128,998	$ 175,731	$ 19,694	$ 324,423	$ 324,363	-$ 60
1935	Stores Equipment	$ 320,182		$ 320,182	$ 78,093		$ 78,093	$ 30,000	16.17	6.18%	12.00	8.33%	$ 19,801	$ 6,508	$ 1,250	$ 27,559	$ 27,555	-$ 4
1940	Tools, Shop & Garage Equipment	$ 61,684	$ 10,207	$ 51,477	$ 339,954		$ 339,954	$ 45,000	9.08	11.01%	10.00	10.00%	$ 5,669	$ 33,995	$ 2,250	$ 41,915	$ 40,452	-$ 1,463
1945	Measurement & Testing Equipment	$ 49,393	$ 58,457	-$ 9,064	$ 44,281		$ 44,281		4.68	21.37%	10.00	10.00%	-$ 1,937	$ 4,428	$ -	$ 2,491	$ 4,546	$ 2,055
1950	Power Operated Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1955	Communications Equipment	$ 344,204	$ 29,321	$ 314,883	$ 128,837		$ 128,837		9.23	10.83%	10.00	10.00%	$ 34,115	$ 12,884	$ -	$ 46,999	$ 43,583	-$ 3,416
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1970	Load Management Controls Customer Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1980	System Supervisor Equipment	$ 75,608		$ 75,608	$ 2,495,210		$ 2,495,210	$ 397,393	12.90	7.75%	15.00	6.67%	$ 5,861	$ 166,347	$ 13,246	$ 185,455	$ 186,255	$ 800
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -		$ -			0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1990	Other Tangible Property	$ 72,697	$ 72,697	$ -	$ -		$ -		-	0.00%	10.00	10.00%	$ -	$ -	$ -	$ -		$ -
1995	Contributions & Grants	-$ 32,897,303		-$ 32,897,303	$ -		$ -		30.01	3.33%		0.00%	-$ 1,096,211	$ -	$ -	-$ 1,096,211	-$ 1,095,885	$ 326
2440	Deferred Revenue	-$ 6,481,515		-$ 6,481,515	-$ 19,432,564		-$ 19,432,564	-$ 2,539,386	37.93	2.64%	40.00	2.50%	-$ 170,881	-$ 485,814	-$ 31,742	-$ 688,437	-$ 688,415	$ 22
	Major Spares	$ -			$ 625,250			$ 15,250			40.00	2.50%	$ -	$ -	$ 191	$ 191	$ 15,250	$ 15,059
	Total	**$ 75,533,527**	**$ 5,177,384**	**$ 70,356,143**	**$ 57,870,298**	**$ 1,038,564**	**$ 56,206,484**	**$ 9,159,839**					**$ 2,056,828**	**$ 2,319,988**	**$ 235,803**	**$ 4,612,620**	**$ 4,593,359**	**-$ 19,261**

EXHIBIT 4

ATTACHMENT 4-9

2023 TEST YEAR INCOME TAX/PILS WORKFORM

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Version 1.00

Utility Name	Milton Hydro Distribution Inc.
Assigned EB Number	EB-2022-0049
Name and Title	Dan Gapic
Phone Number	905.876.4611
Email Address	gapicd@miltonhydro.com
Date	04/06/2022
Last COS Re-based Year	**2016**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

Ontario Energy Board

Income Tax/PILs Workform for 2022 Filers

1. Info
S. Summary
A. Data Input Sheet
B. Tax Rates & Exemptions

Historical Year
H0 - PILs, Tax Provision Historical Year
H1 - Adj. Taxable Income Historical Year
H4 - Schedule 4 Loss Carry Forward Historical Year
H8 - Schedule 8 Historical
H13 - Schedule 13 Tax Reserves Historical

Bridge Year
B0 - PILs,Tax Provision Bridge Year
B1 - Adj. Taxable Income Bridge Year
B4 - Schedule 4 Loss Carry Forward Bridge Year
B8 - Schedule 8 CCA Bridge Year
B13 - Schedule 13 Tax Reserves Bridge Year

Test Year
T0 PILs, Tax Provision Test Year
T1 Taxable Income Test Year
T4 Schedule 4 Loss Carry Forward Test Year
T8 Schedule 8 CCA Test Year
T13 Schedule 13 Reserve Test Year

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

No inputs required on this worksheet.

Inputs on Service Revenue Requirement Worksheet

The Service Revenue Requirement is in the 'Revenue Requirement Workform' - Tab 3.

Item	Working Paper Reference		
Adjustments required to arrive at taxable income	as below	**-2,021,577**	
Test Year - Payments in Lieu of Taxes (PILs)	T0	**502,825**	
Test Year - Grossed-up PILs	T0	**684,115**	
Effective Federal Tax Rate	T0	**15.0%**	
Effective Ontario Tax Rate	T0	**11.5%**	
Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	3,934,446	
Taxable Income	T1	1,912,869	
Difference	calculated	-2,021,577	as above

Income Tax/PILs Workform for 2023 Filers

Integrity Checks

The applicant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or provide an explanation if this is not the case:

	Item	**Utility Confirmation (Y/N)**	**Notes**
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	
2	The capital additions and deductions in the CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non-distribution tax amounts on Schedule 8.	Y	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the CCA Schedule 8 for the same years filed in the application	Y	
5	Loss carry-forwards, if any, from prior year tax returns' Schedule 4 agree with those disclosed in the application	Y	
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	N	There were no loss carry-forwards
7	CCA is maximized even if there are tax loss carry-forwards	Y	
8	Other post-employment benefits and pension expenses that are added back on Schedule 1 to reconcile accounting income to net income for tax purposes agree with the OM&A analysis for compensation. The amounts deducted are reasonable when compared with the notes to the audited financial statements, Financial Services Commission of Ontario reports, and actuarial valuations.	Y	
9	The income tax rate used to calculate the tax expense is consistent with the utility's actual tax facts and evidence filed in the application	Y	

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

			Test Year	Bridge Year	
Rate Base		S	**$ 113,581,019**	**$ 107,957,483**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$ 4,543,241	*W = S * T*	
Deemed Long Term Debt %	56.00%	U	$ 63,605,370	*X = S * U*	
Deemed Equity %	40.00%	V	$ 45,432,407	*Y = S * V*	
Short Term Interest Rate	1.17%	Z	$ 53,156	*AC = W * Z*	
Long Term Interest	3.54%	AA	$ 2,250,497	*AD = X * AA*	
Return on Equity (Regulatory Income)	8.66%	AB	$ 3,934,446	*AE = Y * AB*	T1
Return on Rate Base			**$ 6,238,100**	*AF = AC + AD + AE*	

Questions that must be answered

	Historical Year	Bridge Year	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Tax Rates Federal & Provincial As of MMM XX, 2019	Effective January 1, 2016	Effective January 1, 2017	Effective January 1, 2018	Effective January 1, 2019	Effective January 1, 2020	Effective January 1, 2021	Effective January 1, 2022	Effective January 1, 2023
Federal income tax								
General Corporate Rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal Tax Abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted Federal Rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate Reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario Income Tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined Federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business								
Federal Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Federal Small Business Rate	11.00%	10.50%	10.50%	10.00%	9.00%	9.00%	9.00%	9.00%
Ontario Small Business Rate	4.50%	4.50%	3.50%	3.50%	3.20%	3.20%	3.20%	3.20%

Notes

1. The Ontario Energy Board's proxy for taxable capital is rate base.
2. Regarding the small business deduction, if applicable,
   a. If taxable capital exceeds $15 million, the small business rate will not be applicable.
   b. If taxable capital is below $10 million, the small business rate would be applicable.
   c. If taxable capital is between $10 million and $15 million, the appropriate small business rate will be calculated.

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

					Wires Only	
Regulatory Taxable Income				H1	$ 1,067,495	A
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	B			
	Federal tax rate (Maximum 15%)	15.00%	C			
	Combined tax rate (Maximum 26.5%)				26.50%	D = B+C
Total Income Taxes					**$ 282,886**	E = A * D
Investment Tax Credits						F
Miscellaneous Tax Credits						G
Total Tax Credits					$ -	H = F + G
Corporate PILs/Income Tax Provision for Historical Year					**$ 282,886**	I = E - H

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	**(A + 101 + 102)**	4,012,025		4,012,025
Additions:				
Interest and penalties on taxes	103	0		0
Amortization of tangible assets	104	4,391,144		4,391,144
Amortization of intangible assets	106	345,042		345,042
Recapture of capital cost allowance from Schedule 8	107			0
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108			0
Loss in equity of subsidiaries and affiliates	110	141,009		141,009
Loss on disposal of assets	111			0
Charitable donations and gifts from Schedule 2	112			0
Taxable capital gains from Schedule 6	113			0
Political contributions	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	2,071		2,071
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements – balance at the end of the year	126	617,629		617,629
Soft costs on construction and renovation of buildings	127			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other additions				
Interest Expensed on Capital Leases	295			0
Realized Income from Deferred Credit Accounts	295			0
Pensions	295			0
Non-deductible penalties	295			0
PILs regulatory smoothing adjustment	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))		20,547,338		20,547,338
Prior Year Investment Tax Credits received				0
Total Additions		**26,044,234**	**0**	**26,044,234**

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Deductions:				
Gain on disposal of assets per financial statements	401	0		0
Non-taxable dividends under section 83	402	0		0
Capital cost allowance from Schedule 8	403	6,404,034		6,404,034
Terminal loss from Schedule 8	404	0		0
Allowable business investment loss	406	0		0
Deferred and prepaid expenses	409	0		0
Scientific research expenses claimed in year	411	0		0
Tax reserves claimed in current year	413	0		0
Reserves from financial statements - balance at beginning of year	414	669,800		669,800
Contributions to deferred income plans	416	0		0
Book income of joint venture or partnership	305	0		0
Equity in income from subsidiary or affiliates	306	0		0
Other deductions				
Interest capitalized for accounting deducted for tax	395			0
Capital Lease Payments	395			0
Non-taxable imputed interest income on deferral and variance accounts	395			0
Amortization of Deferred Revenue	395	548,596		548,596
Unrealized gains on derivatives	395	818,996		818,996
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve		20,547,338		20,547,338
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Total Deductions		**28,988,764**	**0**	**28,988,764**
Net Income for Tax Purposes		**1,067,495**	**0**	**1,067,495**
Charitable donations from Schedule 2	311			0
Taxable dividends received under section 112 or 113	320			0
Non-capital losses of previous tax years from Schedule 4	331			0
Net capital losses of previous tax years from Schedule 4	332			0
Limited partnership losses of previous tax years from Schedule 4	335			0
TAXABLE INCOME		**1,067,495**	**0**	**1,067,495**

Income Tax/PILs Workform for 2023 Filers

Schedule 4 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	0		0	B4

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Buildings, Distribution System (acq'd post 1987)	$ 17,656,852		$ 17,656,852
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	$ 7,330,028		$ 7,330,028
2	Distribution System (acq'd pre 1988)			$ -
3	Buildings (acq'd pre 1988)			$ -
6	Certain Buildings; Fences			$ -
8	General Office Equipment, Furniture, Fixtures	$ 2,051,045		$ 2,051,045
10	Motor Vehicles, Fleet	$ 411,493		$ 411,493
10.1	Certain Automobiles			$ -
12	Computer Application Software (Non-Systems)			$ -
13_1	Lease # 1			$ -
13_2	Lease # 2			$ -
13_3	Lease # 3			$ -
13_4	Lease # 4			$ -
14	Limited Period Patents, Franchises, Concessions or Licences			$ -
14.1	Eligible Capital Property (acq'd pre 2017)			$ -
14.1	Eligible Capital Property (acq'd post 2016)	$ 1,624,351		$ 1,624,351
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage			$ -
42	Fibre Optic Cable			$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	$ 24		$ 24
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			$ -
47	Distribution System (acq'd post Feb 22/05)	$ 45,949,061		$ 45,949,061
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	$ 40,996		$ 40,996
95	CWIP	$ 6,679,110		$ 6,679,110
	SUB-TOTAL - UCC	81,742,960	0	81,742,960

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital gains reserves ss.40(1)			-
Tax reserves not deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			-
Reserve for undelivered goods and services not rendered ss. 20(1)(m)			-
Reserve for unpaid amounts ss. 20(1)(n)			-
Debt & share issue expenses ss. 20(1)(e)			-
Other tax reserves			-
Total	-	-	-
Financial Statement Reserves (not deductible for Tax Purposes)			
General reserve for inventory obsolescence (non-specific)			-
General reserve for bad debts			-
Accrued Employee Future Benefits:			-
- Medical and Life Insurance	617,629		617,629
-Short & Long-term Disability			-
-Accmulated Sick Leave			-
- Termination Cost			-
- Other Post-Employment Benefits			-
Provision for Environmental Costs			-
Restructuring Costs			-
Accrued Contingent Litigation Costs			-
Accrued Self-Insurance Costs			-
Other Contingent Liabilities			-
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			-
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			-
Total	**617,629**	-	**617,629**

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

PILS Tax Provision - Bridge Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate		Reference	Wires Only	
Regulatory Taxable Income						B1	-$ 190,395	A
Ontario (Max 11.5%)	11.5%	11.5%	-$ 21,895	11.5%	B			
Federal (Max 15%)	15.0%	15.0%	-$ 28,559	15.0%	C			
Combined effective tax rate (Max 26.5%)							26.50%	D = B + C
Total Income Taxes							**-$ 50,455**	E = A * D
Investment Tax Credits							-$ 66,854	F
Miscellaneous Tax Credits								G
Total Tax Credits							**-$ 66,854**	H = F + G
Corporate PILs/Income Tax Provision for Bridge Year							**$ 16,399**	I = E - H

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Income Tax/PILs Workform for 2023 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	(A + 101 + 102)		2,714,447
Additions:			
Interest and penalties on taxes	103		0
Amortization of tangible assets	104		4,782,292
Amortization of intangible assets	106		313,323
Recapture of capital cost allowance from Schedule 8	107	B8	0
Income inclusion under subparagraph 13(38)(d)(iii)	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		350,000
Loss on disposal of assets	111		
Charitable donations and gifts from Schedule 2	112		
Taxable capital gains	113		
Political contributions	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		4,780
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	0
Reserves from financial statements- balance at end of year	126	B13	617,629
Soft costs on construction and renovation of buildings	127		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			20,553,396
Prior Year Investment Tax Credits received			
Total Additions			**26,621,421**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	7,735,863
Terminal loss from Schedule 8	404	B8	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	0
Reserves from financial statements - balance at beginning of year	414	B13	617,629
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions			
Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		
Non-taxable imputed interest income on deferral and variance accounts	395		
Amortization of Deferred Revenue	395		619,375
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			

Income Tax/PILs Workform for 2023 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Deferred Revenue - ITA 20(1)(m) reserve			20,553,396
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**29,526,263**
Net Income for Tax Purposes		calculated	**-190,395**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	B4	0
Net capital losses of previous tax years from Schedule 4	332	B4	0
Limited partnership losses of previous tax years from Schedule 4	335		
TAXABLE INCOME		calculated	**-190,395**

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**
Actual Historical	H4	0
Amount to be used in Bridge Year	B1	0
Loss Carry Forward Generated in Bridge Year (if any)	B1	190,395
Other Adjustments		
Balance available for use post Bridge Year	calculated	190,395

Net Capital Loss Carry Forward Deduction		**Total**
Actual Historical	H4	0
Amount to be used in Bridge Year		
Loss Carry Forward Generated in Bridge Year (if any)	B1	
Other Adjustments		
Balance available for use post Bridge Year	calculated	0

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 8 CCA - Bridge Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the bridge year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the bridge year (column 9 minus column 17)
1	Buildings, Distribution System (acq'd post 1987)	H8	$ 17,656,852							$ 17,656,852	$ -	$ -	0.50	$ -	$ -	4%			$ 706,274		$ 16,950,578
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	H8	$ 7,330,028	$ 593,000	$ 593,000					$ 7,923,028	$ -	$ 593,000	0.50	$ 296,500	$ -	6%			$ 493,172		$ 7,429,856
2	Distribution System (acq'd pre 1988)	H8	$ -							$ -	$ -	$ -		$ -	$ -	6%			$ -		$ -
3	Buildings (acq'd pre 1988)	H8	$ -							$ -	$ -	$ -		$ -	$ -	5%			$ -		$ -
6	Certain Buildings; Fences	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -
8	General Office Equipment, Furniture, Fixtures	H8	$ 2,051,045	$ 285,352	$ 285,352					$ 2,336,397	$ -	$ 285,352	0.50	$ 142,676	$ -	20%			$ 495,815		$ 1,840,582
10	Motor Vehicles, Fleet	H8	$ 411,493	$ 751,500	$ 751,500					$ 1,162,993	$ -	$ 751,500	0.50	$ 375,750	$ -	30%			$ 461,623		$ 701,370
10.1	Certain Automobiles	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
12	Computer Application Software (Non-Systems)	H8	$ -	$ 547,060	$ 547,060					$ 547,060	$ -	$ 547,060	0.00	$ -	$ -	100%			$ 547,060		$ -
13_1	Lease # 1	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
13_2	Lease # 2	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
13_3	Lease # 3	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
13_4	Lease # 4	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
14	Limited Period Patents, Franchises, Concessions or Licences	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	H8	$ -							$ -	$ -	$ -		$ -	$ -	7%			$ -		$ -
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	H8	$ 1,624,351							$ 1,624,351	$ -	$ -	0.50	$ -	$ -	5%			$ 81,218		$ 1,543,134
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -
42	Fibre Optic Cable	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	H8	$ 24							$ 24	$ -	$ -		$ -	$ -	45%			$ 11		$ 13
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
47	Distribution System (acq'd post Feb 22/05)	H8	$ 45,949,061	$ 9,627,343	$ 9,627,343					$ 55,576,404	$ -	$ 9,627,343	0.50	$ 4,813,672	$ -	8%			$ 4,831,206		$ 50,745,198
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	H8	$ 40,996	$ 117,500	$ 117,500					$ 158,496	$ -	$ 117,500	0.50	$ 58,750	$ -	55%			$ 119,485		$ 39,011
95	CWIP	H8	$ 6,679,110	-$ 1,760,185	-$ 1,760,185					$ 4,918,925	$ -	$ -	0.00	$ -	$ -	0%			$ -		$ 4,918,925
	TOTALS		**$ 81,742,960**	**$ 10,161,570**	**$ 10,161,570**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 91,904,530**	**$ -**	**$ 11,921,755**		**$ 5,687,348**	**$ -**		**$ -**	**$ -**	**$ 7,735,863**	B1	**$ 84,168,667**

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Reference	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Bridge Year Adjustments		Balance for Bridge Year		Change During the Year	Disallowed Expenses
						Additions	Disposals				
Capital gains reserves ss.40(1)	H13	0		0				0	T13	0	
Tax Reserves Not Deducted for Accounting Purposes											
Reserve for doubtful accounts ss. 20(1)(l)	H13	0		0				0	T13	0	
Reserve for goods and services not delivered ss. 20(1)(m)	H13	0		0				0	T13	0	
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0	
Debt & share issue expenses ss. 20(1)(e)	H13	0		0				0	T13	0	
Other tax reserves	H13	0		0				0	T13	0	
Total		**0**	**0**	**0**	B1	**0**	**0**	**0**	B1	**0**	**0**
Financial statement reserves (not deductible for tax purposes)											
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0	
General Reserve for Bad Debts	H13	0		0				0	T13	0	
Accrued Employee Future Benefits:	H13	0		0				0	T13	0	
- Medical and Life Insurance	H13	617,629		617,629		0		617,629	T13	0	
- Short & Long-term Disability	H13	0		0				0	T13	0	
- Accumulated Sick Leave	H13	0		0				0	T13	0	
- Termination Cost	H13	0		0				0	T13	0	
- Other Post-Employment Benefits	H13	0		0				0	T13	0	
Provision for Environmental Costs	H13	0		0				0	T13	0	
Restructuring Costs	H13	0		0				0	T13	0	
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0	
Accrued Self-Insurance Costs	H13	0		0				0	T13	0	
Other Contingent Liabilities	H13	0		0				0	T13	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0	
Other	H13	0		0				0	T13	0	
Total		**617,629**	**0**	**617,629**	B1	**0**	**0**	**617,629**	B1	**0**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income						T1	$ 1,912,869	A
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				
Ontario (Max 11.5%)	11.5%	11.5%	$ 219,980	11.5%	B			
Federal (Max 15%)	15.0%	15.0%	$ 286,930	15.0%	C			
Combined effective tax rate (Max 26.5%)							26.50%	D = B + C
Total Income Taxes							**$ 506,910**	E = A * D
Investment Tax Credits								F
Miscellaneous Tax Credits							$ 4,085	G
Total Tax Credits							**$ 4,085**	H = F + G
Corporate PILs/Income Tax Provision for Test Year							**$ 502,825**	I = E - H
Corporate PILs/Income Tax Provision Gross Up [1]					73.50%	J = 1-D	**$ 181,291**	K = I/J-I
Income Tax (grossed-up)							**$ 684,115**	L = K + I

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	3,934,446
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		4,932,386
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		334,136
Recapture of capital cost allowance from Schedule 8	107	T8	0
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		350,000
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		5,000
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	617,629
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
PILs regulatory smoothing adjustment			773,421
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			22,404,815
Prior Year Investment Tax Credits received			

Ontario Energy Board

Income Tax/PILs Workforms for 2023 Filers

Total Additions			**29,417,387**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	7,728,107
Terminal loss from Schedule 8	404	T8	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	617,629
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions			
Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		
Non-taxable imputed interest income on deferral and variance accounts	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			22,404,815
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Amortization of Deferred Revenue			688,413
Total Deductions		calculated	**31,438,964**
NET INCOME FOR TAX PURPOSES		calculated	**1,912,869**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	T4	0
Net capital losses of previous tax years from Schedule 4	332	T4	0
Limited partnership losses of previous tax years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**1,912,869** T0

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 4 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Working Paper Reference	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	190,395		190,395
Amount to be used in Test Year and Price Cap Years	T1	190,395		190,395
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	calculated	190,395	190,395	0
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments				0
Balance available for use in Future Years	calculated	0		0

Net Capital Loss Carry Forward Deduction		Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		0		0

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 8 CCA - Test Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the test year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the test year (column 9 minus column 17)
1	Buildings, Distribution System (acq'd post 1987)	B8	$ 16,950,578							$ 16,950,578	$ -	$ -	0.50	$ -	$ -	4%			$ 678,023		$ 16,272,555
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	B8	$ 7,429,856	$ 519,000	$ 519,000					$ 7,948,856	$ -	$ 519,000	0.50	$ 259,500	$ -	6%			$ 492,501		$ 7,456,355
2	Distribution System (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -	6%			$ -		$ -
3	Buildings (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -	5%			$ -		$ -
6	Certain Buildings; Fences	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -
8	General Office Equipment, Furniture, Fixtures	B8	$ 1,840,582	$ 472,393	$ 472,393					$ 2,312,975	$ -	$ 472,393	0.50	$ 236,196	$ -	20%			$ 509,834		$ 1,803,141
10	Motor Vehicles, Fleet	B8	$ 701,370	$ 451,000	$ 451,000					$ 1,152,370	$ -	$ 451,000	0.50	$ 225,500	$ -	30%			$ 413,361		$ 739,009
10.1	Certain Automobiles	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
12	Computer Application Software (Non-Systems)	B8	$ -	$ 551,440	$ 551,440					$ 551,440	$ -	$ 551,440	0.00	$ -	$ -	100%			$ 551,440		$ -
13_1	Lease # 1	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
13_2	Lease # 2	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
13_3	Lease # 3	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
13_4	Lease # 4	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
14	Limited Period Patents, Franchises, Concessions or Licences	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	B8	$ -							$ -	$ -	$ -		$ -	$ -	7%			$ -		$ -
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	B8	$ 1,543,134							$ 1,543,134	$ -	$ -	0.50	$ -	$ -	5%			$ 77,157		$ 1,465,977
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -
42	Fibre Optic Cable	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	B8	$ 13							$ 13	$ -	$ -		$ -	$ -	45%			$ 6		$ 7
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
47	Distribution System (acq'd post Feb 22/05)	B8	$ 50,745,198	$ 7,056,256	$ 7,056,256					$ 57,801,454	$ -	$ 7,056,256	0.50	$ 3,528,128	$ -	8%			$ 4,906,367		$ 52,895,088
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	B8	$ 39,011	$ 94,500	$ 94,500					$ 133,511	$ -	$ 94,500	0.50	$ 47,250	$ -	55%			$ 99,418		$ 34,092
95	CWIP	B8	$ 4,918,925	$ 721,593	$ 721,593					$ 5,640,518	$ -	$ 721,593	0.00	$ -	$ -	0%			$ -		$ 5,640,518
	TOTALS		**$ 84,168,667**	**$ 9,866,182**	**$ 9,866,182**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 94,034,849**	**$ -**	**$ 9,866,182**		**$ 4,296,574**	**$ -**		**$ -**	**$ -**	**$ 7,728,107**	T1	**$ 86,306,742**

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Test Year	Adjusted Utility Balance		Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	0		0				0		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	0		0				0		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0				0		0	
Total		**0**	**0**	**0**	T1	**0**	**0**	**0**	T1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	0		0				0		0	
Accrued Employee Future Benefits:	B13	0		0				0		0	
- Medical and Life Insurance	B13	617,629		617,629				617,629		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	0		0				0		0	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	0		0				0		0	
Total		**617,629**	**0**	**617,629**	T1	**0**	**0**	**617,629**	T1	**0**	**0**

EXHIBIT 4

ATTACHMENT 4-10

MILTON HYDRO 2020 T2 CORPORATION INCOME TAX RETURN

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

Identification

Business number (BN) 001 89573 0216 RC0001

Corporation's name
002 MILTON HYDRO DISTRIBUTION INC.

Address of head office
Has this address changed since the last time we were notified? . . . . 010 Yes [ ] No [X]
If **yes**, complete lines 011 to 018.
011 200 Chisholm Drive
012
City: 015 Milton
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal or ZIP code: 018 L9T 3G9

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . 020 Yes [ ] No [X]
If **yes**, complete lines 021 to 028.
021 c/o Igor Rusic
022 200 Chisholm Drive
023
City: 025 Milton
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal or ZIP code: 028 L9T 3G9

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? . . . . 030 Yes [ ] No [X]
If **yes**, complete lines 031 to 038.
031
032
City: 035
Province, territory, or state: 036
Country (other than Canada): 037
Postal or ZIP code: 038

040 **Type of corporation at the end of the tax year** (tick one)
- [X] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [ ] 4 Corporation controlled by a public corporation
- [ ] 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . 043 Year Month Day

To which tax year does this return apply?
Tax year start: 060 Year Month Day 2020-01-01
Tax year-end: 061 Year Month Day 2020-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . 063 Yes [ ] No [X]
If **yes**, provide the date control was acquired . . . . 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . 066 Yes [ ] No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 Yes [ ] No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 Yes [ ] No [X]
Amalgamation? . . . . 071 Yes [ ] No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 Yes [ ] No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 Yes [ ] No [X]

Is this the final return up to dissolution? . . . . 078 Yes [ ] No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 Yes [X] No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 Yes [ ] No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area
095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170		29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet web pages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit?	253		T1131
Is the corporation claiming a film or video production services tax credit?	254		T1177
Is the corporation claiming a Canadian journalism labour tax credit?	272		58
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		Yes	No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	X	
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? ..... 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	HYDRO DISTRIBUTION	285	100.000 %
286		287	%
288		289	%

		Yes	No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible ..... 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? ..... 295 Yes No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI	300		1,188,360	A
Deduct:				
Charitable donations from Schedule 2	311	4,000		
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine made before March 22, 2017, from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Employer deduction for non-qualified securities under an employee stock options agreement		a		
Subtotal		4,000 ▶	4,000	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			1,184,360	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		1,184,360	
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7	400	1,188,360	A
Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	1,184,360	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction

Amount C 500,000 x 415 *** 246,144 D / 11,250 = 10,939,733 E

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** 417 6,620 – 50,000 = F

Amount C 500,000 / 100,000 x Amount F = G

The greater of amount E and amount G	422	10,939,733	H
Reduced business limit (amount C **minus** amount H) (if negative, enter "0")	426		I
Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below)			J
Reduced business limit after assignment (amount I **minus** amount J)	428		K
Small business deduction – Amount A, B, C, or K, whichever is the least ____ x 19 % =	430		

Enter amount from line 430 at amount J on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations for each tax year that ended in the preceding calendar year. Each corporation with such income has to file a Schedule 7. For a corporation's first tax year that starts after 2018, this amount is reported at line 744 of the corresponding Schedule 7. Otherwise, this amount is the total of all amounts reported at line 745 of the corresponding Schedule 7 of the corporation for each tax year that ended in the preceding calendar year.

Specified corporate income and assignment under subsection 125(3.2)

	L1 Name of corporation receiving the income and assigned amount	L Business number of the corporation receiving the assigned amount 490	M Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column L [3] 500	N Business limit assigned to corporation identified in column L [4] 505
1.				
		Total	510	Total 515

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income (other than specified farming or fishing income of the corporation for the year) from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column M in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 426.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3				1,184,360	A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27			B		
Amount 13K from Part 13 of Schedule 27			C		
Personal services business income	432		D		
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least			E		
Aggregate investment income from line 440 on page 6*			F		
Subtotal (**add** amounts B to F)			▶		G
Amount A **minus** amount G (if negative, enter "0")				1,184,360	H
General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 %				153,967	I

Enter amount I on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3					J
Lesser of amounts 9B and 9H from Part 9 of Schedule 27			K		
Amount 13K from Part 13 of Schedule 27			L		
Personal services business income	434		M		
Subtotal (**add** amounts K to M)			▶		N
Amount J **minus** amount N (if negative, enter "0")					O
General tax reduction – Amount O **multiplied** by 13 %					P

Enter amount P on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 30 2/3 % =				A
Foreign non-business income tax credit from line 632 on page 8		B		
Foreign investment income from Schedule 7 . . . . **445** ________ x 8 % =		C		
Subtotal (amount B **minus** amount C) (if negative, enter "0")		▶		D
Amount A **minus** amount D (if negative, enter "0")				E
Taxable income from line 360 on page 3	1,184,360	F		
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least . . . . ________ G				
Foreign non-business income tax credit from line 632 on page 8 . . . . ________ x 75 / 29 = ________ H				
Foreign business income tax credit from line 636 on page 8 . . ________ x 4 = ________ I				
Subtotal (**add** amounts G to I) ________ ▶		J		
Subtotal (amount F **minus** amount J)	1,184,360	K	x 30 2/3 % = 363,204	L
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9)			177,654	M
Refundable portion of Part I tax – Amount E, L, or M, whichever is the least **450**				N

Refundable dividend tax on hand

Refundable dividend tax on hand (RDTOH) at the end of the previous tax year	460			
Dividend refund for the previous tax year	465			
Net RDTOH transferred on an amalgamation or the wind-up of a subsidiary	480			
Subtotal (line 460 **minus** line 465 **plus** line 480)				A
General rate income pool (GRIP) at the end of the previous tax year (from line 100 of Schedule 53)				B
Total eligible dividends paid in the previous tax year (from line 300 of Schedule 53)			C	
Total excessive eligible dividend designation in the previous tax year (from line 310 of Schedule 53)			D	
Subtotal (amount C **minus** amount D) (if negative, enter "0")			►	E
Net GRIP at the end of the previous tax year (amount B **minus** amount E) (if negative, enter "0")			F	
GRIP transferred on an amalgamation or the wind-up of a subsidiary (total of lines 230 and 240 of Schedule 53)			G	
Subtotal (amount F **plus** amount G)			►	H
Amount H **multiplied** by 38 1 / 3 %				I
Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A or I, whichever is less, otherwise, use line 530 of the preceding tax year)	520			J
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A **minus** amount I, otherwise, use line 545 of the preceding tax year) (if negative, enter "0")	535			K
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)			L	
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)			M	
Subtotal (amount L **plus** amount M)			►	N
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary	525			O
ERDTOH dividend refund for the previous tax year	570			P
Refundable portion of Part I tax (from line 450 on page 6)				Q
Part IV tax before deductions (amount 2A from Schedule 3)			R	
Part IV tax allocated to ERDTOH (amount N)			S	
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)			T	
Subtotal (amount R **minus** total of amounts S and T)			►	U
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary	540			V
NERDTOH dividend refund for the previous tax year	575			W
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)				X
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount U **minus** amount X) (if negative enter "0")				Y
NERDTOH at the end of the tax year (total of amounts K, Q, V, and Y **minus** amount W) (if negative, enter "0")	545			
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount N **minus** the amount, if any, by which amount X exceeds amount U) (if negative, enter "0")				Z
ERDTOH at the end of the tax year (total of amounts J, O, and Z **minus** amount P) (if negative, enter "0")	530			

Dividend refund

38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)		AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)	575,000	DD
NERDTOH balance at the end of the tax year (line 545)		EE
Non-eligible dividend refund (amount DD or EE, whichever is less)		FF
Amount DD **minus** amount EE (if negative, enter "0")	575,000	GG
Amount BB **minus** amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund – Amount CC **plus** amount FF **plus** amount II		JJ

Enter amount JJ on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income (from line 360 on page 3) **multiplied** by 38 %		550	450,057	A
Additional tax on personal services business income (section 123.5)				
Taxable income from a personal services business	555	x 5 % = 560		B
Recapture of investment tax credit from Schedule 31		602		C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			D
Taxable income from line 360 on page 3	1,184,360 E		
Deduct: Amount from line 400, 405, 410, or 428 on page 4, whichever is the least	F		
Net amount (amount E **minus** amount F)	1,184,360 ▶	1,184,360	G

Refundable tax on CCPC's investment income – 10 2 / 3 % of whichever is less: amount D or amount G	604		H
Subtotal (**add** amounts A, B, C, and H)		450,057	I

Deduct:

Small business deduction from line 430 on page 4				J
Federal tax abatement	608	118,436		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624				
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount I on page 5	638	153,967		
General tax reduction from amount P on page 5	639			
Federal logging tax credit from Schedule 21	640			
Eligible Canadian bank deduction under section 125.21	641			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652			
Subtotal		272,403 ▶	272,403	K
Part I tax payable – Amount I **minus** amount K			177,654	L

Enter amount L on line 700 on page 9.

Privacy statement

Personal information (including the SIN) is collected for the purposes of the administration or enforcement of the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties, or other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at **canada.ca/cra-info-source**.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	177,654
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		177,654

Add provincial or territorial tax:

Provincial or territorial jurisdiction **750** ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	136,201
Total tax payable	770	313,855 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount JJ on page 7	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit (Form T1131)	796		
Film or video production services tax credit (Form T1177)	797		
Canadian journalism labour tax credit from Schedule 58	798		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	692,388	
Total credits	890	692,388	692,388 B
Balance (amount A **minus** amount B)			-378,533

Refund code **894** 1 Refund 378,533

If the result is negative, you have a **refund**.
If the result is positive, you have a **balance owing**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance owing

For information on how to make your payment, go to **canada.ca/payments**.

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number **918** Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? **896** Yes ☐ No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number **920** A6698

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, **950** Rusic (Last name) **951** Igor (First name) **954** Chief Financial Officer (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 June 14, 2021 — Date (yyyy/mm/dd)

Igor Rusic — Signature of the authorized signing officer of the corporation

956 (289) 429-5210 — Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below **957** Yes ☒ No ☐

958 Name of other authorized person **959** Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. **990** 1

MILTON HYDRO DISTRIBUTION INC.
Period ended December 31, 2020
BN 89573 0216 RC0001
Regulation 1101(5b.1) Election

The taxpayer hereby elects pursuant to subsection 1101(5b.1) of the Income Tax Regulations of Canada, to include each eligible non-residential building acquired during the year in a separate prescribed class.

Financial Statements of

MILTON HYDRO DISTRIBUTION INC.

And Independent Auditors' Report thereon

Year ended December 31, 2020

KPMG LLP
Commerce Place
21 King Street West, Suite 700
Hamilton ON L8P 4W7
Canada
Tel 905-523-8200
Fax 905-523-2222

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Milton Hydro Distribution Inc.:

Opinion

We have audited the financial statements of Milton Hydro Distribution Inc. (the Corporation), which comprise:

- the statement of financial position as at December 31, 2020
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2020, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Corporation's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Corporation's internal control.

KPMG

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Corporation's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Hamilton, Canada
April 26, 2021

MILTON HYDRO DISTRIBUTION INC.

Statement of Financial Position

December 31, 2020, with comparative information for 2019

	Note	2020	2019
Assets			
Current assets			
Cash and cash equivalents	4	$ 6,221,213	$ 10,676,206
Accounts receivable	5 and 20(b)	12,574,823	10,444,977
Due from related party	20	503,997	495,318
Unbilled revenue		10,852,013	10,991,881
Income taxes receivable		180,864	–
Materials and supplies	6	1,500,336	1,548,149
Prepaid expenses		882,297	797,519Total
Total current assets		32,715,543	34,954,050
Non-current assets			
Property, plant and equipment	7	113,878,169	108,554,143
Intangible assets	8	2,730,183	2,955,699
Deferred tax assets	9	5,731,083	4,638,160
Total non-current assets		122,339,435	116,148,002
Total assets		155,054,978	151,102,052
Regulatory debit balances	10	9,538,932	9,142,330
Total assets and regulatory debit balances		$ 164,593,910	$ 160,244,382

MILTON HYDRO DISTRIBUTION INC.

Statement of Financial Position

December 31, 2020, with comparative information for 2019

	Note	2020	2019
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	$ 16,482,397	$ 18,334,459
Long-term debt due within one year	12	1,686,013	1,532,350
Due to related parties	20	354,895	223,793
Income taxes payable		–	1,445,307
Customer deposits		3,667,344	3,701,064
Total current liabilities		22,190,649	25,236,973
Non-current liabilities			
Long-term debt	12	60,044,075	56,392,096
Post-employment benefits	13	669,800	509,917
Deferred revenue		18,148,702	16,330,100
Other liabilities		3,055,593	2,534,276
Deferred tax liabilities	9	8,576,468	7,628,018
Total non-current liabilities		90,494,638	83,394,407
Total liabilities		112,685,287	108,631,380
Equity			
Share capital	14	17,008,908	17,008,908
Retained earnings		27,903,122	28,246,776
Accumulated other comprehensive loss		(211,253)	(113,119)
Total equity		44,700,777	45,142,565
Total liabilities and equity		157,386,064	153,773,945
Regulatory credit balances	10	7,207,846	6,470,437
Commitments and contingencies	18		
COVID-19	22		
Total liabilities, equity and regulatory credit balances		$ 164,593,910	$ 160,244,382

See accompanying notes to the financial statements.

On behalf of the Board:

____________________________ Director ____________________________ Director

MILTON HYDRO DISTRIBUTION INC.

Statement of Comprehensive Income

Year ended December 31, 2020, with comparative information for 2019

	Note	2020	2019
Revenue			
Distribution revenue		$ 18,556,556	$ 18,203,473
Other operating revenue		2,009,790	2,071,882
		20,566,346	20,275,355
Sale of energy		123,841,401	109,210,947
Total revenue	15	144,407,747	129,486,302
Operating expenses			
Operating expenses	16	10,358,441	10,081,958
Depreciation and amortization		4,314,877	4,100,681
Loss on disposal of property, plant and equipment		484,742	49,291
		15,158,060	14,231,930
Cost of power purchased		123,409,715	106,666,165
		138,567,775	120,898,095
Income from operating activities		5,839,972	8,588,207
Finance income	17	84,388	197,471
Finance costs	17	(2,763,581)	(2,866,800)
Unrealized loss on fair value of derivatives	12	(1,375,956)	–
Income before income taxes		1,784,823	5,918,878
Income tax expense	9	(287,670)	(721,235)
		1,497,153	5,197,643
Net movement in regulatory balances net of tax			
Net movement in regulatory balances		(764,958)	(2,787,426)
Income tax		424,151	(412,248)
	10	(340,807)	(3,199,674)
Net income for the year and net movement in regulatory balances		**1,156,346**	**1,997,969**
Other comprehensive income			
Items that will not be reclassed to profit of loss			
Remeasurements of post-employment benefits		(133,500)	–
Tax on remeasurements		35,366	–
Other comprehensive loss for the year		(98,134)	–
Total comprehensive income for the year		$ **1,058,212**	$ **1,997,969**

See accompanying notes to the financial statements.

MILTON HYDRO DISTRIBUTION INC.

Statements of Changes in Equity

Year ended December 31, 2020, with comparative information for 2019

	Share capital	Retained earnings	Accumulated other comprehensive loss	Total
Balance at January 1, 2020	$ 17,008,908	$ 28,246,776	$ (113,119)	$ 45,142,565
Net income and net movement in regulatory balances	–	1,156,346	–	1,156,346
Other comprehensive loss	–	–	(98,134)	(98,134)
Dividends	–	(1,500,000)	–	(1,500,000)
Balance at December 31, 2020	$ 17,008,908	$ 27,903,122	$ (211,253)	$ 44,700,777
Balance at January 1, 2019	$ 17,008,908	$ 27,748,807	$ (113,119)	$ 44,644,596
Net income and net movement in regulatory balances	–	1,997,969	–	1,997,969
Dividends	–	(1,500,000)	–	(1,500,000)
Balance at December 31, 2019	$ 17,008,908	$ 28,246,776	$ (113,119)	$ 45,142,565

See accompanying notes to the financial statements.

MILTON HYDRO DISTRIBUTION INC.

Statement of Cash Flows

Year ended December 31, 2020, with comparative information for 2019

	2020	2019
Operating activities		
Net Income and net movement in regulatory balances	$ 1,156,346	$ 1,997,969
Adjustments for:		
Depreciation and amortization	4,634,559	4,413,215
Unrealized loss on fair value of derivative	1,375,956	–
Amortization of deferred revenue	(484,446)	(431,291)
Post-employment benefits	159,883	13,361
Remeasurements of post-employment benefits, net of tax	(98,134)	–
Losses on disposal of property, plant and equipment	484,742	49,291
Contributions received from customers	2,824,366	2,025,360
Net finance costs	2,679,193	2,669,329
Income tax expense	252,304	721,235
Change in non-cash operating working capital:		
Accounts receivable	(2,129,846)	(1,543,706)
Due to/from related parties	122,423	197,114
Unbilled revenue	139,868	180,622
Materials and supplies	47,813	(179,829)
Prepaid expenses	(84,778)	207,430
Accounts payable and accrued liabilities	(1,852,062)	1,978,951
Customer deposits	(33,720)	90,072
	9,194,467	12,389,123
Regulatory balances	340,807	3,199,674
Income tax paid	(2,200,644)	(274,452)
Income tax received	177,694	158,369
Interest paid	(2,763,581)	(2,866,800)
Interest received	84,388	197,471
Net cash from operating activities	4,833,131	12,803,385
Investing activities		
Purchase of property, plant and equipment	(10,171,210)	(9,666,706)
Proceeds on disposal of property, plant and equipment	140,118	242,953
Purchase of intangible assets	(186,718)	(2,172,340)
Long-term deposits		-
Net cash used by investing activities	(10,217,810)	(11,596,093)
Financing activities		
Dividends paid	(1,500,000)	(1,500,000)
Proceeds from long-term debt	4,000,000	4,000,000
Repayment of long-term debt	(1,570,314)	(1,405,665)
Net cash from financing activities	929,686	1,094,335
Change in cash and cash equivalents	(4,454,993)	2,301,627
Cash and cash equivalents, beginning of year	10,676,206	8,374,579
Cash and cash equivalents, end of year	$ 6,221,213	$ 10,676,206

See accompanying notes to the financial statements.

1. Reporting entity

Milton Hydro Distribution Inc. (the “Corporation”) is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Town of Milton (the “Town”). The address of the Corporation’s registered office is 200 Chisholm Drive, Milton, ON, L9T 3G9.

The Corporation delivers electricity and related energy services to residential and commercial customers in Milton. The Corporation is wholly owned by Milton Hydro Holdings Inc. and the ultimate parent company is the Town. The operations of the Corporation are regulated by the Ontario Energy Board (“OEB”).

The financial statements are for the Corporation as at and for the year ended December 31, 2020.

2. Basis of presentation

(a) Statement of compliance

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”).

The financial statements were approved by the Board of Directors on April 26, 2021.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency.

(d) Use of estimates and judgments

(i) Assumptions and estimation uncertainty

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

2. Basis of presentation (continued)

(d) Use of estimates and judgments (continued)

(i) Assumptions and estimation uncertainty (continued)

Information about assumptions and estimation uncertainties that have a significant risk of resulting in a material adjustment is included in the following notes:

(i) Note 3(b) – measurement of unbilled revenue
(ii) Notes 3(d), 3(e), 7 and 8 – estimation of useful lives of its property, plant and equipment and intangible assets
(iii) Notes 3(i) and 10 – recognition and measurement of regulatory balances
(iv) Notes 3(j) and 13 – measurement of defined benefit obligations: key actuarial assumptions
(v) Note 3(h) and 18 – recognition and measurement of provisions and contingencies
(vi) Note 3(m) and 9 – classification of taxes between current and deferred

(ii) Judgments

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following notes:

(i) Note 3(b) – determination of the performance obligation for contributions from customers and the related amortization period.
(ii) Note 3(k) – leases; whether an arrangement contains a lease

(e) Rate regulation

The Corporation is regulated by the OEB, under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies (“LDCs”), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

2. Basis of presentation (continued)

(e) Rate regulation (continued)

Rate setting

Distribution revenue

For distribution revenue, the Corporation files a Cost of Service ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and the OEB approves rates based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application in August 2015 which was approved for rates effective May 1, 2016 and implemented September 1, 2016.

Electricity rates

The OEB typically sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

In 2020, the OEB also adjusted the Regulated Price Plan (RPP) prices in March and June in response to the Government issued Emergency Orders under the *Emergency Management and Civil Protection Act* to assist Ontarians who were forced to stay home due to the COVID-19 pandemic. All remaining consumers pay the market price for electricity.

Distribution rate design for the Residential Class of customers is based on fully fixed rates, whereas distribution rate design for other classes of customers is based on a rate structure that is based on a monthly fixed service charge and a volumetric distribution charge based on either kWh's or kW's depending on the class the customer belongs to.

3. Significant accounting policies

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments

All financial assets and all financial liabilities are recognized initially at fair value plus any directly attributable costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(f). The Corporation does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

(b) Revenue recognition

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered. Amounts received in advance are presented in deferred revenue.

Capital contributions

Developers are required to contribute toward the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 *Revenue from Contracts with Customers*. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

3. Significant accounting policies (continued)

(b) Revenue recognition (continued)

Capital contributions (continued)

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 *Revenue from Contracts with Customers*. The contributions are received to obtain a connection to the distribution system in order to receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

Government grants and the related performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies

Materials and supplies, the majority of which are consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

(d) Property, plant and equipment

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of six months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

3. Significant accounting policies (continued)

(d) Property, plant and equipment (continued)

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

Buildings	50 years
Distribution equipment	15-45 years
Other PP&E	5-20 years

(e) Intangible assets

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments for capital contributions under capital cost recovery agreements are classified as intangible assets. These include payments made for right of use for transformer stations for which the Corporation does not hold title. These rights are measured at cost less accumulated amortization.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

Computer software	5 - 10 years
Capital cost recovery agreement rights	25 years

3. Significant accounting policies (continued)

(f) Impairment

(i) Financial assets measured at amortized cost

A loss provision for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss provision is measured at an amount equal to the lifetime expected credit losses for the asset. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

(ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(g) Customer deposits

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

3. Significant accounting policies (continued)

(h) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(i) Regulatory balances

Regulatory debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

(j) Post-employment benefits

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

3. Significant accounting policies (continued)

(j) Post-employment benefits (continued)

(i) Pension plan (continued)

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides its retired employees with life insurance benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Remeasurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

(k) Leased assets

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

3. Significant accounting policies (continued)

(k) Leased assets (continued)

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

(l) Finance income and finance costs

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents.

Finance costs comprise interest paid on borrowings and customer deposits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) Income taxes

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

3. Significant accounting policies (continued)

(m) Income taxes (continued)

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

4. Cash and cash equivalents

Cash and cash equivalents consist of bank balances in excess of outstanding cheques issued and not cashed.

5. Accounts receivable

	2020	2019
Trade receivables	$ 8,388,553	$ 7,403,963
Less: allowance for impairment	(143,863)	(84,369)
	8,244,690	7,319,594
Provincial rebates and other receivables	4,176,247	2,986,038
Billable work	153,886	139,345
	$12,574,823	$10,444,977

6. Materials and supplies

No amounts were written down due to obsolescence in 2020 or 2019.

7. Property, plant and equipment

	Land and buildings	Distribution equipment	Other PP&E	Construction -in-progress	Total
Cost or deemed cost					
Balance at January 1, 2020	$14,847,632	$ 97,050,251	$ 7,292,729	$ 3,733,732	$122,924,344
Additions	30,135	5,399,604	355,688	4,385,783	10,171,210
Transfers	–	3,733,732	–	(3,733,732)	–
Disposals/retirements	–	(1,831,888)	–	–	(1,831,888)
Balance at December 31, 2020	$14,877,767	$ 104,351,699	$ 7,648,417	$ 4,385,783	$131,263,666
Balance at January 1, 2019	$14,483,412	$ 89,949,879	$ 6,505,573	$ 2,660,656	$113,599,520
Additions	364,220	5,697,898	870,856	3,733,732	10,666,706
Transfers	–	2,660,656	–	(2,660,656)	–
Disposals/retirements	–	(1,258,182)	(83,700)	–	(1,341,882)
Balance at December 31, 2019	$14,847,632	$ 97,050,251	$ 7,292,729	$ 3,733,732	$122,924,344
Accumulated depreciation					
Balance at January 1, 2020	$ 899,058	$ 10,789,999	$ 2,681,144	$ –	$ 14,370,201
Depreciation	216,897	3,332,200	673,228	–	4,222,325
Disposals/retirements	–	(1,207,029)	–	–	(1,207,029)
Balance at December 31, 2020	$ 1,115,955	$ 12,915,170	$ 3,354,372	$ –	$ 17,385,497
Balance at January 1, 2019	$ 682,823	$ 8,604,344	$ 2,107,363	$ –	$ 11,394,530
Depreciation	216,235	3,157,509	651,564	–	4,025,308
Disposals/retirements	–	(971,854)	(77,783)	–	(1,049,637)
Balance at December 31, 2019	$ 899,058	$ 10,789,999	$ 2,681,144	$ –	$ 14,370,201
Carrying amounts					
At December 31, 2020	$13,761,812	$ 91,436,529	$ 4,294,045	$ 4,385,783	$113,878,169
At December 31, 2019	$13,948,574	$ 86,260,252	$ 4,611,585	$ 3,733,732	$108,554,143

At December 31, 2020, PP&E with carrying amounts of $113,878,169 (2019 - $108,554,143) are subject to a general security agreement relating to the Corporation’s debt.

8. Intangible assets

	Computer software	Capital cost recovery agreement rights	Total
Cost or deemed cost			
Balance at January 1, 2020	$ 2,256,532	$ 2,085,817	$ 4,342,349
Additions	70,826	115,892	186,718
Balance at December 31, 2020	$ 2,327,358	$ 2,201,709	$ 4,529,067
Balance at January 1, 2019	$ 2,049,184	$ 120,825	$ 2,170,009
Additions	207,348	1,964,992	2,172,340
Balance at December 31, 2019	$ 2,256,532	$ 2,085,817	$ 4,342,349
Accumulated amortization			
Balance at January 1, 2020	$ 1,343,734	$ 42,916	$ 1,386,650
Amortization	357,116	55,118	412,234
Balance at December 31, 2020	$ 1,700,850	$ 98,034	$ 1,798,884
Balance at January 1, 2019	$ 983,448	$ 15,295	$ 998,743
Amortization	360,286	27,621	387,907
Balance at December 31, 2019	$ 1,343,734	$ 42,916	$ 1,386,650
Carrying amounts			
At December 31, 2020	$ 626,508	$ 2,103,675	$ 2,730,183
At December 31, 2019	912,798	2,042,901	2,955,699

9. Income tax expense

Current tax expense

	2020	2019
Current year	$ 333,817	$ 643,630
Adjustment for prior years	62,960	916,679
	$ 396,777	$ 1,560,309

Deferred tax expense

	2020	2019
Origination and reversal of temporary differences	$ (109,107)	$ (839,074)
Tax adjustment included in other comprehensive income	(35,366)	–
	$ (144,473)	$ (839,074)

Reconciliation of effective tax rate

	2020	2019
Income before taxes	$ 1,784,823	$ 5,918,878
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected income tax recovery on income at statutory rates	472,978	1,568,503
Increase (decrease) in income taxes resulting from:		
Permanent differences	531	49,936
Regulatory movements	(202,714)	(784,722)
Other	16,875	(112,482)
Income tax expense	$ 287,670	$ 721,235

Significant components of the Corporation's deferred tax balances

	2020	2019
Deferred tax assets (liabilities):		
Property, plant and equipment	$ (8,576,468)	$ (7,628,018)
Post-employment benefits	177,497	135,128
Deferred revenue	4,809,406	4,327,476
Unrealized derivative	364,628	–
Other	379,552	175,556
	$ (2,845,385)	$ (2,989,858)

10. Regulatory balances

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory asset balances	January 1, 2020	Additions	Recovery/ reversal	Transfers	December 31, 2020	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 2,090,110	$ (67,767)	$ –	$ –	$ 2,022,343	2-3
Regulatory settlement account	3,232,197	–	133,129	(529,513)	2,835,813	–
Regulatory transition to IFRS	348,207	–	–	–	348,207	2-3
Other regulatory accounts	306,400	436,602	–	–	743,002	2-3
Income tax	3,165,416	424,151	–	–	3,589,567	*
	$ 9,142,330	$ 792,986	$ 133,129	$ (529,513)	$ 9,538,932	

Regulatory asset balances	January 1, 2019	Additions	Recovery/ reversal	Transfers	December 31, 2019	Remaining recovery/ reversal years
Group 1 deferred accounts	$ 3,958,139	$ –	$ (1,868,029)	$ –	$ 2,090,110	2-3
Regulatory settlement account	8,785,917	(7,055,925)	–	1,502,205	3,232,197	–
Regulatory transition to IFRS	348,207	–	–	–	348,207	2-3
Other regulatory accounts	399,369	–	(92,969)	–	306,400	2-3
Income tax	3,577,664	(412,248)	–	–	3,165,416	*
	$17,069,296	$ (7,468,173)	$ (1,960,998)	$ 1,502,205	$ 9,142,330	

Regulatory liability balances	January 1, 2020	Additions	Recovery/ reversal	Transfers	December 31, 2020	Remaining years
Group 1 deferred accounts	$ (3,052,383)	$ (227,205)	$ –	$ –	$ (3,279,588)	2-3
Regulatory settlement account	(2,914,346)	–	(515,321)	529,513	(2,900,154)	1
Other regulatory accounts	(503,708)	(524,396)	–	–	(1,028,104)	2-3
	$ (6,470,437)	$ (751,601)	$ (515,321)	$ 529,513	$ (7,207,846)	

Regulatory liability balances	January 1, 2019	Additions	Recovery/ reversal	Transfers	December 31, 2019	Remaining years
Group 1 deferred accounts	$ (2,279,837)	$ (1,413,823)	$ 641,277	$ –	$ (3,052,383)	2-3
Regulatory settlement account	(8,825,655)	7,413,514	–	(1,502,205)	(2,914,346)	1
Other regulatory accounts	(92,237)	(411,471)	–	–	(503,708)	2-3
	$(11,197,729)	$ 5,588,220	$ 641,277	$ (1,502,205)	$ (6,470,437)	

* These balances will reverse as the related deferred tax balance reverses.

10. Regulatory balances (continued)

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. The Corporation has received approval from the OEB to establish its regulatory account balances.

Settlement of the Group 1 deferral accounts is done on an annual basis through application to the OEB. Settlement of Group 2 deferral accounts is done at the time of filing a COS Rate Application to the OEB. An application has been approved by the OEB to recover the Group 1 deferral accounts as at December 31, 2017 beginning May 1, 2019. The approved account balances have been moved to the regulatory settlement account. The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory asset for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation’s deferred tax balance fluctuates.

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers’ Acceptances three-month rate plus a spread of 25 basis points. In 2020 the prescribed interest rate was between .57% and 2.18%.

On April 16, 2020, the OEB approved a rate increase for rates effective May 1, 2020. On April 16, 2020, the OEB gave the Corporation the option to defer this rate increase to November 1, 2020 due to the COVID-19 outbreak and pandemic. The Corporation decided not to defer this rate increase and it implemented the rates as approved by the OEB on May 1, 2020.

The OEB has a decision and order in place banning LDC's in Ontario from disconnecting homes for non-payment during the winter. This ban is normally in place from November 15 to April 30 each year but was extended during the year to July 31, 2020.

11. Accounts payable and accrued liabilities

	2020	2019
Accounts payable – energy purchases	$ 3,734,713	$ 7,996,597
Payroll payable	461,807	435,522
Interest payable	367,369	382,675
Other	11,918,508	9,519,665
	$ 16,482,397	$ 18,334,459

12. Long-term debt

	2020	2019
Note payable to Town of Milton	$ 14,934,210	$ 14,934,210
Other loans:		
Interest bearing at 4.49%, payable in blended semi-annual payments of $132,967, maturing April 1, 2025	1,072,725	1,283,373
Interest bearing at 4.84%, payable in blended semi-annual payments of $138,786 maturing July 15, 2035	2,936,068	3,066,771
Interest bearing at 4.33%, payable in blended semi-annual payments of $114,858 maturing September 15, 2036	2,631,991	2,744,088
Interest bearing at 3.92%, payable in blended semi-annual payments of $80,468 maturing February 16, 2037	1,941,889	2,024,274
Interest bearing at 3.87%, payable in blended semi-annual payments of $80,044 maturing September 17, 2037	1,980,619	2,061,697
Interest bearing at 3.74%, payable in blended semi-annual payments of $94,242 maturing May 3, 2038	2,404,658	2,500,510
Interest bearing at 3.97%, payable in blended semi-annual payments of $123,719 maturing July 15, 2039	3,279,484	3,393,326
Interest bearing at 3.04%, payable in blended semi-annual payments of $223,845 maturing March 16, 2040	6,549,706	6,792,731
Interest bearing at 3.55%, payable in blended semi-annual payments of $121,345 maturing July 1, 2040	3,454,352	3,571,293
Interest bearing at 3.31%, payable in blended semi-annual payments of $38,427 maturing September 1, 2040	1,117,709	1,156,600
Interest bearing at 3.58%, payable in blended monthly payments of $18,140 maturing December 22, 2045	4,052,000	3,680,159
Interest bearing at 3.74%, payable in blended monthly payments of $13,876 maturing December 15, 2046	2,766,029	2,827,838
Interest bearing at 3.90%, payable in blended monthly payments of $18,867 maturing July 1, 2048	4,521,889	3,897,630
Interest bearing at 3.15%, payable in blended monthly payments of $12,886 maturing October 4, 2049	3,145,255	2,989,946
Interest bearing at 3.10%, payable in blended monthly payments of $4,270 maturing December 16, 2049	979,468	1,000,000
Interest bearing at 2.35%, payable in blended monthly payments of $15,495 maturing July 6, 2050	3,962,036	–
	61,730,088	57,924,446
Less: current portion of long-term debt	(1,686,013)	(1,532,350)
	$ 60,044,075	$ 56,392,096

12. Long-term debt (continued)

The note payable to the Town of Milton bears interest at 7.25% and is due on demand. The Town has waived its right to demand payment on or before January 1, 2022.

In conjunction with the $4,052,000, $4,521,889 and $3,145,255 facilities, the Corporation entered into an interest rate swap arrangement in prior years. The interest rate on the three facilities is variable and its risk has been mitigated through the entering of a swap agreement. The fair value of the interest rate swap agreement is based on amounts quoted by the Corporation's financial institution taking into account interest rates at December 31, 2020. The interest rate swap agreement is in a net unfavourable position of $1,375,956 ($459,206, $699,997 and $216,753 respectively). The Corporation has not applied hedge accounting and the associated unrealized losses are included in the statement of comprehensive income.

The other loans have various maturity dates and interest rates of between 2.35% and 4.84% per annum. The other loans are secured by a general security agreement over all of the assets of the Corporation.

Certain financial liabilities are subject to financial covenants and the covenants are meet as of yearend.

Scheduled repayments of long-term debt for the years ended December 31 are as follows:

2021	$ 1,686,013
2022	1,749,914
2023	1,816,581
2024	1,885,622
2025	1,824,886
2026 and thereafter	52,767,071
	$ 61,730,088

13. Post-employment benefits

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2020, the Corporation made employer contributions of $519,139 to OMERS (2019 - $482,659), of which $97,085 (2019 - $126,337) has been capitalized as part of PP&E and the remaining amount of $422,054 (2019 - $356,322) has been recognized in profit or loss. The Corporation estimates that a contribution of $600,730 to OMERS will be made during the next fiscal year.

As at December 31, 2020, OMERS had approximately 526,000 members, of whom 51 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2020, which reported that the plan was 97% funded.

13. Post-employment benefits (continued)

(b) Post-employment benefits other than pension

The Corporation pays certain life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and remeasurements recognized for post-employment benefit plans.

Reconciliation of the obligation	2020	2019
Defined benefit obligation, beginning of year	$ 509,917	$ 496,556
Included in profit or loss		
Current service cost	11,500	11,837
Interest cost	17,800	17,107
	29,300	28,944
Included in other comprehensive income		
Actuarial losses	133,500	–
Benefits paid	(2,917)	(15,583)
Defined benefit obligation, end of year	$ 669,800	$ 509,917

(b) Post-employment benefits other than pension (continued)

Actuarial assumptions	2020	2019
General inflation	2.00%	2.00%
Discount rate	2.50%	3.50%
Salary levels	2.75%	3.20%

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $135,700 (2019 - $92,200). A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $190,700 (2019 - $123,900).

14. Share capital

	2020	2019
Authorized:		
Unlimited number of common shares		
Issued:		
2,000 common shares	$ 17,008,908	$ 17,008,908

Dividends

The holders of the common shares are entitled to receive dividends as declared from time to time.

The Corporation paid aggregate dividends in the year on common shares of $750 per share (2019 - $750), which amount to total dividends paid in the year of $1,500,00 (2019 - $1,500,000).

15. Revenue

	2020	2019
Distribution revenue	$ 18,556,556	$ 18,203,473
Sales of energy	123,841,401	109,210,947
Rendering services	517,460	675,826
Water and wastewater billing	750,371	717,563
Revenue from contracts with customers	143,665,788	128,807,809
Amortization of deferred revenue	484,446	431,291
Miscellaneous other revenue	257,513	247,202
Total revenue	144,407,747	129,486,302
Revenue from contracts with customers:		
Residential	65,478,506	49,748,592
General service	61,826,233	61,647,886
Commercial	750,371	717,563
Large user	14,545,439	15,237,950
Other	1,065,239	1,455,818
	$ 143,665,788	$ 128,807,809

16. Operating expenses

	2020	2019
Salaries and benefits	$ 5,513,244	$ 5,147,909
Contract/consulting	3,032,458	2,936,478
Materials and supplies	429,504	520,615
Vehicles	191,347	163,062
Leases of equipment	5,542	5,262
Other	1,186,346	1,308,632
	$ 10,358,441	$ 10,081,958

17. Finance income and costs

	2020	2019
Finance income		
Interest income on bank deposits	$ 84,388	$ 197,471
Finance costs		
Interest expense on long-term debt	2,688,472	2,595,307
Interest expense on customer deposits	25,944	70,379
Other	49,165	201,114
	2,763,581	2,866,800
Net finance costs recognized in profit or loss	$ (2,679,193)	$ (2,669,329)

18. Commitments and contingencies

General

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2020, no assessments have been made.

19. Operating leases

The Corporation is committed to lease agreements for various equipment of low value. The Corporation is currently committed to a photocopier lease agreement.

The future minimum non-cancellable annual lease payments are due as follows:

	2020	2019
Between one and five years	$ 15,269	$ 11,840

During the year ended December 31, 2020, an expense of $6,014 (2019 - $5,262) was recognized in net income in respect of these low value operating leases.

20. Related party transactions

(a) Parent and ultimate controlling party

The sole shareholder of the Corporation is Milton Hydro Holdings Inc., which in turn is wholly-owned by the Town. The Town produces consolidated financial statements of Milton Hydro Holdings Inc. that are available to the public.

(b) Outstanding balances with related parties

	2020	2019
Due from (to) related parties		
Parent company	$ 153,997	$ 145,318
Affiliated companies	(354,895)	(223,793)
	(200,898)	(78,475)
Intercompany promissory note receivable	350,000	350,000
Town of Milton (in accounts receivable)	343,602	390,100
	$ 492,704	$ 661,625

On December 23, 2015, the Corporation issued a promissory note for $350,000 (2019 - $350,000) at the rate of 1.90% per annum to Milton Energy and Generation Solutions Inc. Interest shall be calculated and payable on a semi-annual basis on the last day of June and December. The promissory note is callable at the discretion of the Corporation.

The amounts due from the Town are regular receivables and as such are included in accounts receivable and are non-interest bearing with no fixed terms of repayment.

(c) Transactions with parent

During the year, the Corporation paid management and business development fees to its parent in the amount of $97,280 (2019 - $103,561).

20. Related party transactions (continued)

(d) Transactions with ultimate parent (the Town)

The Corporation had the following transactions with its ultimate parent, a government entity:

In the ordinary course of business, the Corporation delivers electricity to the Town. During the year, the Corporation earned gross revenue of $3,142,541 (2019 - $3,280,704) from the Town. Of this amount, $414,383 (2019 - $436,902) was net distribution revenue. Electricity delivery charges are at prices and under terms approved by the OEB.

(e) Key management personnel

The key management personnel of the Corporation have been defined as the executive management team members and board of directors. The compensation paid or payable is as follows:

	2020	2019
Total compensation	$ 1,368,916	$ 1,224,518

21. Financial instruments and risk management

Fair value disclosure

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt at December 31, 2020 is $69,631,000. The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rates used to calculate fair value at December 31, 2020 range from 3.04% to 4.84%, depending on the maturity of the debt.

Financial risks

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation’s exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

(a) Credit risk

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Town of Milton. No single customer account has a balance in excess of 5.8% of total accounts receivable.

21. Financial instruments and risk management (continued)

Financial risks (continued)

(a) Credit risk (continued)

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the allowance for impairment at December 31, 2020 is $143,863 (2019 - $84,369). An impairment loss of $129,672 (2019 - $130,122) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2020, approximately $353,906 (2019 - $204,054) is considered 45 days past due. The Corporation has over 40,000 customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from general service customers in accordance with directions provided by the OEB and through credit insurance. As at December 31, 2020, the Corporation holds security deposits in the amount of $3,667,344 (2019 - $3,701,064).

(b) Market risk

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

(c) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $4 million credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2020, no amounts had been drawn under the Corporation's credit facility. Amounts drawn are due on demand.

The Corporation also has a bilateral facility for $3 million (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $2.9 million (2019 - $2.9 million) has been drawn and posted with the IESO.

The majority of accounts payable, as reported on the statement of financial position, are due within 15 days.

21. Financial instruments and risk management (continued)

Financial risks (continued)

(d) Capital disclosures

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2020, shareholder's equity amounts to $44,700,777 (2019 - $45,142,565) and long-term debt due beyond one year amounts to $60,044,075 (2019 - $56,392,096).

22. COVID-19

During the year ended December 31, 2020, the COVID-19 outbreak was declared a pandemic by the World Health Organization. This has resulted in governments worldwide, including the Canadian and Ontario governments, enacting emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally and in Ontario resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions however the success of these interventions is not currently determinable. The current challenging economic climate may lead to adverse changes in cash flows, working capital levels and/or debt balances, which may also have a direct impact on the Corporation's operating results and financial position in the future. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and our business are not known at this time.

23. Comparative information

Certain comparative information has been reclassified to conform with the financial statement presentation adopted in the current year.

Schedule of Instalment Remittances

Name of corporation contact: Igor Rusic
Telephone number: (905) 876-4611

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	692,388

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 692,388 **A**

Total instalments credited to the taxation year per T9 692,388 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			1,058,212	A
Add:				
Provision for income taxes – current	101	396,777		
Provision for income taxes – deferred	102	-109,107		
Amortization of tangible assets	104	4,634,559		
Loss on disposal of assets	111	484,742		
Charitable donations and gifts from Schedule 2	112	4,000		
Non-deductible meals and entertainment expenses	121	2,003		
Reserves from financial statements – balance at the end of the year	126	669,800		
Subtotal of additions		6,082,774	6,082,774	

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Inducement under 12(1)(x) ITA	2,690
2	Section 12(1)(a) income	6,722,937
3	Capital contributions received 12(1)(x)	2,303,048
4	Closing regulatory balance (credit)	1,432,269
5	Unrealized loss on fair value derivatives	1,375,956
	Total of column 2	11,836,900

Total of column 2	296	11,836,900		
Subtotal of other additions	199	11,836,900	11,836,900	D
Total additions	500	17,919,674	17,919,674	
Amount A **plus** line 500			18,977,886	B
Deduct:				
Capital cost allowance from Schedule 8	403	6,545,265		
Reserves from financial statements – balance at the beginning of the year	414	509,917		
Contributions to deferred income plans from Schedule 15	417	97,085		
Subtotal of deductions		7,152,267	7,152,267	

Other deductions:

Non-taxable/deductible other comprehensive income items	347	35,366

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Section 20(1)(m) reserve	6,722,937
2	Amortization of deferred capital contributions	484,446
3	ITA 13(7.4) Election - capital contributions received	2,303,048
4	Tax recovery included in regulatory movement	424,151
5	Opening regulatory balance (credit)	667,311
	Total of column 2	10,601,893

Total of column 2	396	10,601,893

Subtotal of other deductions	499	10,637,259 ▶	10,637,259	E
Total deductions	510	17,789,526 ▶	17,789,526	
Net income (loss) for income tax purposes (amount B **minus** line 510)			1,188,360	C

Enter amount C on line 300 of the T2 return.

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Description	Operator (Note)	Amount	
Customer deposits - current		3,667,344	00
Customer deposits - non-current	+	3,055,593	00
	+		
	Total	6,722,937	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Federal

A		
X	Investment tax credit from apprenticeship job creation expenditures	1,854
X	Investment tax credit from child care spaces expenditures	
	Canadian film or video production tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
	Film or video production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
X	Investment tax credit claimed on contributions made to SR&ED farming organizations	
	Canadian journalism labour tax credit	
	Canada emergency wage subsidy (CEWS), Canada emergency rent subsidy (CERS) and other taxable amounts from COVID-19 programs*	

* The amount entered in this field is transferred to the **Miscellaneous other additions** section of Schedule 1 on the line of column 295 associated with line 4, **Taxable amounts from COVID-19 programs**, of column 605.

Ontario

A		
X	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
X	Ontario co-operative education tax credit	
X	Ontario apprenticeship training tax credit	836
	Ontario computer animation and special effects tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
	Ontario film and television tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
	Ontario production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
	Ontario interactive digital media tax credit* * Please verify if the credit amount relates to depreciable property. For more information, consult the Help (F1).	
	Ontario book publishing tax credit	
X	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
	Ontario business-research institute tax credit	
	Ontario community food program donation tax credit for farmers	

Tax credits whose amount should reduce the capital cost of property

Canada Revenue Agency / Agence du revenu du Canada

Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers
  - the eligible amount of gifts of certified cultural property
  - the eligible amount of gifts of certified ecologically sensitive land or
  - the additional deduction for gifts of medicine made before March 22, 2017
- All legislative references are to the federal Income Tax Act, unless stated otherwise.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts can be carried forward for 5 years except for gifts of certified ecologically sensitive land made after February 10, 2014, which can be carried forward for 10 years.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift made before March 22, 2017, to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File this schedule with your T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
Salvation Army	4,000
Subtotal	4,000
Add: Total donations of less than $100 each	
Total donations in current tax year	4,000

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year			1A		
Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year (amount 1A **minus** line 239)	240				
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1, Net Income (Loss) for Income Tax Purposes)	210	4,000		4,000	4,000
Subtotal (line 250 **plus** line 210)		4,000	1B	4,000	4,000
Subtotal (line 240 **plus** amount 1B)		4,000	1C	4,000	4,000
Adjustment for an acquisition of control	255				
Total charitable donations available (amount 1C **minus** line 255)		4,000	1D	4,000	4,000
Amount applied in the current year against taxable income (cannot be more than amount 2H in Part 2) (enter this amount on line 311 of the T2 return)	260	4,000		4,000	4,000
Charitable donations closing balance (amount 1D **minus** line 260)	280				

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) . . . . **262** ____________

Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %) . . . . ____________ 1

Enter amount 1 on line 420 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the Taxation Act, 2007 (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) . . . . **263** ____________

Nova Scotia food bank tax credit for farmers (amount on line 263 **multiplied** by 25 %) . . . . ____________ 2

Enter amount 2 on line 570 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia Income Tax Act.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016, and before January 1, 2024) . . . . **265** ____________

British Columbia farmers' food donation tax credit (amount on line 265 **multiplied** by 25 %) . . . . ____________ 3

Enter amount 3 on line 683 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia Income Tax Act.

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2019-12-31			
2nd prior year	2018-12-31			
3rd prior year	2017-12-31			
4th prior year	2016-12-31			
5th prior year	2015-12-31			
6th prior year*	2014-12-31			
7th prior year	2013-12-31			
8th prior year	2012-12-31			
9th prior year	2011-12-31			
10th prior year	2010-12-31			
11th prior year	2009-12-31			
12th prior year	2008-12-31			
13th prior year	2007-12-31			
14th prior year	2006-12-31			
15th prior year	2005-12-31			
16th prior year	2004-12-31			
17th prior year	2003-12-31			
18th prior year	2002-12-31			
19th prior year	2001-12-31			
20th prior year	2001-09-30			
21st prior year*	2000-09-30			
Total (to line A)				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes Note 1 **multiplied** by 75 % 891,270 2A

Taxable capital gains arising in respect of gifts of capital property included in Part 1 Note 2 ..... **225** ________

Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01) .... **227** ________

The amount of the recapture of capital cost allowance in respect of charitable donations .... **230** ________

Proceeds of disposition, **less** outlays and expenses Note 2 .... ________ 2B

Capital cost Note 2 .... ________ 2C

Amount 2B or 2C, whichever is less .... **235** ________

Amount on line 230 or 235, whichever is less .... ________ 2D

Subtotal (**add** lines 225, 227, and amount 2D) ________ 2E

Amount 2E **multiplied** by 25 % ________ 2F

Subtotal (amount 2A **plus** amount 2F) 891,270 2G

Maximum allowable deduction for charitable donations
(enter amount 1D from Part 1, amount 2G, or net income for tax purposes, whichever is the least) 4,000 2H

Note 1: For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

Note 2: This amount must be prorated by the following calculation, eligible amount of the gift **divided** by the proceeds of disposition of the gift.

Part 3 – Gifts of certified cultural property

	Line	Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			3A		
Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year (amount 3A **minus** line 439)	440				
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			3B		
Subtotal (line 440 **plus** amount 3B)			3C		
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			3D		
Gifts of certified cultural property closing balance (amount 3C **minus** amount 3D)	480				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2019-12-31			
2nd prior year	2018-12-31			
3rd prior year	2017-12-31			
4th prior year	2016-12-31			
5th prior year	2015-12-31			
6th prior year*	2014-12-31			
7th prior year	2013-12-31			
8th prior year	2012-12-31			
9th prior year	2011-12-31			
10th prior year	2010-12-31			
11th prior year	2009-12-31			
12th prior year	2008-12-31			
13th prior year	2007-12-31			
14th prior year	2006-12-31			
15th prior year	2005-12-31			
16th prior year	2004-12-31			
17th prior year	2003-12-31			
18th prior year	2002-12-31			
19th prior year	2001-12-31			
20th prior year	2001-09-30			
21st prior year*	2000-09-30			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 4 – Gifts of certified ecologically sensitive land

		Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			4A		
Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount 4A **minus** line 539)	540				
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land (include this amount on line 112 of Schedule 1)	520				
Subtotal (line 550 **plus** line 520)			4B		
Subtotal (line 540 **plus** amount 4B)			4C		
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			4D		
Gifts of certified ecologically sensitive land closing balance (amount 4C **minus** amount 4D)	580				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date

Year of origin:		Federal	Québec	Alberta
1st prior year	2019-12-31			
2nd prior year	2018-12-31			
3rd prior year	2017-12-31			
4th prior year	2016-12-31			
5th prior year	2015-12-31			
6th prior year*	2014-12-31			
7th prior year	2013-12-31			
8th prior year	2012-12-31			
9th prior year	2011-12-31			
10th prior year	2010-12-31			
11th prior year*	2009-12-31			
12th prior year	2008-12-31			
13th prior year	2007-12-31			
14th prior year	2006-12-31			
15th prior year	2005-12-31			
16th prior year	2004-12-31			
17th prior year	2003-12-31			
18th prior year	2002-12-31			
19th prior year	2001-12-31			
20th prior year	2001-09-30			
21st prior year*	2000-09-30			
Total				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line *6th prior year* and gifts that are included on line *11th prior year* expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line *6th prior year* and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 5 – Additional deduction for gifts of medicine

		Federal		Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			5A		
Additional deduction for gifts of medicine expired after five tax years*	639				
Additional deduction for gifts of medicine at the beginning of the current tax year (amount 5A **minus** line 639)	640				
Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary	650				
Additional deduction for gifts of medicine made before March 22, 2017:					
Proceeds of disposition	602				
Cost of gifts of medicine made before March 22, 2017	601				
Subtotal (line 602 **minus** line 601)			5B		
Amount 5B **multiplied** by 50 %			5C		
Eligible amount of gifts	600				

Federal

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 **610** ______

Québec

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 ______

Alberta

a ______ x (b ______ / c) = Additional deduction for gifts of medicine made before March 22, 2017 ______

where:

a is the **lesser** of line 601 and amount 5C

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

		Federal		Québec	Alberta
Subtotal (line 650 **plus** line 610)			5D		
Subtotal (line 640 **plus** amount 5D)			5E		
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			5F		
Additional deduction for gifts of medicine closing balance (amount 5E **minus** amount 5F)	680				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2019-12-31			
2nd prior year	2018-12-31			
3rd prior year	2017-12-31			
4th prior year	2016-12-31			
5th prior year	2015-12-31			
6th prior year*	2014-12-31			
7th prior year	2013-12-31			
8th prior year	2012-12-31			
9th prior year	2011-12-31			
10th prior year	2010-12-31			
11th prior year	2009-12-31			
12th prior year	2008-12-31			
13th prior year	2007-12-31			
14th prior year	2006-12-31			
15th prior year	2005-12-31			
16th prior year	2004-12-31			
17th prior year	2003-12-31			
18th prior year	2002-12-31			
19th prior year	2001-12-31			
20th prior year	2001-09-30			
21st prior year*	2000-09-30			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income (enter this amount on line 255 of form CO-17)		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2019-12-31	
2nd prior year	2018-12-31	
3rd prior year	2017-12-31	
4th prior year	2016-12-31	
5th prior year	2015-12-31	
6th prior year*	2014-12-31	
7th prior year	2013-12-31	
8th prior year	2012-12-31	
9th prior year	2011-12-31	
10th prior year	2010-12-31	
11th prior year	2009-12-31	
12th prior year	2008-12-31	
13th prior year	2007-12-31	
14th prior year	2006-12-31	
15th prior year	2005-12-31	
16th prior year	2004-12-31	
17th prior year	2003-12-31	
18th prior year	2002-12-31	
19th prior year	2001-12-31	
20th prior year	2001-09-30	
21st prior year*	2000-09-30	
Total		

* These gifts expired in the current year.

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Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83
  - deductible dividends under subsection 138(6)
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (a.1), (b) or (d)
  - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3)
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations.
- A payer corporation is **connected** with a recipient corporation at any time in a tax year, if at that time the recipient corporation meets either of the following conditions:
  - it controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b)
  - it owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A1 – Enter "X" if dividends were received from a foreign source.
  Column F1 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H, I, I.1 and L **only if** the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing columns J, K and L use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business Number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYYMMDD 220	E Non-taxable dividends under section 83 230
1			2			
					Total of column E (enter amount on line 402 of Schedule 1)	

Part 1 – Dividends received in the tax year (continued)

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)[note 1] 240	F1	G Eligible dividends included in column F 242	H Total taxable dividends paid by **connected** payer corporation (for tax year in column D) 250
1				

	I Dividend refund of the **connected** payer corporation (for tax year in column D)[note 2] 260	I.1 Dividend refund of the **connected** payer corporation from its eligible refundable dividend tax on hand (ERDTOH) (for tax year in column D) [notes 2 and 5]	J Part IV tax for eligible dividends. Dividends (from column G) **multiplied** by 38 1/3%[note 3] 265	K Part IV tax before deductions. Dividends (from column F) **multiplied** by 38 1/3%[note 4] 275	L Part IV tax before deductions on taxable dividends received from **connected** corporations [notes 2 and 5] 280
1					

Total of column L (enter amount on line 2E in Part 2) ______

Taxable dividends received from connected corporations (total amounts from column F with code 1 in column B) . . . . ______ 1A

Taxable dividends received from non-connected corporations (total amounts from column F with code 2 in column B) . . . . ______ 1B

Subtotal (amount 1A **plus** amount 1B, include this amount on line 320 of the T2 return) ______ 1C

Eligible dividends received from connected corporations (total amounts from column G with code 1 in column B) . . . . ______ 1D

Eligible dividends received from non-connected corporations (total amounts from column G with code 2 in column B) . . . . ______ 1E

Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column K with code 1 in column B) . . . . ______ 1F

Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column K with code 2 in column B) . . . . ______ 1G

Subtotal (amount 1F **plus** amount 1G) ______ ▶ ______ 1H

Part IV tax on eligible dividends received from connected corporations (total amounts from column J with code 1 in column B) . . . . ______ 1I

Part IV tax on eligible dividends received from non-connected corporations (total amounts from column J with code 2 in column B) . . . . ______ 1J

Subtotal (amount 1I **plus** amount 1J) ______ ▶ ______ 1K

Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H **minus** amount 1K) . . . . ______ 1L

1 If taxable dividends are received, enter the amount in column F, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column J or column K whichever one applies. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable. For column L, you only have to estimate the payer's dividend refund from its eligible refundable dividend tax on hand (ERDTOH) (column I.1).

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column G.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column F.

5 For taxable dividends received from **connected** corporations (with a tax year starting **after 2018**), Part IV tax on dividends is equal to: column I.1 (total of amounts CC and II of the connected payer corporation (on page 7 of the T2 return)) **divided** by column H **multiplied** by column F. If there is no dividend refund to the connected payer corporation from its ERDTOH for paying the taxable dividends, line 280 is nil.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received before deductions (amount 1H in part 1)			2A	
Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43)	320			
Subtotal (amount 2A **minus** line 320)				2B
Current-year non-capital loss claimed to reduce Part IV tax	330			
Non-capital losses from previous years claimed to reduce Part IV tax	335			
Current-year farm loss claimed to reduce Part IV tax	340			
Farm losses from previous years claimed to reduce Part IV tax	345			
Total losses applied against Part IV tax (total of lines 330 to 345)			2C	
Amount 2C **multiplied** by 38 1 / 3 %				2D
Part IV tax payable (amount 2B **minus** amount 2D, if negative enter "0") (enter amount on line 712 of the T2 return)	360			

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax before deductions on taxable dividends received from connected corporations (total of column L in part 1)		2E
Amount 4A from Schedule 43		2F
Part IV tax payable on taxable dividends received from connected corporations (amount 2E **minus** amount 2F, if negative enter "0")		2G

(enter at amount L on page 7 of the T2 return)

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1)		2H
Amount 4C from Schedule 43		2I
Part IV tax payable on eligible dividends received from non-connected corporations (amount 2H **minus** amount 2I, if negative enter "0")		2J

(enter at amount M on page 7 of the T2 return)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	L Name of connected recipient corporation 400	M Business Number 410	N Tax year-end of connected recipient corporation in which the dividends in column O were received YYYYMMDD 420	O Taxable dividends paid to connected corporations 430	P Eligible dividends included in column O 440
1	MILTON HYDRO HOLDINGS INC.	86499 6764 RC0001	2020-12-31	1,500,000	
2					
				1,500,000 (Total of column O)	(Total of column P)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends included in line 450	455		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column O **plus** line 450)		460	1,500,000
Total eligible dividends paid in the tax year (total of column P **plus** line 455)		465	
Total non-eligible taxable dividends paid in the tax year (line 460 **minus** line 465)		470	1,500,000

Complete this part to determine the following amounts in order to calculate the dividend refund.

Line 465 **multiplied** by 38 1 / 3 % (enter at amount AA on page 7 of the T2 return)		3A
Line 470 **multiplied** by 38 1 / 3 % (enter at amount DD on page 7 of the T2 return)	575,000	3B

Part 4 – Total dividends paid in the tax year

Complete this part **if** the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			1,500,000	
Other dividends paid in the tax year (total of 510 to 540)				
Total dividends paid in the tax year		500	1,500,000	
Dividends paid out of capital dividend account	510			
Capital gains dividends	520			
Dividends paid on shares described in subsection 129(1.2)	530			
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540			
Subtotal (total of lines 510 to 540)		►		4A
Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount 4A)			1,500,000	4B

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- Use this schedule if, during the tax year, your corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B, and D in Part 1)
  - is claiming provincial or territorial tax credits or rebates (see Part 2), or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references are to the Income Tax Regulations.
- For more information, see the T2 Corporation – Income Tax Guide.
- For the regulation number to be entered in field 100 of Part 1, see the chart below.

Part 1 – Allocation of taxable income

100 ______ Enter the regulation that applies (402 to 413)

A Jurisdiction. Tick yes if your corporation had a permanent establishment in the jurisdiction during the tax year *		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue attributable to jurisdiction	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 Yes ☐	104		144		
Prince Edward Island	005 Yes ☐	105		145		
Nova Scotia	007 Yes ☐	107		147		
Nova Scotia Offshore	008 Yes ☐	108		148		
New Brunswick	009 Yes ☐	109		149		
Quebec	011 Yes ☐	111		151		
Ontario	013 Yes ☐	113		153		
Manitoba	015 Yes ☐	115		155		
Saskatchewan	017 Yes ☐	117		157		
Alberta	019 Yes ☐	119		159		
British Columbia	021 Yes ☐	121		161		
Yukon	023 Yes ☐	123		163		
Northwest Territories	025 Yes ☐	125		165		
Nunavut	026 Yes ☐	126		166		
Outside Canada	027 Yes ☐	127		167		
Total		129 G		169 H		

* **Permanent establishment** is defined in subsection 400(2)

** For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If your corporation has provincial or territorial tax payable, complete Part 2.
3. If your corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
1,184,360		1,184,360	136,201

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	136,201			
Ontario small business deduction (from Schedule 500)	402				
Subtotal (line 270 **minus** line 402)		136,201	▶	136,201	5A
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal (line 276 **plus** line 277)			▶		5B
Gross Ontario tax (amount 5A **plus** amount 5B)				136,201	5C
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario political contributions tax credit (from Schedule 525)	415				
Ontario non-refundable tax credits (total of lines 404 to 415)			▶		5D
Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0")				136,201	5E
Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0")				136,201	5F
Ontario corporate minimum tax credit (from Schedule 510)			418		
Ontario community food program donation tax credit for farmers (from Schedule 2)			420		
Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative, enter "0")				136,201	5G
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal (line 278 **plus** line 280)			▶		5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)				136,201	5I
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Ontario regional opportunities investment tax credit (from Schedule 570)	472				
Ontario refundable tax credits (total of lines 450 to 472)			▶		5J
Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets) Include this amount on line 255.			290	136,201	

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits . . . 255 136,201

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under Regulation 1101(5q)? **101** Yes [ ] No [X]

	1 Class number * See note 1 **200**	Description	2 Undepreciated capital cost (UCC) at the beginning of the year **201**	3 Cost of acquisitions during the year (new property must be available for use) See note 2 **203**	4 Cost of acquisitions from column 3 that are accelerated investment incentive properties (AIIP) or zero-emission vehicle (ZEV) See note 3 **225**	5 Adjustments and transfers See note 4 **205**	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition See note 5 **221**	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition See note 6 **222**	8 Proceeds of dispositions See note 7 **207**	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See note 8
1.	1		19,158,910						0	19,158,910
2.	1b		8,266,467	30,135	30,135				0	8,296,602
3.	8		2,625,463	271,902	271,902				0	2,897,365
4.	10		762,661						0	762,661
5.	12	Software		13,061	13,061				0	13,061
6.	45	Computers	78						0	78
7.	47		42,268,303	6,733,204	6,602,308				140,118	48,861,389
8.	50		67,769	141,551	141,551				0	209,320
9.	95	CIP	3,733,732	4,385,783	4,385,783	-3,733,732			0	4,385,783
10.	14.1		1,903,365	115,892	115,892				0	2,019,257
		Totals	78,786,748	11,691,528	11,560,632	-3,733,732			140,118	86,604,426

	1 Class number * See note 1 **200**	Description	10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for property acquired during the year other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 **224**	14 CCA rate % See note 11 **212**	15 Recapture of CCA See note 12 **213**	16 Terminal loss See note 13 **215**	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 **217**	18 UCC at the end of the year (column 9 **minus** column 17) **220**
1.	1						4	0	0	766,356	18,392,554

	1 Class number * See note 1 200	Description	10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for property acquired during the year other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 224	14 CCA rate % See note 11 212	15 Recapture of CCA See note 12 213	16 Terminal loss See note 13 215	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 217	18 UCC at the end of the year (column 9 **minus** column 17) 220
2.	1b			30,135	15,068		6	0	0	498,700	7,797,902
3.	8			271,902	135,951		20	0	0	606,663	2,290,702
4.	10						30	0	0	228,798	533,863
5.	12	Software		13,061			100	0	0	13,061	
6.	45	Computers					45	0	0	35	43
7.	47		9,222	6,593,086	3,296,543		8	0	0	4,172,635	44,688,754
8.	50			141,551	70,776		55	0	0	154,053	55,267
9.	95	CIP		4,385,783	2,192,892		0	0	0		4,385,783
10.	14.1			115,892	57,946		5	0	0	104,964	1,914,293
		Totals	9,222	11,551,410	5,769,176					6,545,265	80,059,161

Enter the total of column 15 on line 107 of Schedule 1.
Enter the total of column 16 on line 404 of Schedule 1.
Enter the total of column 17 on line 403 of Schedule 1.

Note 1. If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101. Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 2. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule.

Note 3. An AIIP is a property (other than ZEV) that you acquired after November 20, 2018 and became available for use before 2028. ZEV is, subject to certain exceptions, a new motor vehicle included in Class 54 or 55 that you acquired after March 18, 2019 and became available for use before 2028. The Government proposes to create Class 56 for zero-emission automotive equipment and vehicles that currently do not benefit from the accelerated rate provided by Classes 54 and 55. Class 56 would apply to eligible zero-emission automotive equipment and vehicles that are acquired after March 1, 2020, and became available for use before 2028. Columns 4, 10, 11, 12 and 13 also apply for additions of class 56 property. See the T2 Corporation Income Tax Guide for more information.

Note 4. Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost (column 9). Items that increase the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the undepreciated capital cost (show amounts that reduce the undepreciated capital cost in brackets) include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the T2 Corporation Income Tax Guide for other examples of adjustments and transfers to include in column 5.
Also include the UCC of each property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property continuously owned by the transferor for at least 364 days before the end of your tax year.

Note 5. Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 6. Include all amounts you have repaid during the year with respect to any legally required repayment, made after the disposition of a corresponding property, of:
- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Also include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) of the Act (also known as "butterfly reorganization") or in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year.

Note 7. For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).
The proceeds of disposition of a ZEV that has been included in Class 54 and that is subject to the $55,000 (plus sales taxes) capital cost limit will be adjusted based on a factor equal to the capital cost limit of $55,000 (plus sales taxes) as a proportion of the actual cost of the vehicle.

Note 8. If the amount in column 5 reduces the undepreciated capital cost (i.e. it is shown in brackets), you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 9. The relevant factors for property of a class in Schedule II, that is AIIP or included in Classes 54 to 56, available for use before 2024 are:
- 2 1/3 for property in Classes 43.1, 54 and 56
- 1 1/2 for property in Class 55
- 1 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, and 15, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 14 for additional information) and
- 0.5 for all other property that is AIIP

Note 10. The UCC adjustment for property acquired during the year other than AIIP and ZEV (formerly known as the half-year rule or 50% rule) does not apply to certain property (including AIIP). For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 11. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 17.

Note 12. If the amount in column 9 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 9 in column 15 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1.

Note 13. If no property is left in the class at the end of the tax year and there is still a positive amount in the column 9, you have a terminal loss. If applicable, enter the positive amount from column 9 in column 16. The terminal loss rules do not apply to:
- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates or
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply

Note 14. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the T2 Corporation Income Tax Guide for more information. For property in class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year. For AIIP listed below, the maximum first year allowance you can claim is determined as follows:
- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraph 1100(1)(y.2)(for single mine properties) and 1100(1)(ya.2)(for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	MILTON HYDRO HOLDINGS INC.		86499 6764 RC0001	1					
2.	Milton Energy and Generation Soluti		86499 6566 RC0001	3					
3.	MILTON HYDRO SERVICES INC.		89573 0414 RC0001	3					
4.	Town of Milton		NR	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Employee Future Benefits	509,917		669,800	509,917	669,800
2						
	Reserves from Part 2 of Schedule 13					
	Totals	509,917		669,800	509,917	669,800

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	MILTON HYDRO HOLDINGS I	200 Chisholm Dr MILTON ON L9T 5E7			97,280		

T2 SCH 14 (99)

Canada

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Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, PRPP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) (see note 3) 600
1	1	519,139	0345983			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule . . . . 519,139 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 422,054 B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") . . . . 97,085 C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer
(EPSP only)

T2 SCH 15 (13)

Canada

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Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year must file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group, including those deemed to be associated under subsection 256(2) of the Income Tax Act.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless association code 5 applies)
2 – CCPC that is a **third corporation** as referred to in subsection 256(2) and has filed Schedule 28, Election not to be Associated Through a Third Corporation
3 – Non-CCPC that is a **third corporation**
4 – Associated non-CCPC
5 – Associated CCPC to which association code 1 does not apply because a **third corporation** has filed Schedule 28

Column 4: Enter the business limit for the year of each corporation in the associated group. Enter "0" if the corporation has association code 2, 3 or 4 in column 3 (except if the corporation is a cooperative or a credit union eligible for the SBD and it has association code 4).

Column 5: Assign a percentage to allocate the business limit to each corporation that has association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . **025** Year Month Day

Enter the calendar year the agreement applies to . . . . . **050** Year 2020

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** ☐ Yes ☒ No

	1 Name of associated corporations **100**	2 Business number of associated corporations **200**	3 Association code **300**	4 Business limit for the year before the allocation $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	1	500,000	100.0000	500,000	
2	MILTON HYDRO HOLDINGS INC.	86499 6764 RC0001	1	500,000			
3	Milton Energy and Generation Solutions Inc.	86499 6566 RC0001	1	500,000			
4	MILTON HYDRO SERVICES INC.	89573 0414 RC0001	1	500,000			
5	Town of Milton	NR	1	500,000			
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (C - $10,000,000). Another factor is the "adjusted aggregate investment income" from lines 744 and 745 of Schedule 7, Aggregate Investment Income and Income Eligible for the Small Business Deduction. Details of these formulas and variable C are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the lesser of: the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	9,246,268		
Capital stock (or members' contributions if incorporated without share capital)	103	17,008,908		
Retained earnings	104	27,903,122		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	65,397,432		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112			
Subtotal (**add** lines 101 to 112)		119,555,730	119,555,730	A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
  a) those lines applied to partnerships in the same manner that they apply to corporations, and
  b) those amounts were computed without reference to amounts owing by the partnership
    (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
    (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)			119,555,730	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121	5,731,083		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123			
Deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal (**add** lines 121 to 124)		5,731,083 ▶	5,731,083	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		113,824,647	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	1,232,297
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	1,232,297

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		113,824,647	C
Deduct: Investment allowance for the year (line 490)		1,232,297	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	112,592,350	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 112,592,350 x (Taxable income earned in Canada **610** 1,184,360 / Taxable income 1,184,360) = **Taxable capital employed in Canada** **690** 112,592,350

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **701** ____

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ____

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ____

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ____

Total deductions (**add** lines 711, 712, and 713) ____ ► ____ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . **790** ____

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . ____ F

Deduct: . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") ____ H

Calculation for purposes of the small business deduction (amount H x 0.225%) . . . . ____ I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount
Customer Deposits		3,667,344 00
Current portion of long-term debt	+	1,686,013 00
Long-term debt	+	60,044,075 00
	+	
	Total	65,397,432 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Part 2 – A loan or advance to another corporation (other than a financial ir

Description	Operator (Note)	Amount	
Prepaids		882,297	00
Intercompany Receivable	+	350,000	00
	+		
	Total	1,232,297	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in calculating income for th

Description	Operator (Note)	Amount	
Sch 13s		669,800	00
Dferred Tax Liabilities	+	8,576,468	00
	+		
	Total	9,246,268	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Schedule 50

Shareholder Information

Corporation's name	Business number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.
- Provide only one number (business number, partnership account number, social insurance number or trust number) per shareholder.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business number or partnership account number (9 digits, 2 letters, and 4 digits. If not registered, enter "**NR**") 200	Social insurance number (9 digits) 300	Trust number (T followed by 8 digits) 350	Percentage common shares 400	Percentage preferred shares 500
1	MILTON HYDRO HOLDINGS INC.	864996764RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, General Rate Income Pool (GRIP) Calculation, or Schedule 54, Low Rate Income Pool (LRIP) Calculation, whichever is applicable.
- File the schedules with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- All legislative references are to the Income Tax Act and the Income Tax Regulations.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		1,500,000		
Total taxable dividends paid in the tax year	100	1,500,000		
Total eligible dividends paid in the tax year			150	
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	17,022,044
Excessive eligible dividend designation (line 150 **minus** line 160)				A
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			180	
Subtotal (amount A **minus** line 180)				B
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount B **multiplied** by 20 %)			190	

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	200			
Total excessive eligible dividend designations in the tax year (amount A of Schedule 54)				C
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			280	
Subtotal (amount C **minus** line 280)				D
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount D **multiplied** by 20 %)			290	

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- Use this schedule if your corporation had a **permanent establishment** (as defined in section 400 of the federal Income Tax Regulations) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- Legislative references are to the federal Income Tax Act and Income Tax Regulations.
- This schedule is a worksheet only and is not required to be filed with your T2 Corporation Income Tax Return.

Part 1 – Ontario basic income tax

Ontario taxable income Note 1	1,184,360	1A
Ontario basic rate of tax for the year	**11.5** %	1B
Ontario basic income tax (amount 1A **multiplied** by amount 1B) Note 2	136,201	1C

Note 1 If your corporation had a permanent establishment only in Ontario, enter the amount from line 360, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Note 2 If your corporation had a permanent establishment in more than one jurisdiction or is claiming an Ontario tax credit in addition to Ontario basic income tax, or Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount 1C on line 270 of Schedule 5, Tax Calculation Supplementary – Corporations. Otherwise, enter it on line 760 of the T2 return.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if your corporation claimed the federal small business deduction under subsection 125(1).

Line 400 of the T2 return			1,188,360	2A
Line 405 of the T2 return			1,184,360	2B
Line 410 of the T2 return		500,000		2C
Line 415 of the T2 return	246,144			2D

Amount 2C 500,000 x Amount 2D 246,144 / 11,250 = 10,939,733 2E

Line 515 of the T2 return				2F
Subtotal (amount 2C **minus** amount 2E **minus** amount 2F)				2G
Amount 2A, 2B or 2G whichever is the least				2H

Ontario domestic factor (ODF): Taxable income for Ontario Note 3 / Taxable income for all provinces Note 4 = 1,184,360.00 / 1,184,360 = 1.00000 2I

Amount 2H **multiplied** by amount 2I		2J	
Ontario taxable income (amount 1A)	1,184,360	2K	
Ontario small business income (amount 2J or 2K, whichever is less)			2L

Ontario small business deduction for the year

Amount 2L ______ x (Number of days in the tax year before January 1, 2020 ______ / Number of days in the tax year 366) x 8 % = ______ 2M

Amount 2L ______ x (Number of days in the tax year after December 31, 2019 366 / Number of days in the tax year 366) x 8.3 % = ______ 2N

Ontario small business deduction for the year (amount 2M **plus** amount 2N) ______ 2O

Enter amount 2O on line 402 of Schedule 5.

Note 3 Enter amount 1A.

Note 4 Includes the territories and the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 3 – Ontario adjusted small business income

Complete this part if your corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (amount 1A or 2H, whichever is the least) 3A

Enter amount 3A at amount 4B in Part 4 of this schedule or at amount 2E in Part 2 of Schedule 502, Ontario Tax Credit for Manufacturing and Processing, whichever applies.

Part 4 – Credit union tax reduction

Complete this part and Schedule 17, Credit Union Deductions, if the corporation was a credit union throughout the tax year.

Amount 3C of Schedule 17 . . . . 4A

Ontario adjusted small business income (amount 3A) 4B

Subtotal (amount 4A **minus** amount 4B, if negative, enter "0") ▶ 4C

Amount 4C ______ x (Number of days in the tax year before January 1, 2020 ______ / Number of days in the tax year 366) x 8 % = ______ 4D

Amount 4C ______ x (Number of days in the tax year after December 31, 2019 366 / Number of days in the tax year 366) x 8.3 % = ______ 4E

Total (amount 4D **plus** amount 4E) ▶ 4F

Ontario domestic factor (amount 2I) 1.00000 4G

Ontario credit union tax reduction (amount 4F **multiplied** by amount 4G) 4H

Enter amount 4H on line 410 of Schedule 5.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	164,593,910
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	82,718,954
Total assets (total of lines 112 to 116)		247,312,864
Total revenue of the corporation for the tax year **	142	144,007,393
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	104,144,769
Total revenue (total of lines 142 to 146)		248,152,162

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

	Line	Amount		Line	Total	
Net income/loss per financial statements *				210	1,058,212	
Add (to the extent reflected in income/loss):						
Provision for current income taxes/cost of current income taxes	220	396,777				
Provision for deferred income taxes (debits)/cost of future income taxes	222					
Equity losses from corporations	224					
Financial statement loss from partnerships and joint ventures	226					
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230					
Other additions (see note below):						
Share of adjusted net income of partnerships and joint ventures **	228					
Total patronage dividends received, not already included in net income/loss	232					
281	282					
283	284					
Subtotal		396,777	▶		396,777	A
Deduct (to the extent reflected in income/loss):						
Provision for recovery of current income taxes/benefit of current income taxes	320					
Provision for deferred income taxes (credits)/benefit of future income taxes	322	109,107				
Equity income from corporations	324					
Financial statement income from partnerships and joint ventures	326					
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330					
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332					
Gain on donation of listed security or ecological gift	340					
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342					
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344					
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346					
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348					
Other deductions (see note below):						
Share of adjusted net loss of partnerships and joint ventures **	328					
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334					
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336					
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338					
381 Tax recovery included in net movements in regulatory	382	424,151				
383 Tax in OCI, not included in line 220 or 322	384	35,366				
385	386					
387	388					
389	390					
Subtotal		568,624	▶		568,624	B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)				490	886,365	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	886,365	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available		▶		C
Net income subject to CMT calculation (if negative, enter "0")		520	886,365	

Amount from line 520 886,365 x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year 366) x 4 % = ______ 1

Amount from line 520 886,365 x (Number of days in the tax year after June 30, 2010 366 / Number of days in the tax year 366) x 2.7 % = 23,932 2

Subtotal (amount 1 **plus** amount 2) 23,932 3

Gross CMT: amount on line 3 above x OAF **	540	23,932	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		23,932	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		136,201	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)			►	620	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			►		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)						M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			136,201	1		
For a corporation that is not a life insurance corporation:						
CMT after foreign tax credit deduction (amount D from Part 3)	23,932	2				
For a life insurance corporation:						
Gross CMT (line 540 from Part 3)		3				
Gross SAT (line 460 from Part 6 of Schedule 512)		4				
The **greater** of amounts 3 and 4		5				
Deduct: line 2 or line 5, whichever applies:			23,932	6		
Subtotal (if negative, enter "0")			112,269	►	112,269	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			136,201			
Deduct:						
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)						
Subtotal (if negative, enter "0")			136,201	►	136,201	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)						P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . ______ Q

Deduct:

CMT loss expired * . . . . **700** ______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ______ ► **720** ______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . **750** ______

CMT loss available (line 720 **plus** line 750) . . . . ______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . ______

Subtotal (if negative, enter "0") ______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . **760** ______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . **770** ______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
MILTON HYDRO DISTRIBUTION INC.	89573 0216 RC0001	2020-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return*.

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	MILTON HYDRO HOLDINGS INC.	86499 6764 RC0001	20,994,515	1,633,864
2	Milton Energy and Generation Solutions Inc.	86499 6566 RC0001	11,717,478	2,510,905
3	MILTON HYDRO SERVICES INC.	89573 0414 RC0001	6,961	0
4	Town of Milton	NR	50,000,000	100,000,000
		Total	450 82,718,954	550 104,144,769

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

T2 SCH 511 Canada

EXHIBIT 4

ATTACHMENT 4-11

INDECO STRATEGIC CONSULTING INC 2023 LRAMVA CLAIM REPORT & LRAMVA MODEL

IndEco

Strategic Solutions for a Changing World™

Milton Hydro Distribution Inc.
2021- 2022 LRAMVA

Milton Hydro Distribution Inc. lost revenue related to Conservation and Demand Management

2021-2022

IndEco

This document was prepared for Milton Hydro Distribution Inc. by IndEco Strategic Consulting Inc.

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IndEco report C1191
2 March 2022

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Introduction

The Lost Revenue Adjustment Mechanism (LRAM) was developed to remove a disincentive electricity local distribution companies (LDCs) may have to promote conservation and demand management (CDM) programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of LDCs. These savings and reductions directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for lost revenue that results from CDM programs the LDC offers to its customers.

Starting in 2011, the Ontario Energy Board (OEB) authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts an LDC included in the LDC's load forecast.[1]

Milton Hydro Distribution Inc. (MHDI) contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of CDM programs to customers in a variety of rate classes for the 2011-2014 period and subsequently with the IESO for the 2015-2020 period.

Lost revenue variances being claimed in the 2023 rate application are summarized in Figure 1.

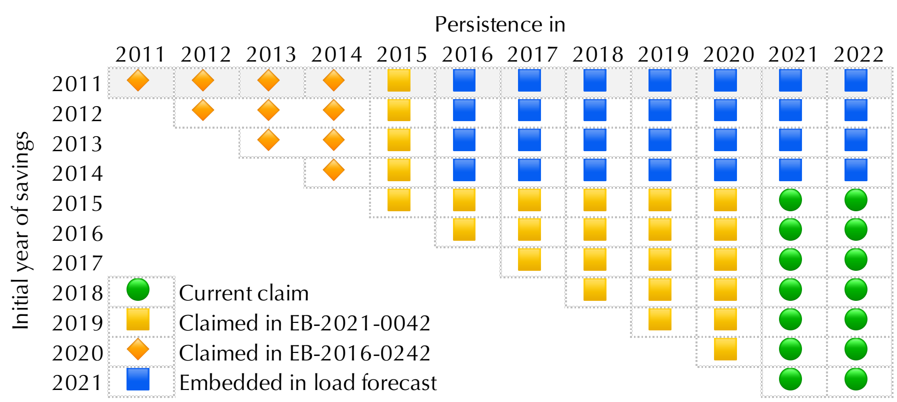

Figure 1 LRAMVA claims

[1] *Guidelines for Electricity Distributor Conservation and Demand Management*. Ontario Energy Board. April 26, 2012 (EB-2012-0003).

MHDI is requesting disposition of the 2022 LRAMVA balance consisting of:

- savings in 2021 of projects approved before April 1, 2019 as part of the Conservation First Framework but completed in 2021
- persistence of these savings from 2021 projects through 2022 and
- persistence in 2021 and 2022 of program savings from projects completed between January 1, 2015 and December 31, 2020 from programs offered through March 31, 2019 under the Conservation First Framework.

Carrying charges on these amounts through December 31, 2022 are also being claimed.

In 2023, new rates, based on a new load forecast, will come into effect. Given that MHDI is no longer offering customers new CDM programs, disposing of the LRAMVA balance that will exist as of December 31, 2022 completes MHDI's LRAMVA claims for the Conservation First Framework (CFF), and is consistent with the recommendation in the most recent version of the OEB's Conservation and Demand Management Guidelines for Electricity Distributors of the OEB:

"Distributors filing an application for 2023 rates should seek disposition of all outstanding LRAMVA balances related to previously established thresholds."[2]

In preparing this claim, the methodology prescribed by the OEB filing requirements has been followed:

"The OEB will rely on the Participation and Cost Reports and detailed project level savings files as supporting documentation when assessing applications for lost revenues in relation to energy and demand savings from programs delivered under the CFF where final verified results from the IESO are not available."[3]

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[2] Ontario Energy Board, 2021. *Conservation and Demand Management Guidelines for Electricity Distributors. EB-2021-0106.*

[3] Ontario Energy Board, 2021. *Filing Requirements for Electricity Distribution Rate Applications*

- 2021 Edition for 2022 Rate Applications. Chapter 2 Cost of Service

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM results – CDM results in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM results, the different time periods of results data and the rate year, and the need to determine carrying charges on the lost revenues.

The most recent input parameters available have been used to calculate the lost revenue values.

The information sources for the LRAMVA analysis are summarized in Table 1.

Table 1 Information sources for LRAMVA analysis

CDM program years	Sources	Information used in this analysis	Used for
2015-2017	2017 final verified results report for MHDI (IESO)	Net first year energy savings by program	Savings
		Net first year demand reductions by program	Savings
		Persistence of results through 2022 by program	Savings
	2015, 2016 and 2017 final verified results by project (IESO)	Net first year energy savings by project	Allocation to rate classes
		Net first year demand reductions by project	Allocation to rate classes
2018 - March 2019	April 2019 Participation & Cost Report for MHDI (IESO)	Unverified first year net savings for 2018, Jan-Apr 2019, and adjustments for 2016 and 2017 by program	Savings
		Unverified persistence in 2020 by program	Savings in 2020
	CDM databases (MHDI)	Reported gross demand savings	Reported gross savings
	2017 final verified results report for MHDI (IESO)	Net-to-Gross and Realization Rates	Calculating net demand savings
		Rate of loss of persistence	Persistence in 2021-2022
2018-2021	CDM databases (MHDI)	Reported gross first year energy savings by project	Gross savings and allocation by program
		Reported gross first year demand savings by project	Gross savings and allocation by program
	2017 final verified results report for MHDI (IESO)	Net-to-Gross and Realization Rates	Calculating net energy and demand savings by program
		Rate of loss of persistence	Persistence into 2021 and 2022 where IESO persistence is not available.
2022	2017 final verified results report for MHDI (IESO)	Rate of loss of persistence	Persistence into 2021 and 2022 where IESO persistence is not available.

CDM RESULTS

For programs offered through 2017, the IESO performed evaluations which examined reported gross energy savings from the programs, and the Realization Rate (RR) and the net-to-gross ratio (NTGR), and then from those calculated net energy savings for each initiative or program. Peak load reductions were also calculated and reported in the same way. For some programs the IESO calculated gross and net energy at the project level.

Provincial results were allocated to individual LDCs based on each LDC's individual performance where possible, or through an allocation process.

The IESO reported energy savings and peak demand reductions, by program in the current year, adjustments to previous years based on updated validation, and contribution to total savings or reductions for the 2015 to 2017 period. The savings and demand reductions for a particular year for most programs persist for several years. The savings and demand reductions for demand response programs do not persist beyond the year in which those savings and demand reductions occur. The IESO provided the persistence into future years of savings and reductions for each program in each year.

Before final evaluation results were available, the IESO published monthly Participation and Cost (P&C) reports that showed both verified and preliminary unverified savings. With the ending of the Conservation First Framework by the Ontario government on April 1, 2019, the IESO stopped producing reports of verified results. Unverified net energy savings for 2018, Q1 2019 and adjustments to program results for earlier years that came in after the 2017 final verified results report are in the April 2019 Participation and Cost reports. Results after the April 2019 Participation and Cost reports are from MHDI databases which record gross values, as reported to the IESO.

The results included projects for streetlighting in the Town of Milton and Halton Region. Energy and demand savings are calculated based on the number and type of fixtures that were retrofitted.

These are the best, most definitive, and defensible estimates of results associated with these programs and incorporate the most appropriate estimates of results from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Allocating results to rate classes

The IESO reports results by program or initiative. These only partially map onto rate classes. The IESO provided net results by project for projects in programs that span multiple rate classes in 2015, 2016 and 2017 and Milton Hydro identified the rate classes for these projects to calculate the allocation across rate classes. For 2018 through 2021, Milton Hydro reported information on projects to the IESO and again the rate classes were identified for individual projects to calculate the allocation. The allocation was calculated according to the billing unit of the relevant rate class. That is, for GS<50 projects, the allocation to GS<50 is the percentage of total kWh for projects in that rate class; for GS>50, their allocation is the percentage of total kW for projects in that rate class.

In most cases, the allocation is straightforward. Only the Retrofit Program, its predecessor the Energy Efficiency Retrofit Initiative (EERI), and the High Performance New Construction program spanned more than one rate class in any given year. For these, allocations were done using the process described in Figure 2.

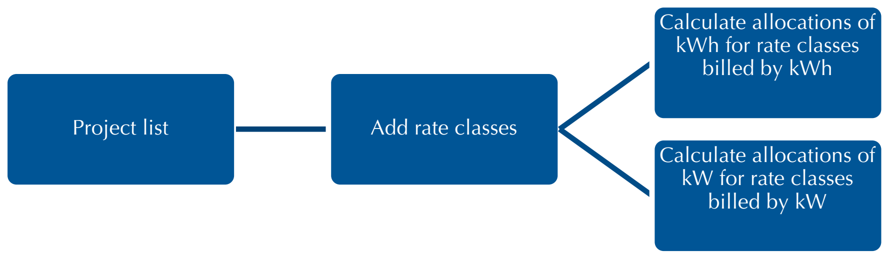

Figure 2 Allocate savings to rate classes

Rate classes were identified for all projects in the program, the percentage of total energy use in each rate class billed by kWh was calculated, and the percentage of total demand reductions in each rate class billed by kW was calculated.

MHDI bills customers in different rate classes using different volumetric units, either kilowatt hours (kWh), or customer peak monthly kilowatts (kW). The rate classes (and billing units) for MHDI are:

- Residential (kWh)
- GS <50 kW (kWh)
- GS 50 to 999 kW (kW)
- GS 1,000 to 4,999 kW (kW)
- Large Use (kW)
- Unmetered Scattered Load (kWh)
- Sentinel Lighting (kW)
- Street Lighting (kW).

The Town of Milton and the Halton Region undertook projects under the Retrofit program to retrofit streetlights to more energy efficient LED bulbs. Savings from these projects persists through 2021 and 2022. These projects were completed after the April 2019 Participation and Cost report. Milton Hydro has tracked the type and wattage of retrofitted fixtures, and details of these are shown on Tab 8 of the LRAMVA workform.

Along with the retrofitting of bulbs, Milton Hydro has been installing meters on the pedestal of streetlights. When meters are installed, the street lamp is transferred from the Street Lighting rate class to the GS<50 kW class. Adding meters is an ongoing process, and does not always occur at the same time that bulbs are retrofitted. Therefore, the allocation of savings between the two rate classes changes over time. As the generic LRAMVA workform the OEB has developed provides for a constant allocation over time, the projects are shown as two separate programs (Retrofit – Metered Streetlights and Retrofit – Unmetered Streetlights). The associated persistent savings over time are calculated based on the combination of when bulbs are retrofitted, and when meters are installed. These calculations are shown on Tab 8 of the LRAMVA workform.

Tables 5-a through 5-g of the OEB LRAMVA work form show the percentage allocation by rate class for 2011 through 2021 results respectively. In each year the rate class allocation percentage totals for each program may not add up to exactly 100% in cases where kWh savings are allocated to rate classes billed by kWh and kW demand reductions are allocated to rate classes billed by kW. The details of the allocation calculation are on Tab 3-a of the work form.

Application of reported results

Through 2017, the IESO reported both energy savings and reductions in demand. Depending on the rate class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. For rate classes where the customer is charged for distribution by energy use (kWh), the IESO reported net energy savings are used to calculate lost revenues related to CDM results. For customer classes where the LDC charges for distribution based on the customer's peak monthly demand (kW), the IESO reported net demand reductions are used to calculate lost revenues related to CDM results. The demand reductions in the IESO reports are multiplied by the number of months a specific program impacts a customer's peak demand. "The IESO indicated that the demand savings from energy efficiency programs shown in the Final CDM Results should generally be multiplied by twelve (12) months to represent the demand savings the distributor has experienced over the entire year…In the case of the Building Commissioning initiative, the demand savings provided in the Final CDM Results should only be multiplied by three (3) as these savings are related to space cooling and do not occur throughout the full year, but only during the summer months, typically."[4]

The OEB has decided that lost revenue cannot be claimed for the kW values reported by the IESO for the Demand Response 3 (DR3) program. "The monthly peak demand of a demand-billed customer

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[4] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2017-0182, May 19, 2017, p. 4.

used for billing purposes may not correspond with the demand response event; even if it did, the lost revenues would only be related to a difference between the customer's peak demand absent the demand response event and the next highest peak demand for the customer in that month … Since the IESO's evaluations cannot confirm the nature of the demand savings relative to the billing period for demand-billed customers, it is not appropriate that distributors be credited with lost revenues from demand response programs, except for those situations where the distributor can explicitly demonstrate revenue impacts."[5]

For 2018 and 2019 and adjustments to earlier years made after the 2017 final results were available, the IESO did not report demand reductions. Demand reductions were estimated based on the reported post-completion gross demand savings by project and the 2017 NTG and RR factors.

Load reductions accounted for in the load forecast

In recent years, LDCs have incorporated projected load losses that will result from CDM programs in their load forecasts, submitted as part of their Cost of Service applications. When determining actual lost revenues, these forecasted reductions in a particular year need to be deducted from load losses attributable to CDM programs in that year to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the results accounted for in the load forecast and the results attributable to the programs.

Anticipated CDM savings in 2016 are provided in the original COS application (EB-2015-0089). During the hearing, this was changed to remove anticipated streetlight savings in 2016, and to remove impacts from 2014 programs which were fully captured in the load forecast regression analysis. These are shown in Table 2-a of the workform.

Persistence

Persistence of 2015 to 2021 results in 2021 and 2022 is shown at the bottom of Tables 5-a to Table 5-g of the workform.

Persistence of programs in 2015 to 2017 is included in the 2017 final verified results report.

The April 2019 Participation and Cost report provided estimated net energy persistence in 2020 for all verified and unverified results.

Where persistence data were not provided, persistence is estimated using the following methods:

- For programs in 2016 to 2019, the annual persistence of the unverified results to 2020 was estimated using linear interpolation between the program year and 2020

[5] Ibid. p. 7.

- For unverified results, persistence in 2021 and 2022 was estimated using the same rate of lost persistence seen in the verified results for that program and that year, if available, or for 2017.

Overall impact of CDM on load, by rate class

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by rate class. Finally, the difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

DISTRIBUTION RATES

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges or pass-throughs for the utility that do not affect the LDC's revenues. An exception for Milton Hydro in 2022, is a rate rider for rate year alignment, since Milton Hydro changed from a May-April rate year to a January to December rate year in 2022. This adjustment only applied from January 2022 to April 2022, or one-third of the year.

For many electricity distribution utilities in Ontario, including MHDI in 2020, distribution rates are set for the period from 1 May to 30 April of the next year. CDM results are reported as first-year savings for programs by calendar year, so average rates for the calendar year need to be calculated. For simplicity, the average 2021 rate is estimated based on the rate being four-twelfths of the 2020 rate (for January through April), and eight-twelfths of the 2021 rate (for May through December). Rates in 2022 were set for the calendar year, so no adjustment was necessary.

CARRYING CHARGES

Because these revenues are lost throughout the year and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB and published on the Board's website. The carrying charges are simple interest, not compounded, and are calculated on the monthly lost revenue balance. Because the IESO final results are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. Thus, 1/12 of the annual results are allocated to each month of the year.

Carrying charges accrue from the latter of the time of the results or a previous LRAMVA claim, until disposition.

Results

Following the methodology described above, lost revenues were calculated for MHDI. The results refer to tables provided in the completed LRAMVA workform that uses the OEB's template.

LOST REVENUES

The lost revenues for each year by rate class for MHDI calculated from final CDM program results are shown in Table 1-b of the OEB LRAMVA work form. The lost revenue for 2021 and 2022 is based on the load impact for each rate class multiplied by the rate for that rate class in that year. The load impact includes only the impact of CDM programs offered through the Conservation First Framework.

Table 1-b of the OEB LRAMVA work form also shows the anticipated lost revenue in 2021 and 2022 due to CDM activities accounted for in MHDI's 2016 Cost of Service applications. The impact on MHDI's revenue is the variance between what is calculated from final CDM program results and estimated CDM activities.

CARRYING CHARGES

The monthly carrying charges by rate class on MHDI's lost revenue variance are shown in Table 6 of the OEB LRAMVA work form. The carrying charges are reported monthly, from the time the lost revenues accrue.

TOTAL LRAMVA CLAIM

The LRAMVA balance on December 31, 2022 for MHDI that includes persistence of results from 2015-2021 CDM programs and projects through to 2021 and 2022 is $530,341. The total carrying charges on this LRAMVA balance accumulated to December 31, 2022 are $3,001. These balances are attributable to individual rate classes according to the following table:

Customer Class	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	$0	$0	$0
GS<50 kW	$249,188	$1,392	$250,579
GS 50 to 999 kW	$103,950	$634	$104,584
GS 1,000 to 4,999 kW	$51,264	$289	$51,553
Large Use	$24,536	$135	$24,670
Unmetered Scattered Load	$0	$0	$0
Sentinel Lighting	$0	$0	$0
Street Lighting	$101,404	$552	$101,956
Total	**$530,341**	**$3,001**	**$533,342**

Ontario Energy Board

Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form

Version 6.0 (2022)

Generic LRAMVA Work Forms

Worksheet Name	Description
1. LRAMVA Summary	**Tables 1-a and 1-b** provide a summary of the LRAMVA balances and carrying charges associated with the LRAMVA disposition. The balances are populated from entries into other tabs throughout this work form.
1-a. Summary of Changes	**Tables A-1 and A-2** include a template for LDCs to summarize changes to the LRAMVA work form.
2. LRAMVA Threshold	**Tables 2-a, 2-b and 2-c** include the LRAMVA thresholds and allocations by rate class.
3. Distribution Rates	**Tables 3-a and 3-b** include the distribution rates that are used to calculate lost revenues.
4. 2011-2014 LRAM	**Tables 4-a, 4-b, 4-c and 4-d** include the template 2011-2014 LRAMVA work forms.
5. 2015-2020 LRAM	**Tables 5-a, 5-b, 5-c and 5-d** include the template 2015-2020 LRAMVA work forms.
6. Carrying Charges	**Table 6-b** includes the variance on carrying charges related to the LRAMVA disposition.
7. Persistence Report	A blank spreadsheet is provided to allow LDCs to populate with CDM savings persistence data provided by the IESO.
8. Streetlighting	A blank spreadsheet is provided to allow LDCs to populate data on streetlighting projects whose savings were not provided by the IESO in the CDM Final Results Report (i.e., streetlighting projects).

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LRAMVA Work Form: Instructions

Version 6.0 (2022)

Tab	Instructions
LRAMVA Checklist/Schematic Tab	The LRAMVA work form was created in a generic manner for use by all LDCs. Distributors should follow the checklist, which is referenced in this tab of the work form and listed below: o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a. o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form. o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved. o Include a copy of initiative-level persistence savings information that was verified by the IESO. Persistence information is available upon request from the IESO. o Apply the IESO verified savings adjustments to the year it relates to. For example, savings adjustments to 2015 programs will be provided to LDCs with the 2016 Final Results Report. The 2015 savings adjustments should be included in the 2015 verified savings portion of the work form. o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable. o Provide documentation or analysis on how rate class allocations were determined by customer class and program each year, inserted in Tab 3-a.
Tab 1. LRAMVA Summary	Distributors are required to report any past approved LRAMVA amounts along with the current LRAMVA amount requested for approval. There are separate tables indicating new lost revenues and carrying charges amounts by year and the totals for rate rider calculations.
Tab 1-a. Summary of Changes	Distributors should list all significant changes and changes in assumptions in the generic work form affecting the LRAMVA.
Tab 2. LRAMVA Threshold	Distributors should use the tables to display the LRAMVA threshold amounts as approved at a rate class level. This should be taken from the LDC's most recently approved cost of service application.
Tab 3. Distribution Rates	Distributors should complete the tables with rate class specific distribution rates and adjustments as applicable.
Tabs 4 and 5 (2011-2020)	Distributors should complete the lost revenue calculation for 2011-2014 program years and 2015-2020 program years, as applicable, by undertaking the following: o Input or manually link the savings, adjustments and program savings persistence data from Tab 7 (Persistence Report) to Tabs 4 and 5. As noted earlier, persistence data is available upon request from the IESO. o Ensure that the IESO verified savings adjustments apply to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. o Confirm the monthly multipliers applied to demand savings. If a different monthly multiplier is used than what was confirmed in the LRAMVA Report, provide rationale in Tab 1-a and highlight the new monthly multiplier that has been used. o Input the rate class allocations by program and year to allocate actual savings to customers. If a different allocation is proposed for adjustments, LDCs must provide the supporting rationale in Tab 1-a and highlight the change. o Provide assumptions about the year(s) in which persistence is captured in the load forecast via the "Notes" section of each table and adjust what is included in the LRAMVA totals, as appropriate.

Tab 6. Carrying Charges	Distributors are requested to calculate carrying charges based on the methodology provided in the work form. This includes updating Table 6 as new prescribed interest rates for deferral and variance accounts become available and entering any collected interest amounts into the "Amounts Cleared" row to calculate outstanding variances on carrying charges.
Tab 7. Persistence Report	Persistence savings report(s) provided by the IESO should be included for the relevant years in the LRAMVA work form. Tab 7 has been created consistently with the IESO's persistence report.
Tab 8. Streetlighting	A tab is provided to ensure LDCs include documentation or data to support projects whose program savings were not provided by the IESO (i.e., streetlighting projects).

Ontario Energy Board

LRAMVA Work Form:
Checklist and Schematic

Version 6.0 (2022)

General Note on the LRAMVA Model

The LRAMVA work form has been created in a generic manner that should allow for use by all LDCs. This LRAMVA work form consolidates information that LDCs are already required to file with the OEB. The model has been created to provide LDCs with a consistent format to display CDM impacts, the forecast savings component and, ultimately, any variance between actual CDM savings and forecast CDM savings. The majority of the information required in the LRAMVA work form will be provided to LDCs from the IESO as part of the Final CDM Results and Participation and Cost Report. Please contact the IESO for any reports that may be required to complete this LRAMVA work form.

The LRAMVA work form is unlocked to enable LDCs to tailor it to their own unique circumstances.

LRAMVA ($) = (Actual Net CDM Savings - Forecast CDM Savings) x Distribution Volumetric Rate + Carrying Charges from LRAMVA balance

Legend — Drop Down List (Blue)

Important Checklist

- o Highlight changes to this work form made by the LDC, if any, and provide rationale for the change in Tab 1-a
- o Include any necessary assumptions the LDC has to make in its LRAMVA work form in the "Notes" section of the work form
- o Provide documentation on the LRAMVA threshold by providing the reference and source material from the LDC's cost of service proceeding where its most recent load forecast was approved
- o Include a copy of initiative-level persistence savings information that was verified by the IESO in Tab 7. Persistence information is available upon request from the IESO
- o Apply the IESO verified savings adjustments to the year it relates to.
- o Provide documentation or data substantiating savings from projects that were not provided in the IESO's verified results reports, inserted in Tab 8 (i.e., streetlighting projects), as applicable

Work Form Calculations	Source of Calculation	Inputs (Tables to Complete)	Source of Data Inputs	Outputs of Data (Auto-Populated)
Actual Incremental CDM Savings by Initiative	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D & O)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+/- IESO Verified Savings Adjustments	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns D-M & Columns O-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
+ Initiative Level Savings Persistence	Tab "4. 2011-2014 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns E-M & Columns P-X)	IESO Verified Persistence Results Reports included in Tab 7 (Columns L to BT).	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AL)
x Allocation % to Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tables 4-a to 4-d / 5-a to 5-f (Columns Y-AJ)	Determined by the LDC	
Actual Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			
- Forecast Lost Revenues (kWh and kW) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"	Tab "2. LRAMVA Threshold" Tables 2-a, 2-b and 2-c		
x Distribution Rate by Rate Class	Tab "3. Distribution Rates"	Table 3	LDC's Approved Tariff Sheets	
LRAMVA ($) by Rate Class	Tabs "4. 2011-2014 LRAM" and "5. 2015-2020 LRAM"			Tables 1-a and 1-b
+ Carrying Charges ($) by Rate Class	Tabs "1. LRAMVA Summary" and "6. Carrying Charges"	Table 6		Table 6-a
Total LRAMVA ($) by Rate Class	Tab "1. LRAMVA Summary"			

Ontario Energy Board

LRAMVA Work Form: Summary Tab

Version 1.0 (2022)

Legend	User Inputs (Green)
	Auto Populated Cells (White)
	Instructions (Grey)

LDC Name Milton Hydro Distribution Inc.

Application Details

Please fill in the requested information: a) the amounts approved in the previous LRAMVA application, b) details on the current application, and c) documentation of changes if applicable.

A. Previous LRAMVA Application

Previous LRAMVA Application (EB#)	EB-2021-0042
Application of Previous LRAMVA Claim	2022 IRM
Period of LRAMVA Claimed in Previous Application	2015-2020
Amount of LRAMVA Claimed in Previous Application	$ 1,150,011

B. Current LRAMVA Application

Current LRAMVA Application (EB#)		EB-2022-0049
Application of Current LRAMVA Claim		2023 COS
Period of New LRAMVA in this Application		2021-2022
Period of Rate Recovery (# years)		2
Actual Lost Revenues ($)	A	**$ 620,426**
Forecast Lost Revenues ($)	B	**$ 90,085**
Carrying Charges ($)	C	**$ 3,001**
LRAMVA ($) for Account 1568	A-B+C	**$ 533,342**

C. Documentation of Changes

Original Amount	
Amount for Final Disposition	

Table 1-a. LRAMVA Totals by Rate Class

Please input the customer rate classes applicable to the LDC and associated billing units (kWh or kW) in Table 1-a below. This will update all tables throughout the workform.

The LRAMVA total by rate class in Table 1-a should be used to inform the determination of rate riders in the Deferral and Variance Account Work Form or IRM Rate Generator Model. Please also ensure that the principal amounts in column E of Table 1-a capture the appropriate years and amounts for the LRAMVA claim. Column F of Table 1-a should include projected carrying charges amounts as determined on a rate class basis from Table 1-b below.

NOTE: If the LDC has more than 14 customer classes in which CDM savings was allocated, LDCs must contact OEB staff to make adjustments to the workform.

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$0	$0	$0
GS<50 kW	kWh	$249,188	$1,392	$250,579
GS 50 to 999 kW	kW	$103,950	$634	$104,584
GS 1,000 to 4,999 kW	kW	$51,264	$289	$51,553
Large Use	kW	$24,536	$135	$24,670
Unmetered Scattered Load	kWh	$0	$0	$0
Sentinel Lighting	kW	$0	$0	$0
Street Lighting	kW	$101,404	$552	$101,956
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
		$0	$0	$0
Total		**$530,341**	**$3,001**	**$533,342**

Table 1-b. Annual LRAMVA Breakdown by Year and Rate Class

In column C of Table 1-b below, please insert a 'check mark' to indicate the years in which LRAMVA has been claimed. If you inserted a check-mark for a particular year, please delete the amounts associated with the actual and forecast lost revenues for all rate classes for that year, up to and including the total. Any LRAMVA from a prior year that has already been claimed cannot be included in the current LRAMVA disposition, with the exception of the case noted below.

If LDCs are seeking to claim true-up amounts that were previously approved by the OEB, please note that the "Amount Cleared" rows are applicable to the LDC and should be filled out. This may relate to claiming the difference in LRAM approved before the May 19, 2016 Peak Demand Consultation, and the lost revenues that would have been incurred after that consultation, as approved by the OEB. If this is the case, reference to the decision must be noted in the rate application. If this is not the case, LDCs are requested to leave those rows blank.

LDCs are expected to include projected carrying charges amounts in row 84 of Table 1-b below. LDCs should also check accuracy of the years included in the LRAMVA balance in row 85.

Description	LRAMVA Previously Claimed	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting							Total
		kWh	kWh	kW	kW	kW	kWh	kW	kW	0	0	0	0	0	0	
2011 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2012 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2013 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2013 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2014 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2014 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2015 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2015 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2016 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2016 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2017 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2017 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2018 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2018 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2019 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

2019 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2020 Actuals		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2020 Forecast		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Amount Cleared																
2021 Actuals		$0.00	$137,527.02	$77,103.38	$29,148.81	$12,752.24	$0.00	$0.00	$50,312.41	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$306,843.86
2021 Forecast		$0.00	($14,355.00)	($25,641.26)	($3,781.82)	($653.11)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($44,431.19)
Amount Cleared																
2022 Actuals		$0.00	$140,754.66	$78,843.70	$29,784.22	$13,107.76	$0.00	$0.00	$51,091.57	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$313,581.90
2022 Forecast		$0.00	($14,738.82)	($26,355.96)	($3,887.28)	($671.32)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	($45,653.39)
Amount Cleared																
Carrying Charges		$0.00	$1,391.59	$633.76	$288.67	$134.82	$0.00	$0.00	$551.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3,000.54
Total LRAMVA Balance		**$0**	**$250,579**	**$104,584**	**$51,553**	**$24,670**	**$0**	**$0**	**$101,956**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$533,341.73**

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form:
Summary of Changes

Version 6.0 (2022)

Legend	
	User Inputs (Green)
	Drop Down List (Blue)
	Instructions (Grey)

Table A-1. Changes to Generic Assumptions in LRAMVA Work Form

Please document any changes in assumptions made to the generic inputs of the LRAMVA work form. This may include, but are not limited to, the use of different monthly multipliers to claim demand savings from energy efficiency programs; use of different rate allocations between current year savings and prior year savings adjustments; inclusion of additional adjustments affecting distribution rates; etc. All changes should be highlighted in the work form as well.

No.	Tab	Cell Reference	Description	Rationale
1	1. LRAMVA Summary	E29:E42	Included values for 2021 and 2022	Claim covers 2021 and 2022
2	1. LRAMVA Summary	Rows 84:89	Added rows for 2021 and 2022	Claim covers 2021 and 2022
3	2. LRAMVA Threshold	Rows 54:55	Added rows for 2021 and 2022	Claim covers 2021 and 2022
4	3. Distribution Rates	P14:P114	Added column for 2022	Claim covers 2021 and 2022
5	3. Distribution Rates	Rows 134:135	Added rows for 2021 and 2022	Claim covers 2021 and 2022
6	3-a. Rate Class Allocations	New tab	Shows details of rate class allocation	Transparency
7	5. 2015-2020 LRAM	Rows 52, 60, 125	Where adjustments made in multiple years, show separately	Transparency
8	5. 2015-2020 LRAM	Y55:AC60, Y123:AC125, Y310:AC311	Distinct allocations for initial results and adjustments	Detailed project information allowed separate allocations to be calculated
9	5. 2015-2020 LRAM	Rows 217:218, 402:403, 587:588, 771:772, 962:963, 1153:1154	Added rows for persistence in 2021 and 2022	Claim covers 2021 and 2022
10	5. 2015-2020 LRAM	B342, B488, B527, B530, B533, B729, B732	Changed unused program name to program name not on default workform	Capture all programs
11	5. 2015-2020 LRAM	Rows 864:871, 1055:1062	Broke out Retrofit program to show non-SL projects, SL projects billed in GS<50, SL rate	Streetlight details on Tab 8. MHDI adding meters to SL, not necessarily at same time as lamp replace
12	5. 2015-2020 LRAM	Rows 1158:1365	New tables for 2021 and 2022	Claim covers 2021 and 2022
13	6. Carrying Charges	Rows C57:C62	Added rates for quarters beyond those reported by OEB using most recent value	Rates for those quarters not available at time of preparing workform
14	6. Carrying Charges	I165:V191	Updated formulae to include 2021 or 2021 and 2022, as appropriate	Claim covers 2021 and 2022
etc.				

Table A-2. Updates to LRAMVA Disposition

Please document any changes related to interrogatories or questions during the application process that affect the LRAMVA amount.

No.	Tab	Cell Reference	Description	Rationale
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
etc.				

Ontario Energy Board

LRAMVA Work Form: Forecast Lost Revenues

Version 6.0 (2022)

Legend

- User Inputs (Green)
- Drop Down List (Blue)
- Auto Populated Cells (White)
- Instructions (Grey)

Table 2-a. LRAMVA Threshold 2016

Please provide the LRAMVA threshold approved in the cost of service (COS) or custom IR (CIR) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting						
		kWh	kWh	kW	kW	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0
kWh	6,363,091	1,633,000	767,647	2,953,909	791,396	217,139									
kW	10,017			7,932	1,669	416									
Summary		1,633,000	767,647	7,932	1,669	416	0	0	0	0	0	0	0	0	0

Years Included in Threshold
Source of Threshold 20XX Settlement Agreement, p. X

Table 2-b. LRAMVA Threshold

Please provide the LRAMVA threshold approved in the cost of service (COS) or custom IR (CIR) application, which is used as the comparator against actual savings in the period of the LRAMVA claim. The LRAMVA threshold should generally be consistent with the annualized savings targets developed from Appendix 2-I. If a manual update is required to reflect a different allocation of forecast savings that was approved by the OEB, please note the changes and provide rationale for the change in Tab 1-a.

	Total	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting						
		kWh	kWh	kW	kW	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0
kWh	0														
kW	0														
Summary		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Years Included in Threshold
Source of Threshold 20XX Settlement Agreement, p. X

Table 2-c. Inputs for LRAMVA Thresholds

Please complete Table 2-c below by selecting the appropriate LRAMVA threshold year in column C. The LRAMVA threshold values in Table 2-c will auto-populate from Tables 2-a and 2-b depending on the year selected. If there was no LRAMVA threshold established for a particular year, please select the "blank" option. The LRAMVA threshold values in Table 2-c will be auto-populated in Tabs 4 and 5 of this work form.

Year	LRAMVA Threshold	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting						
		kWh	kWh	kW	kW	kW	kWh	kW	kW	0.0	0.0	0.0	0.0	0.0	0.0
2011		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2012		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2013		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2014		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020		0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	2016	1,633,000	767,647	7,932	1,669	416	0	0	0	0	0	0	0	0	0
2022	2016	1,633,000	767,647	7,932	1,669	416	0	0	0	0	0	0	0	0	0

Note: LDC to make note of assumptions included above, if any

Ontario Energy Board

LRAMVA Work Form: Distribution Rates

Version 6.0 (2022)

Legend

User Inputs (Green)	
Auto Populated Cells (White)	
Instructions (Grey)	

Tables

Table 3
Table 3-a.

Table 3. Inputs for Distribution Rates and Adjustments by Rate Class

Please complete Table 3 with the rate class specific distribution rates that pertain to the years of the LRAMVA disposition. Any adjustments that affect distribution rates can be incorporated in the calculation by expanding the "plus" button at the left hand bar. Table 3 will convert the distribution rates to a calendar year rate (January to December) based on the number of months entered in row 16 of each rate year starting from January to the start of the LDC's rate year. Please enter 0 in row 16, if the rate year begins on January 1. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas in Table 3-a accordingly.

	Billing Unit	EB-2009-XXXX	EB-2010-XXXX	EB-2011-XXXX	EB-2012-XXXX	EB-2013-XXXX	EB-2014-XXXX	EB-2015-XXXX	EB-2016-XXXX	EB-2017-XXXX	EB-2018-XXXX	EB-2019-XXXX	EB-2020-0039	EB-2021-0042
Rate Year		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Period 1 (# months)												*4*	*4*	*0*
Period 2 (# months)		*12*	*12*	*12*	*12*	*12*	*12*	*12*	*12*	*12*	*12*	*8*	*8*	*12*
Residential												$ -	$ -	$ -
Rate rider for tax sharing														
Rate rider for foregone revenue	kWh													
Other														
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**0**
GS<50 kW												$ 0.0184	$ 0.0188	$ 0.0194
Rate rider for tax sharing														
Rate rider for foregone revenue	kWh													
Other - 1/3 Rate Rider for Rate Year Alignment (Jan-Apr)														-$ 0.0002
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0184	$ 0.0188	$ 0.0192
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.0123**	**$ 0.0187**	0.0192
GS 50 to 999 kW												$ 3.1889	$ 3.2543	$ 3.3568
Rate rider for tax sharing														
Rate rider for foregone revenue	kW													
Other - 1/3 Rate Rider for Rate Year Alignment (Jan-Apr)														-$ 0.0342
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.1889	$ 3.2543	$ 3.3226
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 2.1259**	**$ 3.2325**	3.3226
GS 1,000 to 4,999 kW												$ 2.2357	$ 2.2815	$ 2.3534
Rate rider for tax sharing														
Rate rider for foregone revenue	kW													
Other														-$ 0.0240
Other - 1/3 Rate Rider for Rate Year Alignment (Jan-Apr)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.2357	$ 2.2815	$ 2.3294
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.4905**	**$ 2.2662**	2.3294
Large Use												$ 1.5499	$ 1.5817	$ 1.6315
Rate rider for tax sharing														
Rate rider for foregone revenue	kW													
Other														-$ 0.0166
Other - 1/3 Rate Rider for Rate Year Alignment (Jan-Apr)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.5499	$ 1.5817	$ 1.6149
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1.0333**	**$ 1.5711**	1.6149
Unmetered Scattered Load												$ 0.0176	$ 0.0180	$ 0.0186
Rate rider for tax sharing														
Rate rider for foregone revenue	kWh													
Other														-$ 0.0002
Other - 1/3 Rate Rider for Rate Year Alignment (Jan-Apr)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.0176	$ 0.0180	$ 0.0184

Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 0.0117**	**$ 0.0179**	0.0184
Sentinel Lighting												$ 40.5099	$ 41.3404	$ 42.6426
Rate rider for tax sharing														
Rate rider for foregone revenue	kW													
Other														-$ 0.4341
Other - 1/3 Rate Rider for Rate Year Alignment (Jan-Apr)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 40.5099	$ 41.3404	$ 42.2085
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 27.0066**	**$ 41.0636**	42.2085
Street Lighting												$ 11.1528	$ 11.3814	$ 11.7399
Rate rider for tax sharing														
Rate rider for foregone revenue	kW													
Other - 1/3 Rate Rider for Rate Year Alignment (Jan-Apr)														-$ 0.1195
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.1528	$ 11.3814	$ 11.6204
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 7.4352**	**$ 11.3052**	11.6204
0														
Rate rider for tax sharing														
Rate rider for foregone revenue	0													
Other														
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**		
0														
Rate rider for tax sharing														
Rate rider for foregone revenue	0													
Other														
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**		
0														
Rate rider for tax sharing														
Rate rider for foregone revenue	0													
Other														
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**		
0														
Rate rider for tax sharing														
Rate rider for foregone revenue	0													
Other														
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**		
0														
Rate rider for tax sharing														
Rate rider for foregone revenue	0													
Other														
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**		
0														
Rate rider for tax sharing														
Rate rider for foregone revenue	0													
Other														
Adjusted rate		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Calendar year equivalent			**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**		

Note: LDC to make note of adjustments made to Table 3 to accommodate the LDC's specific circumstances

Table 3-a. Distribution Rates by Rate Class

Table 3-a below autopopulates the average distribution rates from Table 3. Please ensure that the distribution rates relevant to the years of the LRAMVA disposition are used.**Please clear the rates related to the year(s) that are not part of the LRAMVA claim.**

The distribution rates that remain in Table 3-a will be used in Tabs 4 and 5 of the work form to calculate actual and forecast lost revenues. If there are additional adjustments (i.e., rows) added to Table 3, please adjust the formulas from Table 3-a, as well as the distribution rate links in Tabs 4 and 5.

Year	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting						
	kWh	kWh	kW	kW	kW	kWh	kW	kW	0	0	0	0	0	0
2011	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2012	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2013	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2014	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2015	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

2016	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2017	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2018	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2019	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2020														
2021	$0.0000	$0.0187	$3.2325	$2.2662	$1.5711	$0.0179	$41.0636	$11.3052	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
2022	$0.0000	$0.0192	$3.3226	$2.3294	$1.6149	$0.0184	$42.2085	$11.6204	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Note: Years prior to 2021 have already been claimed so distribution rates have been removed for those earlier years

Ontario Energy Board

LRAMVA Work Form: Determination of Rate Class Allocations

Version 5.0 (2021)

Instructions

LDCs must clearly show how it has allocated actual CDM savings to applicable rate classes, including supporting documentation and rationale for its proposal. This should be shown by customer class and program each year.

Applicants are responsible for ensuring that all documents filed with the OEB, including responses to OEB staff questions and other supporting documentation, do not include personal information (as that phrase is defined in the Freedom of Information and Protection of Privacy Act), unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

Application	Program	Year	Rate Class	Energy saving	Demand saving	Report type
137266	Retrofit	2015	GS 50-999 kW	1,198	0.112	Verified
137266	Retrofit	2015	GS 50-999 kW	627	0.199	Verified
137266	Retrofit	2015	GS 50-999 kW	8,439	2.671	Verified
138450	Retrofit	2015	GS 50-999 kW	6,764	2.115	Verified
138450	Retrofit	2015	GS 50-999 kW	12,964	4.054	Verified
138450	Retrofit	2015	GS 50-999 kW	15,772	4.932	Verified
134359	Retrofit	2015	GS<50 kW	750	0.237	Verified
134359	Retrofit	2015	GS<50 kW	2,468	0.806	Verified
134359	Retrofit	2015	GS<50 kW	2,937	0.930	Verified
138800	Retrofit	2015	GS<50 kW	8,880	1.312	Verified
137794	Retrofit	2015	GS 50-999 kW	96,782	23.990	Verified
137794	Retrofit	2015	GS 50-999 kW	851	0.144	Verified
137794	Retrofit	2015	GS 50-999 kW	1,433	0.448	Verified
137794	Retrofit	2015	GS 50-999 kW	169,488	28.692	Verified
139270	Retrofit	2015	GS 50-999 kW	530	0.382	Verified
133146	Retrofit	2015	GS 1,000 to 4,999 kW	6,621	2.180	Verified
137544	Retrofit	2015	GS 50-999 kW	90,373	15.299	Verified
135904	Retrofit	2015	GS 50-999 kW	6,480	2.050	Verified
135904	Retrofit	2015	GS 50-999 kW	6,493	2.055	Verified
140240	Retrofit	2015	GS 50-999 kW	9,744	1.669	Verified
136695	Retrofit	2015	GS<50 kW	31,474	-	Verified
136695	Retrofit	2015	GS<50 kW	-	-	Verified
136695	Retrofit	2015	GS<50 kW	18,357	3.108	Verified
136695	Retrofit	2015	GS<50 kW	34,875	10.906	Verified
136695	Retrofit	2015	GS<50 kW	116,937	19.796	Verified
138133	Retrofit	2015	GS 50-999 kW	18,509	6.298	Verified
138133	Retrofit	2015	GS 50-999 kW	1,597	0.150	Verified
138133	Retrofit	2015	GS 50-999 kW	857	0.271	Verified
138133	Retrofit	2015	GS 50-999 kW	1,182	0.374	Verified
138133	Retrofit	2015	GS 50-999 kW	5,857	1.853	Verified
139903	Retrofit	2015	GS<50 kW	12,852	2.449	Verified
138903	Retrofit	2015	GS<50 kW	1,752	-	Verified
138903	Retrofit	2015	GS<50 kW	28,184	5.642	Verified
138903	Retrofit	2015	GS<50 kW	77	0.024	Verified
138903	Retrofit	2015	GS<50 kW	296	0.094	Verified
138903	Retrofit	2015	GS<50 kW	1,208	0.374	Verified
138920	Retrofit	2015	GS<50 kW	1,898	-	Verified
138920	Retrofit	2015	GS<50 kW	2,804	-	Verified
138920	Retrofit	2015	GS<50 kW	4,468	-	Verified
138920	Retrofit	2015	GS<50 kW	-	-	Verified
138920	Retrofit	2015	GS<50 kW	114,828	15.622	Verified
141013	Retrofit	2015	GS 50-999 kW	6,905	2.143	Verified
135204	Retrofit	2015	GS<50 kW	4,015	0.394	Verified
135204	Retrofit	2015	GS<50 kW	1,161	0.199	Verified
136362	Retrofit	2015	GS<50 kW	533	-	Verified
136362	Retrofit	2015	GS<50 kW	5,575	2.961	Verified
137471	Retrofit	2015	GS<50 kW	1,219	-	Verified
137471	Retrofit	2015	GS<50 kW	6,920	2.849	Verified
134933	Retrofit	2015	GS 50-999 kW	12,499	3.893	Verified
131199	Retrofit	2015	GS<50 kW	3,068	0.959	Verified
142156	Retrofit	2015	GS 50-999 kW	1,878	0.489	Verified
141288	Retrofit	2015	GS 50-999 kW	717	0.224	Verified
141288	Retrofit	2015	GS 50-999 kW	977	0.305	Verified
141288	Retrofit	2015	GS 50-999 kW	1,115	0.349	Verified
141288	Retrofit	2015	GS 50-999 kW	4,282	0.725	Verified
141288	Retrofit	2015	GS 50-999 kW	3,079	0.963	Verified
141288	Retrofit	2015	GS 50-999 kW	113,750	19.256	Verified
142217	Retrofit	2015	GS<50 kW	16,831	4.024	Verified
139172	Retrofit	2015	GS 50-999 kW	73,895	8.371	Verified
143166	Retrofit	2015	GS 50-999 kW	240,493	31.893	Verified
143166	Retrofit	2015	GS 50-999 kW	-	-	Verified
143166	Retrofit	2015	GS 50-999 kW	4,417	-	Verified
143166	Retrofit	2015	GS 50-999 kW	6,405	-	Verified
143166	Retrofit	2015	GS 50-999 kW	12,911	4.086	Verified
143503	Retrofit	2015	GS<50 kW	-	-	Verified
143503	Retrofit	2015	GS<50 kW	7,556	0.744	Verified
143753	Retrofit	2015	GS<50 kW	3,394	1.137	Verified
143753	Retrofit	2015	GS<50 kW	102	0.032	Verified
143753	Retrofit	2015	GS<50 kW	455	0.144	Verified
143753	Retrofit	2015	GS<50 kW	773	0.245	Verified
141540	Retrofit	2015	GS<50 kW	16,940	3.105	Verified
143964	Retrofit	2015	GS 50-999 kW	603	0.764	Verified
144139	Retrofit	2015	GS<50 kW	7,556	0.744	Verified
144115	Retrofit	2015	GS<50 kW	2,316	0.700	Verified
144116	Retrofit	2015	GS<50 kW	8,507	1.440	Verified
144116	Retrofit	2015	GS<50 kW	27,300	4.622	Verified
145233	Retrofit	2015	GS<50 kW	1,079	0.262	Verified
145233	Retrofit	2015	GS<50 kW	177	0.056	Verified
145233	Retrofit	2015	GS<50 kW	302	0.086	Verified
145233	Retrofit	2015	GS<50 kW	998	0.094	Verified
145233	Retrofit	2015	GS<50 kW	694	0.216	Verified
145233	Retrofit	2015	GS<50 kW	937	0.296	Verified
145233	Retrofit	2015	GS<50 kW	1,430	0.452	Verified
145419	Retrofit	2015	GS 50-999 kW	15,356	-	Verified
145252	Retrofit	2015	GS<50 kW	3,116	-	Verified
144443	Retrofit	2015	GS 50-999 kW	9,475	2.963	Verified
145426	Retrofit	2015	GS<50 kW	33,229	7.260	Verified
140265	Retrofit	2015	Large Use	1,327,035	149.781	Verified
141704	Retrofit	2015	GS 50-999 kW	8,158	-	Verified
141704	Retrofit	2015	GS 50-999 kW	23,019	6.123	Verified
145178	Retrofit	2015	GS 50-999 kW	10,801	-	Verified
142393	Retrofit	2015	GS<50 kW	1,024	-	Verified
142394	Retrofit	2015	GS<50 kW	12,575	2.154	Verified
147331	Retrofit	2015	GS<50 kW	40,950	6.932	Verified
146342	Retrofit	2015	GS<50 kW	4,174	1.321	Verified
141326	Retrofit	2015	GS<50 kW	293	0.411	Verified
138897	Retrofit	2015	GS 50-999 kW	836	-	Verified
138897	Retrofit	2015	GS 50-999 kW	1,852	-	Verified
138897	Retrofit	2015	GS 50-999 kW	82,823	28.245	Verified
138897	Retrofit	2015	GS 50-999 kW	1,314	0.416	Verified
144281	Retrofit	2015	GS<50 kW	-	-	Verified
144281	Retrofit	2015	GS<50 kW	15,147	-	Verified
144571	Retrofit	2015	GS 50 to 999 kW	7,218	2.092	Verified
144571	Retrofit	2015	GS 50 to 999 kW	13,804	4.045	Verified
136630	Retrofit	2015	GS<50 kW	9,423	3.718	Verified
129712	Retrofit	2015	GS 50-999 kW	19,210	5.323	Verified
143724	Retrofit	2015	GS 50-999 kW	93,206	14.087	Verified
146632	Retrofit	2015	GS<50 kW	-	-	Verified
146632	Retrofit	2015	GS<50 kW	313	-	Verified
146632	Retrofit	2015	GS<50 kW	8,949	-	Verified
146632	Retrofit	2015	GS<50 kW	396	0.125	Verified
146632	Retrofit	2015	GS<50 kW	1,228	0.389	Verified
146632	Retrofit	2015	GS<50 kW	3,629	0.622	Verified
146632	Retrofit	2015	GS<50 kW	2,615	0.827	Verified
132412	Retrofit	2015	GS 50-999 kW	-	-	Verified
132412	Retrofit	2015	GS 50-999 kW	382	0.121	Verified
132412	Retrofit	2015	GS 50-999 kW	1,933	0.612	Verified
132412	Retrofit	2015	GS 50-999 kW	3,183	1.007	Verified
132412	Retrofit	2015	GS 50-999 kW	2,949	0.933	Verified
132412	Retrofit	2015	GS 50-999 kW	14,173	1.328	Verified
132412	Retrofit	2015	GS 50-999 kW	4,493	1.422	Verified
142083	Retrofit	2015	GS<50 kW	66,876	11.158	Verified
145845	Retrofit	2015	GS<50 kW	4,382	-	Verified
145845	Retrofit	2015	GS<50 kW	16,311	2.755	Verified
149580	Retrofit	2015	GS 50-999 kW	13,302	1.423	Verified
136735	Retrofit	2015	GS 50-999 kW	8,595	-	Verified
136735	Retrofit	2015	GS 50-999 kW	87,837	-	Verified
136737	Retrofit	2015	GS 50-999 kW	6,016	-	Verified
136737	Retrofit	2015	GS 50-999 kW	65,878	-	Verified
148777	Retrofit	2015	GS<50 kW	10,500	3.236	Verified

Year	Type	Program	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Total
2015	Verified	Audit Funding	100.00%	0.00%	0.00%	0.00%	100.00%
2015	Verified	EEM	100.00%	0.00%	0.00%	0.00%	100.00%
2015	Verified	Efficiency: Equipment Replacement Incentive Initiative	10.96%	0.55%	6.28%	53.85%	71.64%
2015	True-up in 2016	Efficiency: Equipment Replacement Incentive Initiative	4.95%	67.35%	0.00%	0.00%	72.30%
2015	True-up in 2017	Efficiency: Equipment Replacement Incentive Initiative	100.00%	0.00%	0.00%	0.00%	100.00%
2015	Verified	Save on Energy Retrofit Program	10.96%	0.55%	6.28%	53.85%	71.64%
2015	True-up in 2016	Save on Energy Retrofit Program	14.53%	72.19%	6.13%	0.00%	92.85%
2015	True-up in 2017	Save on Energy Retrofit Program	0.00%	0.00%	0.00%	100.00%	100.00%
2016	Verified	Save on Energy Audit Funding Program	0.00%	100.00%	0.00%	0.00%	100.00%
2016	True-up in 2017	Save on Energy Energy Manager Program	0.00%	0.00%	0.00%	0.00%	0.00%
2016	Verified	Save on Energy High Performance New Construction Progra	0.00%	0.00%	0.00%	0.00%	0.00%
2016	True-up in 2017	Save on Energy High Performance New Construction Progra	0.00%	100.00%	0.00%	0.00%	100.00%
2016	Verified	Save on Energy Retrofit Program	43.54%	36.60%	21.50%	0.00%	101.64%
2016	True-up in 2017	Save on Energy Retrofit Program	18.10%	82.67%	0.00%	0.59%	101.36%
2017	Verified	Save on Energy Retrofit Program	17.35%	44.16%	27.35%	0.00%	88.87%
2017	Verified	Save on Energy High Performance New Construction Progra	0.00%	100.00%	0.00%	0.00%	100.00%
2017	Verified	Save on Energy Energy Manager Program	0.00%	0.00%	0.00%	0.00%	0.00%
2018	MHDI Data	HPNC	0.00%	100.00%	0.00%	0.00%	100.00%
2018	MHDI Data	PSUI	0.00%	0.00%	100.00%	0.00%	100.00%
2018	MHDI Data	Retrofit	20.18%	31.35%	43.64%	0.54%	95.71%
2019	MHDI Data	Audit Funding	0.00%	0.00%	0.00%	0.00%	0.00%
2019	MHDI Data	Retrofit	13.00%	57.95%	25.84%	0.00%	96.79%
2019	MHDI Data	PSUI	0.00%	0.00%	0.00%	0.00%	0.00%
2020	MHDI Data	Audit Funding	0.00%	0.00%	0.00%	0.00%	0.00%
2020	MHDI Data	Retrofit	100.00%	0.00%	0.00%	0.00%	100.00%
2021	MHDI Data	Retrofit	0.00%	100.00%	0.00%	0.00%	100.00%

124456	Retrofit	2015	GS 50-999 kW	51,143	7.671	Verified
146903	Retrofit	2015	GS<50 kW	11,043	-	Verified
136741	Retrofit	2015	Large Use	656,438	164.187	Verified
134439	Retrofit	2015	GS 1,000 to 4,999 kW	23,133	-	Verified
148927	Retrofit	2015	GS<50 kW	9,329	-	Verified
132556	Retrofit	2015	GS 50-999 kW	48,066	-	Verified
132556	Retrofit	2015	GS 50-999 kW	116,952	-	Verified
132556	Retrofit	2015	GS 50-999 kW	117,485	17.530	Verified
130900	Retrofit	2015	Large Use	501,507	75.231	Verified
132755	Retrofit	2015	Large Use	1,855,382	209.417	Verified
147771	Retrofit	2015	GS 50-999 kW	5,964	1.225	Verified
147771	Retrofit	2015	GS 50-999 kW	5,955	1.705	Verified
145985	Retrofit	2015	GS<50 kW	10,062	-	Verified
145349	Retrofit	2015	GS 50-999 kW	52,761	14.576	Verified
145349	Retrofit	2015	GS 50-999 kW	2,098	-	Verified
145349	Retrofit	2015	GS 50-999 kW	4,095	-	Verified
150891	Retrofit	2015	GS<50 kW	838	-	Verified
150702	Retrofit	2015	GS 50-999 kW	5,564	-	Verified
150702	Retrofit	2015	GS 50-999 kW	2,285	-	Verified
150702	Retrofit	2015	GS 50-999 kW	7,147	-	Verified
150702	Retrofit	2015	GS 50-999 kW	102,692	-	Verified
150702	Retrofit	2015	GS 50-999 kW	107,950	-	Verified
152678	Retrofit	2015	GS<50 kW	-	-	Verified
150024	Retrofit	2015	GS<50 kW	69,015	-	Verified
124878	Retrofit	2015	GS<50 kW	8,503	2.691	Verified
143212	Retrofit	2015	GS 50-999 kW	34,995	-	Verified
143212	Retrofit	2015	GS 50-999 kW	90,736	21.480	Verified
143212	Retrofit	2015	GS 50-999 kW	6,016	-	Verified
143212	Retrofit	2015	GS 50-999 kW	31,370	-	Verified
143589	Retrofit	2015	GS 1,000 to 4,999 kW	-	-	Verified
143589	Retrofit	2015	GS 1,000 to 4,999 kW	-	-	Verified
143589	Retrofit	2015	GS 1,000 to 4,999 kW	38,323	-	Verified
143589	Retrofit	2015	GS 1,000 to 4,999 kW	93,276	20.478	Verified
143589	Retrofit	2015	GS 1,000 to 4,999 kW	422,869	46.422	Verified
143589	Retrofit	2015	GS 1,000 to 4,999 kW	-	-	Verified
143589	Retrofit	2015	GS 1,000 to 4,999 kW	2,393	-	Verified
143589	Retrofit	2015	GS 1,000 to 4,999 kW	4,095	-	Verified
143589	Retrofit	2015	GS 1,000 to 4,999 kW	2,455	0.777	Verified
150021	Retrofit	2015	GS<50 kW	33,144	7.042	Verified
Hydroone-EEM-0155	EEM	2015	GS<50 kW	17,760	5.130	Verified
{ECC8CEDA-D3F8-E41	Audit Funding	2015	GS<50 kW	72,926	15.544	Verified
84918	Save on Energy Retrofit Prograr	2015	GS 50 to 999 kW	49,699	7.887	True-up in 2016
84919	Save on Energy Retrofit Prograr	2015	GS 50 to 999 kW	130,477	19.573	True-up in 2016
84920	Save on Energy Retrofit Prograr	2015	GS<50 kW	29,736	8.441	True-up in 2016
84921	Save on Energy Retrofit Prograr	2015	GS<50 kW	3,274	1.036	True-up in 2016
84922	Save on Energy Retrofit Prograr	2015	GS 1,000 to 4,999 kW	2,584	2.680	True-up in 2016
84923	Save on Energy Retrofit Prograr	2015	GS 50 to 999 kW	5,641	1.181	True-up in 2016
84924	Save on Energy Retrofit Prograr	2015	GS 50 to 999 kW	2,231	2.173	True-up in 2016
84925	Save on Energy Retrofit Prograr	2015	GS 50 to 999 kW	3,516	0.744	True-up in 2016
84926	Save on Energy Retrofit Prograr	2015	GS<50 kW	-	-	True-up in 2016
84927	Save on Energy Retrofit Prograr	2015	GS<50 kW	-	-	True-up in 2016
84928	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	10,239	12.440	Verified
84929	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	10,239	12.440	Verified
84930	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	10,239	12.440	Verified
84931	Save on Energy Retrofit Prograr	2016	GS<50 kW	566,541	97.160	Verified
84932	Save on Energy Retrofit Prograr	2016	GS<50 kW	53,447	15.256	Verified
84933	Save on Energy Retrofit Prograr	2016	GS<50 kW	89,680	25.332	Verified
84934	Save on Energy Retrofit Prograr	2016	Large Use	6,617	-	Verified
84935	Save on Energy Retrofit Prograr	2016	Large Use	187,669	-	Verified
84936	Save on Energy Retrofit Prograr	2016	GS<50 kW	88,999	17.885	Verified
84937	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	11,886	-	Verified
84938	Save on Energy Retrofit Prograr	2016	GS<50 kW	30,521	6.021	Verified
84939	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	376,727	90.006	Verified
84940	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	10,035	-	Verified
84941	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	75,627	17.722	Verified
84942	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	13,388	1.538	Verified
84943	Save on Energy Retrofit Prograr	2016	GS<50 kW	304	0.056	Verified
84944	Save on Energy Retrofit Prograr	2016	GS<50 kW	1,910	-	Verified
84945	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	51,245	6.088	Verified
84946	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	48,046	22.723	Verified
84947	Save on Energy Retrofit Prograr	2016	GS<50 kW	9,586	3.126	Verified
84948	Save on Energy Retrofit Prograr	2016	GS<50 kW	8,439	-	Verified
84949	Save on Energy Retrofit Prograr	2016	GS<50 kW	5,065	1.171	Verified
84950	Save on Energy Retrofit Prograr	2016	GS<50 kW	1,395	-	Verified
84951	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	87,607	17.558	Verified
84952	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	11,039	-	Verified
84953	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	9,935	0.384	Verified
84954	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	69,374	10.383	Verified
84955	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	1,794	-	Verified
84956	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	39,361	8.196	Verified
84957	Save on Energy Retrofit Prograr	2016	GS<50 kW	7,282	0.453	Verified
84958	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	88,722	-	Verified
84959	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	14,376	0.893	Verified
84960	Save on Energy Retrofit Prograr	2016	GS<50 kW	7,946	0.494	Verified
84961	Save on Energy Retrofit Prograr	2016	GS<50 kW	26,740	-	Verified
84962	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	13,569	2.174	Verified
84963	Save on Energy Retrofit Prograr	2016	GS<50 kW	60,061	-	Verified
84964	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	-	-	Verified
84965	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	14,490	1.784	Verified
84966	Save on Energy Retrofit Prograr	2016	GS<50 kW	9,882	-	Verified
84967	Save on Energy Retrofit Prograr	2016	GS<50 kW	6,922	-	Verified
84968	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	526,303	64.796	Verified
84969	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	17,176	1.840	Verified
84970	Save on Energy Retrofit Prograr	2016	GS<50 kW	2,698	0.310	Verified
84971	Save on Energy Retrofit Prograr	2016	GS<50 kW	11,275	0.701	Verified
84972	Save on Energy Retrofit Prograr	2016	GS<50 kW	1,505	-	Verified
84973	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	29,116	3.178	Verified
84974	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	29,344	3.178	Verified
84975	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	23,702	2.732	Verified
84976	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	1,305	-	Verified
84977	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	3,638	-	Verified
84978	Save on Energy Retrofit Prograr	2016	GS<50 kW	23,946	9.311	Verified
84979	Save on Energy Retrofit Prograr	2016	GS<50 kW	711	0.082	Verified
84980	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	70,191	-	Verified
84981	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	38,199	-	Verified
84982	Save on Energy Retrofit Prograr	2016	GS<50 kW	46,650	4.774	Verified
84983	Save on Energy Retrofit Prograr	2016	GS<50 kW	47,507	-	Verified
84984	Save on Energy Retrofit Prograr	2016	GS<50 kW	134,081	-	Verified
84985	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	0.065	Verified
84986	Save on Energy Retrofit Prograr	2016	GS<50 kW	933	0.061	Verified
84987	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	21,305	3.258	Verified
84988	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	39,793	4.649	Verified
84989	Save on Energy Retrofit Prograr	2016	GS<50 kW	70,960	-	Verified
84990	Save on Energy Retrofit Prograr	2016	GS<50 kW	5,691	0.434	Verified
84991	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	3,046	3.458	Verified
84992	Save on Energy Retrofit Prograr	2016	GS<50 kW	1,836	0.121	Verified
84993	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	8,342	0.541	Verified
84994	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	4,365	-	Verified
84995	Save on Energy Retrofit Prograr	2016	GS<50 kW	101,338	17.591	Verified
84996	Save on Energy Retrofit Prograr	2016	GS<50 kW	28,410	3.991	Verified
84997	Save on Energy Retrofit Prograr	2016	GS<50 kW	44,430	5.927	Verified
84998	Save on Energy Retrofit Prograr	2016	GS<50 kW	2,733	2.971	Verified
84999	Save on Energy Retrofit Prograr	2016	GS<50 kW	815	-	Verified
85000	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	1,984	-	Verified
85001	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	10,914	-	Verified
85002	Save on Energy Retrofit Prograr	2016	GS<50 kW	1,945	2.211	Verified
85003	Save on Energy Retrofit Prograr	2016	GS<50 kW	20,455	3.359	Verified
85004	Save on Energy Retrofit Prograr	2016	GS<50 kW	3,686	0.633	Verified
85005	Save on Energy Retrofit Prograr	2016	GS<50 kW	1,472	0.112	Verified
85006	Save on Energy Retrofit Prograr	2016	GS<50 kW	8,731	-	Verified
85007	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	1,857	0.142	Verified
85008	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	-	-	Verified
85009	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85010	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	-	-	Verified
85011	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	-	-	Verified
85012	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85013	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85014	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85015	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85016	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85017	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85018	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85019	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85020	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85021	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85022	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
85023	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	Verified
84047	Efficiency: Equipment Replacer	2015	GS 50 to 999 kW	11,179	-	True-up in 2016
84048	Efficiency: Equipment Replacer	2015	GS<50 kW	307	0.536	True-up in 2016
84049	Efficiency: Equipment Replacer	2015	GS<50 kW	922	0.214	True-up in 2016
84050	Efficiency: Equipment Replacer	2015	GS 50 to 999 kW	12,429	1.548	True-up in 2016
84051	Energy Audit Initiative	2015	#N/A	-	-	True-up in 2016
84076	Save on Energy Audit Funding P	2016	GS 50 to 999 kW	13,143	1.715	Verified
84077	Save on Energy Audit Funding P	2016	GS 50 to 999 kW	n/a	n/a	Verified

84903	Save on Energy High Performan	2016	GS<50 kW	n/a	n/a	Verified
141804	Efficiency: Equipment Replacer	2015	GS<50 kW	5,037	0.525	True-up in 2017
137513	Efficiency: Equipment Replacer	2015	GS<50 kW	55,898	9.447	True-up in 2017
1001-001-EM	Save on Energy Energy Manage	2016	GS 50 to 999 kW	835	-	True-up in 2017
1001-001-EM	Save on Energy Energy Manage	2017	GS 50 to 999 kW	1,305	-	Verified
MiltonHydro10001	Save on Energy High Performan	2016	GS 50 to 999 kW	367,544	75.727	True-up in 2017
10005	Save on Energy High Performan	2017	GS 50 to 999 kW	4,696,753	700.940	Verified
140280	Save on Energy Retrofit Prograr	2015	Large Use	2,391,630	103.772	True-up in 2017
146638	Save on Energy Retrofit Prograr	2016	GS<50 kW	10,869	2.195	True-up in 2017
147522	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	237,777	21.315	True-up in 2017
156057	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	74,061	20.116	True-up in 2017
159012	Save on Energy Retrofit Prograr	2016	GS 50 to 999 kW	18,848	4.938	True-up in 2017
160220	Save on Energy Retrofit Prograr	2016	GS 1,000 to 4,999 kW	89,887	-	True-up in 2017
160987	Save on Energy Retrofit Prograr	2016	GS<50 kW	-	-	True-up in 2017
161690	Save on Energy Retrofit Prograr	2016	Large Use	2,860	0.329	True-up in 2017
162187	Save on Energy Retrofit Prograr	2016	GS<50 kW	2,178	0.732	True-up in 2017
162189	Save on Energy Retrofit Prograr	2016	GS<50 kW	5,869	1.585	True-up in 2017
162271	Save on Energy Retrofit Prograr	2016	GS<50 kW	10,541	2.439	True-up in 2017
162806	Save on Energy Retrofit Prograr	2016	GS<50 kW	3,005	1.158	True-up in 2017
162807	Save on Energy Retrofit Prograr	2016	GS<50 kW	4,248	1.280	True-up in 2017
162840	Save on Energy Retrofit Prograr	2016	GS<50 kW	489	-	True-up in 2017
165386	Save on Energy Retrofit Prograr	2016	GS<50 kW	56,354	-	True-up in 2017
172051	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	94,844	13.336	Verified
172146	Save on Energy Retrofit Prograr	2017	GS<50 kW	416	0.071	Verified
172515	Save on Energy Retrofit Prograr	2017	GS<50 kW	34,882	10.364	Verified
171545	Save on Energy Retrofit Prograr	2017	GS 1,000 to 4,999 kW	167,053	23.854	Verified
173328	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	8,767	1.489	Verified
173984	Save on Energy Retrofit Prograr	2017	GS<50 kW	27,845	10.973	Verified
174095	Save on Energy Retrofit Prograr	2017	GS<50 kW	64,492	25.452	Verified
162964	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	70,643	20.308	Verified
171726	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	118,250	-	Verified
178618	Save on Energy Retrofit Prograr	2017	GS<50 kW	141,350	30.583	Verified
182605	Save on Energy Retrofit Prograr	2017	GS<50 kW	1,464	0.249	Verified
177565	Save on Energy Retrofit Prograr	2017	GS<50 kW	23,145	3.931	Verified
180269	Save on Energy Retrofit Prograr	2017	GS<50 kW	8,313	1.412	Verified
180324	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	702	0.086	Verified
183391	Save on Energy Retrofit Prograr	2017	GS<50 kW	6,046	1.027	Verified
176626	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	263,645	50.716	Verified
177672	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	196,911	31.202	Verified
179899	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	5,871	0.997	Verified
179901	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	13,024	-	Verified
182620	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	4,146	-	Verified
182688	Save on Energy Retrofit Prograr	2017	GS<50 kW	7,361	2.896	Verified
183678	Save on Energy Retrofit Prograr	2017	GS<50 kW	7,893	3.201	Verified
160155	Save on Energy Retrofit Prograr	2017	GS<50 kW	31,835	9.725	Verified
175004	Save on Energy Retrofit Prograr	2017	GS 1,000 to 4,999 kW	24,335	3.886	Verified
175056	Save on Energy Retrofit Prograr	2017	GS 1,000 to 4,999 kW	73,004	11.659	Verified
176657	Save on Energy Retrofit Prograr	2017	GS<50 kW	42,109	9.993	Verified
177457	Save on Energy Retrofit Prograr	2017	GS 1,000 to 4,999 kW	78,958	11.097	Verified
178938	Save on Energy Retrofit Prograr	2017	GS<50 kW	24,914	7.236	Verified
179083	Save on Energy Retrofit Prograr	2017	GS<50 kW	6,218	-	Verified
180608	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	174,523	26.768	Verified
181442	Save on Energy Retrofit Prograr	2017	GS 1,000 to 4,999 kW	12,276	2.542	Verified
183912	Save on Energy Retrofit Prograr	2017	GS<50 kW	7,752	1.316	Verified
172960	Save on Energy Retrofit Prograr	2017	GS<50 kW	9,757	1.657	Verified
174014	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	65,310	10.721	Verified
178093	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	377,385	49.643	Verified
178622	Save on Energy Retrofit Prograr	2017	GS<50 kW	3,090	0.525	Verified
179647	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	82,017	27.173	Verified
185003	Save on Energy Retrofit Prograr	2017	GS<50 kW	2,117	0.360	Verified
185091	Save on Energy Retrofit Prograr	2017	GS<50 kW	4,146	0.671	Verified
185399	Save on Energy Retrofit Prograr	2017	GS<50 kW	56,399	28.488	Verified
187452	Save on Energy Retrofit Prograr	2017	GS<50 kW	548	0.093	Verified
187773	Save on Energy Retrofit Prograr	2017	GS<50 kW	2,201	0.914	Verified
171262	Save on Energy Retrofit Prograr	2017	GS<50 kW	3,992	2.048	Verified
162157	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	46,111	1.586	Verified
185072	Save on Energy Retrofit Prograr	2017	GS 1,000 to 4,999 kW	67,913	13.095	Verified
178745	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	4,614	0.741	Verified
178642	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	8,663	1.405	Verified
178794	Save on Energy Retrofit Prograr	2017	GS 50 to 999 kW	24,703	1.333	Verified
180181	Save on Energy Retrofit Prograr	2017	GS 1,000 to 4,999 kW	737,790	80.955	Verified
185911	Save on Energy Retrofit Prograr	2017	GS<50 kW	53,079	-	Verified
194770	Retrofit	2018	GS<50 kW	17,934	2.250	MHDI Data
194931	Retrofit	2018	GS<50 kW	4,236	0.489	MHDI Data
177005	Retrofit	2018	GS<50 kW	6,935	1.682	MHDI Data
179468	Retrofit	2018	GS<50 kW	8,377	2.025	MHDI Data
181973	Retrofit	2018	GS<50 kW	8,958	2.739	MHDI Data
184028	Retrofit	2018	GS<50 kW	68,203	-	MHDI Data
186314	Retrofit	2018	GS<50 kW	91,819	26.430	MHDI Data
186330	Retrofit	2018	GS<50 kW	78,384	6.084	MHDI Data
187778	Retrofit	2018	GS<50 kW	4,114	0.998	MHDI Data
187843	Retrofit	2018	GS<50 kW	4,703	1.135	MHDI Data
188004	Retrofit	2018	GS<50 kW	14,798	4.011	MHDI Data
188378	Retrofit	2018	GS<50 kW	7,318	-	MHDI Data
188548	Retrofit	2018	GS<50 kW	1,368	0.333	MHDI Data
188751	Retrofit	2018	GS<50 kW	2,827	0.685	MHDI Data
189143	Retrofit	2018	GS<50 kW	20,180	4.558	MHDI Data
189332	Retrofit	2018	GS<50 kW	1,252	0.303	MHDI Data
189333	Retrofit	2018	GS<50 kW	1,380	0.333	MHDI Data
189334	Retrofit	2018	GS<50 kW	1,559	0.381	MHDI Data
189359	Retrofit	2018	GS<50 kW	12,043	-	MHDI Data
189504	Retrofit	2018	GS<50 kW	15,539	-	MHDI Data
189597	Retrofit	2018	GS<50 kW	3,840	-	MHDI Data
190969	Retrofit	2018	GS<50 kW	16,904	4.979	MHDI Data
191513	Retrofit	2018	GS<50 kW	50,908	6.133	MHDI Data
191513	Retrofit	2018	GS<50 kW	55,556	6.818	MHDI Data
191593	Retrofit	2018	GS<50 kW	29,451	6.926	MHDI Data
192219	Retrofit	2018	GS<50 kW	51,235	6.456	MHDI Data
192275	Retrofit	2018	GS<50 kW	8,626	2.064	MHDI Data
192797	Retrofit	2018	GS<50 kW	20,235	4.891	MHDI Data
193690	Retrofit	2018	GS<50 kW	203,158	68.081	MHDI Data
193844	Retrofit	2018	GS<50 kW	70,734	9.371	MHDI Data
194055	Retrofit	2018	GS<50 kW	22,178	6.163	MHDI Data
194824	Retrofit	2018	GS<50 kW	8,784	2.113	MHDI Data
195092	Retrofit	2018	GS<50 kW	7,753	1.956	MHDI Data
195786	Retrofit	2018	GS<50 kW	4,292	-	MHDI Data
196294	Retrofit	2018	GS<50 kW	31,485	5.302	MHDI Data
197407	Retrofit	2018	GS<50 kW	19,650	5.673	MHDI Data
197462	Retrofit	2018	GS<50 kW	15,316	4.402	MHDI Data
197898	Retrofit	2018	GS<50 kW	4,122	1.105	MHDI Data
198321	Retrofit	2018	GS<50 kW	185,944	54.808	MHDI Data
198629	Retrofit	2018	GS<50 kW	50,991	12.325	MHDI Data
198833	Retrofit	2018	GS<50 kW	6,286	-	MHDI Data
198833	Retrofit	2018	GS<50 kW	21,771	4.138	MHDI Data
199124	Retrofit	2018	GS<50 kW	30,635	-	MHDI Data
200064	Retrofit	2018	GS<50 kW	6,389	-	MHDI Data
200600	Retrofit	2018	GS<50 kW	2,062	0.499	MHDI Data
200609	Retrofit	2018	GS<50 kW	74,887	19.221	MHDI Data
201212	Retrofit	2018	GS<50 kW	25,568	6.182	MHDI Data
201800	Retrofit	2018	GS<50 kW	3,752	1.829	MHDI Data
186792	Retrofit	2018	GS 1,000 to 4,999 kW	33,568	4.011	MHDI Data
186793	Retrofit	2018	GS 1,000 to 4,999 kW	33,568	4.304	MHDI Data
193287	Retrofit	2018	GS 1,000 to 4,999 kW	44,758	5.673	MHDI Data
601462	PSUI	2018	GS 1,000 to 4,999 kW	399,242	21.611	MHDI Data
188675	Retrofit	2018	GS 1,000 to 4,999 kW	1,612,135	141.347	MHDI Data
191650	Retrofit	2018	GS 1,000 to 4,999 kW	1,415,774	372.394	MHDI Data
189405	Retrofit	2018	Large Use	51,641	6.554	MHDI Data
10011	HPNC	2018	GS 50 to 999 kW	79,660	16.817	MHDI Data
159225	Retrofit	2018	GS 50 to 999 kW	38,295	-	MHDI Data
165613	Retrofit	2018	GS 50 to 999 kW	62,748	17.803	MHDI Data
167447	Retrofit	2018	GS 50 to 999 kW	23,411	6.544	MHDI Data
181328	Retrofit	2018	GS 50 to 999 kW	4,788	-	MHDI Data
181329	Retrofit	2018	GS 50 to 999 kW	89,741	-	MHDI Data
181332	Retrofit	2018	GS 50 to 999 kW	255,623	-	MHDI Data
186376	Retrofit	2018	GS 50 to 999 kW	192,999	40.301	MHDI Data
187530	Retrofit	2018	GS 50 to 999 kW	50,996	12.452	MHDI Data
187886	Retrofit	2018	GS 50 to 999 kW	139,589	20.884	MHDI Data
189563	Retrofit	2018	GS 50 to 999 kW	69,033	19.926	MHDI Data
190248	Retrofit	2018	GS 50 to 999 kW	9,787	1.360	MHDI Data
190458	Retrofit	2018	GS 50 to 999 kW	218,206	47.148	MHDI Data
190458	Retrofit	2018	GS 50 to 999 kW	133,357	-	MHDI Data
191183	Retrofit	2018	GS 50 to 999 kW	17,501	-	MHDI Data
191464	Retrofit	2018	GS 50 to 999 kW	32,619	-	MHDI Data
192234	Retrofit	2018	GS 50 to 999 kW	47,406	24.533	MHDI Data
192382	Retrofit	2018	GS 50 to 999 kW	290,646	44.801	MHDI Data
192489	Retrofit	2018	GS 50 to 999 kW	19,524	6.163	MHDI Data
193569	Retrofit	2018	GS 50 to 999 kW	10,846	2.622	MHDI Data
194641	Retrofit	2018	GS 50 to 999 kW	37,564	11.073	MHDI Data
194752	Retrofit	2018	GS 50 to 999 kW	9,054	-	MHDI Data
195434	Retrofit	2018	GS 50 to 999 kW	21,772	5.263	MHDI Data
195434	Retrofit	2018	GS 50 to 999 kW	17,887	4.324	MHDI Data
195434	Retrofit	2018	GS 50 to 999 kW	19,911	4.813	MHDI Data
195444	Retrofit	2018	GS 50 to 999 kW	178,188	35.704	MHDI Data
196223	Retrofit	2018	GS 50 to 999 kW	13,598	3.287	MHDI Data

196714	Retrofit	2018	GS 50 to 999 kW	20,993	4.891	MHDI Data
198259	Retrofit	2018	GS 50 to 999 kW	35,959	-	MHDI Data
199040	Retrofit	2018	GS 50 to 999 kW	1,422	0.264	MHDI Data
201934	Retrofit	2018	GS 50 to 999 kW	67,633	11.738	MHDI Data
202428	Retrofit	2018	GS 50 to 999 kW	33,808	9.968	MHDI Data
188289	Retrofit	2018	GS 50 to 999 kW	17,463	7.825	MHDI Data
192818	Retrofit	2018	GS 50 to 999 kW	36,746	8.882	MHDI Data
193821	Retrofit	2018	GS 50 to 999 kW	8,836	1.956	MHDI Data
194478	Retrofit	2018	GS 50 to 999 kW	10,302	3.521	MHDI Data
196000	Retrofit	2018	GS 50 to 999 kW	120,056	19.564	MHDI Data
201213	Retrofit	2018	GS 50 to 999 kW	5,819	1.409	MHDI Data
10000	HPNC	2018	GS 50 to 999 kW	809,966	92.240	MHDI Data
187395	Retrofit	2019	GS<50 kW	7,194	2.044	MHDI Data
187840	Retrofit	2019	GS<50 kW	91,671	-	MHDI Data
187840	Retrofit	2019	GS<50 kW	27,010	3.306	MHDI Data
194952	Retrofit	2019	GS<50 kW	12,820	4.979	MHDI Data
197184	Retrofit	2019	GS<50 kW	14,059	-	MHDI Data
199142	Retrofit	2019	GS<50 kW	28,190	7.982	MHDI Data
200003	Retrofit	2019	GS<50 kW	129,757	25.824	MHDI Data
202559	Retrofit	2019	GS<50 kW	4,232	1.467	MHDI Data
204014	Retrofit	2019	GS<50 kW	6,602	2.445	MHDI Data
204373	Retrofit	2019	GS<50 kW	598	0.665	MHDI Data
204511	Retrofit	2019	GS<50 kW	52,456	-	MHDI Data
205193	Retrofit	2019	GS<50 kW	591	1.565	MHDI Data
205684	Retrofit	2019	GS<50 kW	14,164	3.424	MHDI Data
206553	Retrofit	2019	GS<50 kW	39,011	10.487	MHDI Data
206553	Retrofit	2019	GS<50 kW	2,571	-	MHDI Data
197149	Retrofit	2019	GS 1,000 to 4,999 kW	1,321,115	102.318	MHDI Data
601434	PSUI	2019	GS 1,000 to 4,999 kW	-	-	MHDI Data
20061	Audit	2019	Large Use	-	-	MHDI Data
171329	Retrofit	2019	GS 50 to 999 kW	21,873	5.282	MHDI Data
191502	Retrofit	2019	GS 50 to 999 kW	8,060	-	MHDI Data
191518	Retrofit	2019	GS 50 to 999 kW	8,060	-	MHDI Data
192499	Retrofit	2019	GS 50 to 999 kW	69,202	16.727	MHDI Data
195434	Retrofit	2019	GS 50 to 999 kW	-	-	MHDI Data
196136	Retrofit	2019	GS 50 to 999 kW	107,999	44.214	MHDI Data
196447	Retrofit	2019	GS 50 to 999 kW	7,898	1.937	MHDI Data
199654	Retrofit	2019	GS 50 to 999 kW	102,977	20.874	MHDI Data
204089	Retrofit	2019	GS 50 to 999 kW	17,410	-	MHDI Data
205119	Retrofit	2019	GS 50 to 999 kW	555,001	71.016	MHDI Data
205496	Retrofit	2019	GS 50 to 999 kW	116,992	22.792	MHDI Data
206189	Retrofit	2019	GS 50 to 999 kW	305,134	-	MHDI Data
202956	Retrofit	2019	GS 50 to 999 kW	89,563	11.151	MHDI Data
202956	Retrofit	2019	GS 50 to 999 kW	120,319	33.649	MHDI Data
204483	Retrofit	2019	GS 50 to 999 kW	31,887	1.859	MHDI Data
20060	Audit	2020	GS 1,000 to 4,999 kW	-	-	MHDI Data
156871	Retrofit	2020	GS<50 kW	435,694	31.224	MHDI Data
156872	Retrofit	2020	GS<50 kW	1,109,953	-	MHDI Data
156873	Retrofit	2020	GS<50 kW	642,929	-	MHDI Data
156874	Retrofit	2020	GS<50 kW	981,198	-	MHDI Data
199651	Retrofit	2021	GS 50 to 999 kW	24,215	6.847	MHDI Data
194494	Retrofit	2021	GS 50 to 999 kW	25,985	10.760	MHDI Data

Ontario Energy Board

LRAMVA Work Form:
2011 - 2014 Lost Revenues Work Form

Version 6.0 (2022)

Legend

- User Inputs (Green)
- Auto Populated Cells (White)
- Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2011-2014 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2012 programs that were reported by the IESO in 2013 should be included in the 2012 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 4-a. 2011 Lost Revenues
Table 4-b. 2012 Lost Revenues
Table 4-c. 2013 Lost Revenues
Table 4-d. 2014 Lost Revenues

Table 4-a. 2011 Lost Revenues Work Form

#	Program	Results Status	Net Energy Savings (kWh) 2011	Net Energy Savings Persistence (kWh) 2012	2013	2014	2015	2016	2017	2018	2019	2020	Monthly Multiplier	Net Demand Savings (kW) 2011	Net Peak Demand Savings Persistence (kW) 2012	2013	2014	2015	2016	2017	2018	2019	2020
	Consumer Program																						
1	Appliance Retirement	Verified																					
	Adjustment to 2011 savings	True-up																					
2	Appliance Exchange	Verified																					
	Adjustment to 2011 savings	True-up																					
3	HVAC Incentives	Verified																					
	Adjustment to 2011 savings	True-up																					
4	Conservation Instant Coupon Booklet	Verified																					
	Adjustment to 2011 savings	True-up																					
5	Bi-Annual Retailer Event	Verified																					
	Adjustment to 2011 savings	True-up																					
6	Retailer Co-op	Verified																					
	Adjustment to 2011 savings	True-up																					
7	Residential Demand Response	Verified																					
	Adjustment to 2011 savings	True-up																					
8	Residential Demand Response (IHD)	Verified																					
	Adjustment to 2011 savings	True-up																					
9	Residential New Construction	Verified																					
	Adjustment to 2011 savings	True-up																					
	Business Program																						
10	Retrofit	Verified											12										
	Adjustment to 2011 savings	True-up											12										
11	Direct Install Lighting	Verified											12										
	Adjustment to 2011 savings	True-up											12										
12	Building Commissioning	Verified											3										
	Adjustment to 2011 savings	True-up											3										
13	New Construction	Verified											12										
	Adjustment to 2011 savings	True-up											12										
14	Energy Audit	Verified											12										
	Adjustment to 2011 savings	True-up											12										
15	Small Commercial Demand Response	Verified																					
	Adjustment to 2011 savings	True-up																					
16	Small Commercial Demand Response (IHD)	Verified																					
	Adjustment to 2011 savings	True-up																					
17	Demand Response 3	Verified																					
	Adjustment to 2011 savings	True-up																					
	Industrial Program																						
18	Process & System Upgrades	Verified											12										
	Adjustment to 2011 savings	True-up											12										
19	Monitoring & Targeting	Verified											12										

#	Program	Results Status	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Consumer Program		kWh	kWh	kW	kW	kW	kWh	kW	kW	
1	Appliance Retirement	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program										
10	Retrofit	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program										
18	Process & System Upgrades	Verified									0%
	Adjustment to 2011 savings	True-up	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified									0%

	Adjustment to 2011 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified		12										0%
	Adjustment to 2011 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified		12										0%
	Adjustment to 2011 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified												0%
	Adjustment to 2011 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program													
23	Home Assistance Program	Verified												0%
	Adjustment to 2011 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program													
24	Home Assistance Program	Verified												0%
	Adjustment to 2011 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified		0										0%
	Adjustment to 2011 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011													
26	Electricity Retrofit Incentive Program	Verified		12										0%
	Adjustment to 2011 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified		12										0%
	Adjustment to 2011 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified		0										0%
	Adjustment to 2011 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified		0										0%
	Adjustment to 2011 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified		0										0%
	Adjustment to 2011 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other													
31	Program Enabled Savings	Verified		0										0%
	Adjustment to 2011 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified		0										0%
	Adjustment to 2011 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified		12										0%
	Adjustment to 2011 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2011		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Forecast CDM Savings in 2011					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2011					$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2011 from 2011 programs					**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2011					**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2011													**$0.00**
	2011 Savings Persisting in 2012					0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2013					0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2014					0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2015					0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2016					0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2017					0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2018					0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2019					0	0	0	0	0	0	0	0	
	2011 Savings Persisting in 2020					0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 4-b. 2012 Lost Revenues Work Form

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	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA								
			2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Consumer Program																							kWh	kWh	kW	kW	kW	kWh	kW	kW	
1	Appliance Retirement	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program																															
10	Retrofit	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified											3																			0%
	Adjustment to 2012 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

13	New Construction	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																															
18	Process & System Upgrades	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																															
23	Home Assistance Program	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program																															
24	Home Assistance Program	Verified																														0%
	Adjustment to 2012 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified											0																			0%
	Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																															
26	Electricity Retrofit Incentive Program	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified											0																			0%
	Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified											0																			0%
	Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified											0																			0%
	Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																															
31	Program Enabled Savings	Verified											0																			0%
	Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified											0																			0%
	Adjustment to 2012 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified											12																			0%
	Adjustment to 2012 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2012		0											0										0	0	0	0	0	0	0	0	
	Forecast CDM Savings in 2012																							0	0	0	0	0	0	0	0	
	Distribution Rate in 2012																							$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2012 from 2011 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2012 from 2012 programs																							$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2012																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2012																							**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2012																															**$0.00**
	2012 Savings Persisting in 2013																							0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2014																							0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2015																							0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2016																							0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2017																							0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2018																							0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2019																							0	0	0	0	0	0	0	0	
	2012 Savings Persisting in 2020																							0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 4-c. 2013 Lost Revenues Work Form

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#	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA								
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Consumer Program																							kWh	kWh	kW	kW	kW	kWh	kW	kW	
1	Appliance Retirement	Verified																														0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified																														0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified																														0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified																														0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified																														0%
	Adjustment to 2013 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

6	Retailer Co-op	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program													
10	Retrofit	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified		3										0%
	Adjustment to 2013 savings	True-up		3		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program													
18	Process & System Upgrades	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program													
23	Home Assistance Program	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program													
24	Home Assistance Program	Verified												0%
	Adjustment to 2013 savings	True-up				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified		0										0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011													
26	Electricity Retrofit Incentive Program	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified		0										0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified		0										0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified		0										0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other													
31	Program Enabled Savings	Verified		0										0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified		0										0%
	Adjustment to 2013 savings	True-up		0		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified		12										0%
	Adjustment to 2013 savings	True-up		12		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2013		0		0	0	0	0	0	0	0	0	0	
	Forecast CDM Savings in 2013					0	0	0	0	0	0	0	0	
	Distribution Rate in 2013					$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2013 from 2011 programs					$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2013 from 2012 programs					$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2013 from 2013 programs					$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2013					**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2013					**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2013													**$0.00**
	2013 Savings Persisting in 2014					0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2015					0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2016					0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2017					0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2018					0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2019					0	0	0	0	0	0	0	0	
	2013 Savings Persisting in 2020					0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 4-d. 2014 Lost Revenues Work Form

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	Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA								
			2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Consumer Program																							kWh	kWh	kW	kW	kW	kWh	kW	kW	
1	Appliance Retirement	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Appliance Exchange	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	HVAC Incentives	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	Conservation Instant Coupon Booklet	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Bi-Annual Retailer Event	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
6	Retailer Co-op	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Residential Demand Response	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Residential Demand Response (IHD)	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
9	Residential New Construction	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Business Program																															
10	Retrofit	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	Direct Install Lighting	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
12	Building Commissioning	Verified											3																			0%
	Adjustment to 2014 savings	True-up											3											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	New Construction	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
14	Energy Audit	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
15	Small Commercial Demand Response	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
16	Small Commercial Demand Response (IHD)	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
17	Demand Response 3	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program																															
18	Process & System Upgrades	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
19	Monitoring & Targeting	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
20	Energy Manager	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
21	Retrofit	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Demand Response 3	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Home Assistance Program																															
23	Home Assistance Program	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Aboriginal Program																															
24	Home Assistance Program	Verified																														0%
	Adjustment to 2014 savings	True-up																						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
25	Direct Install Lighting	Verified											0																			0%
	Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pre-2011 Programs completed in 2011																															
26	Electricity Retrofit Incentive Program	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
27	High Performance New Construction	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Toronto Comprehensive	Verified											0																			0%
	Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
29	Multifamily Energy Efficiency Rebates	Verified											0																			0%
	Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30	LDC Custom Programs	Verified											0																			0%
	Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other																															
31	Program Enabled Savings	Verified											0																			0%
	Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Time of Use Savings	Verified											0																			0%
	Adjustment to 2014 savings	True-up											0											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
33	LDC Pilots	Verified											12																			0%
	Adjustment to 2014 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

Actual CDM Savings in 2014	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2014			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Distribution Rate in 2014			$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2014 from 2011 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2014 from 2012 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2014 from 2013 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2014 from 2014 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2014			**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2014			**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2014											**$0.00**
2014 Savings Persisting in 2015			0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2016			0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2017			0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2018			0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2019			0	0	0	0	0	0	0	0	
2014 Savings Persisting in 2020			0	0	0	0	0	0	0	0	

Note: LDC to make note of key assumptions included above

Ontario Energy Board

LRAMVA Work Form:
2015 - 2020 Lost Revenues Work Form

Version 6.0 (2022)

Legend

User Inputs (Green)
Auto Populated Cells (White)
Instructions (Grey)

Instructions

1. LDCs can apply for disposition of LRAMVA amounts at any time, but at a minimum, must do so as part of a cost of service (COS) application. The following LRAMVA work forms apply to LDCs that need to recover lost revenues from the 2015-2020 period. Please input or manually link the savings, adjustments and program savings persistence data in these tables from the LDC's Persistence Reports provided by the IESO (in Tab 7). As noted earlier, persistence data is available upon request from the IESO. Please also be advised that the same rate classes (of up to 14) are carried over from the Summary Tab 1.

2. Please ensure that the IESO verified savings adjustments apply back to the program year it relates to. For example, savings adjustments related to 2016 programs that were reported by the IESO in 2017 should be included in the 2016 program savings table. In order for persisting savings to be claimed in future years, past year's initiative level savings results need to be filled out in the tables below. If the IESO adjustments were made available to the LDC after the LRAMVA was approved, the persistence of those savings adjustments in the future can be claimed as approved LRAMVA amounts are considered to be final.

3. The work forms below include the monthly multipliers for most programs in order to claim demand savings from energy efficiency programs, consistent with the monthly multipliers indicated in the OEB's updated LRAM policy related to peak demand savings in EB-2016-0182. Demand Response (DR3) savings should generally not be included with the LRAMVA calculation, unless suported by empirical evidence. LDCs are requested to confirm the monthly multipliers for all programs each year as placeholder values are provided. If a different monthly multiplier is used, please include rationale in Tab 1-a and highlight the new multiplier that has been used.

4. LDC are requested to input the applicable rate class allocation percentages to allocate actual savings to the rate classes. The generic template currently includes the same allocation percentage for program savings and its savings adjustments. If a different allocation is proposed for savings adjustments, LDCs must provide supporting rationale in Tab 1-a and highlight the change.

5. The persistence of future savings is expected to be included in the distributor's load forecast after re-basing. LDCs are requested to delete the applicable savings persistence rows (auto-calculated after the LRAMVA totals for the year) if future year's persistence of savings is already captured in the updated load forecast. Please also provide assumptions about the years in which persistence is captured in the load forecast calculation in the "Notes" section below each table.

Tables

Table 5-a. 2015 Lost Revenues
Table 5-b. 2016 Lost Revenues
Table 5-c. 2017 Lost Revenues
Table 5-d. 2018 Lost Revenues
Table 5-e. 2019 Lost Revenues
Table 5-f. 2020 Lost Revenues

Table 5-a. 2015 Lost Revenues Work Form

#	Program	Results Status	Net Energy Savings (kWh) 2015	Net Energy Savings Persistence (kWh) 2016	2017	2018	2019	2020	2021	2022	2023	2024	Monthly Multiplier	Net Demand Savings (kW) 2015	Net Peak Demand Savings Persistence (kW) 2016	2017	2018	2019	2020	2021	2022	2023	2024
	Legacy Framework																						
	Residential Program																						
1	Coupon Initiative	Verified	302,531	299,778	299,778	299,778	299,778	299,778	299,778	299,712	299,712	299,712		20	19	19	19	19	19	19	19	19	19
	Adjustment to 2015 savings	True-up	50,526	49,799	49,799	49,799	49,799	49,799	49,799	49,779	49,779	49,779		3	3	3	3	3	3	3	3	3	3
2	Bi-Annual Retailer Event Initiative	Verified	558,905	548,972	548,972	548,972	548,972	548,972	548,972	548,685	548,685	548,685		38	37	37	37	37	37	37	37	37	37
	Adjustment to 2015 savings	True-up	5,781	5,713	5,713	5,713	5,713	5,713	5,713	5,699	5,699	5,699		0	0	0	0	0	0	0	0	0	0
3	Appliance Retirement Initiative	Verified	7,634	7,634	7,634	7,634	4,070	0	0	0	0	0		1	1	1	1	1	0	0	0	0	0
	Adjustment to 2015 savings	True-up																					
4	HVAC Incentives Initiative	Verified	352,692	352,692	352,692	352,692	352,692	352,692	352,692	352,692	352,692	352,692		193	193	193	193	193	193	193	193	193	193
	Adjustment to 2015 savings	True-up	14,876	14,876	14,876	14,876	14,876	14,876	14,876	14,876	14,876	14,876		8	8	8	8	8	8	8	8	8	8
5	Residential New Construction and Major	Verified	465,845	465,845	465,845	465,845	465,845	465,845	465,845	465,845	465,845	465,845		115	115	115	115	115	115	115	115	115	115
	Adjustment to 2015 savings in 2016	True-up	152,607	152,607	152,607	152,607	152,607	152,607	152,607	152,607	152,607	152,607		8	8	8	8	8	8	8	8	8	8
	Adjustment to 2015 savings in 2017	True-up	65,406	65,406	65,406	65,406	65,406	65,406	65,406	65,406	65,406	65,406		4	4	4	4	4	4	4	4	4	4
	Commercial & Institutional Program																						
6	Energy Audit Initiative	Verified	72,926	72,926	72,926	72,926	0	0	0	0	0	0	12	16	16	16	16	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											12										
7	Efficiency: Equipment Replacement Incentive Initiative	Verified	8,044,425	8,044,425	8,024,936	8,024,936	8,024,936	8,005,726	7,587,817	7,587,817	7,519,491	6,151,714	12	1,112	1,112	1,106	1,106	1,106	1,100	1,044	1,044	1,027	845
	Adjustment to 2015 savings	True-up	24,837	24,837	24,837	24,837	24,837	24,837	24,739	24,739	24,739	24,323	12	2	2	2	2	2	2	2	2	2	2
	Adjustment to 2015 savings in 2017	True-up	70,294	70,294	89,783	90,195	90,195	90,195	508,202	508,202	522,909	403,534	12	12	12	19	19	19	19	75	75	75	58
8	Direct Install Lighting and Water Heating Initiative	Verified	207,659	196,489	190,651	190,651	190,651	190,651	190,651	190,651	190,651	190,651	12	45	42	41	41	41	41	41	41	41	41
	Adjustment to 2015 savings	True-up	-20,510	-9,340	-3,503	-462	-462	-462	-462	-462	-462	-462	12	-5	-2	-1	0	0	0	0	0	0	0
	Industrial Program																						
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative	Verified	17,760	17,760	17,760	17,760	17,760	17,760	17,760	17,760	17,760	17,760	12	5	5	5	5	5	5	5	5	5	5
	Adjustment to 2015 savings	True-up											12										
	Low Income Program																						
14	Low Income Initiative	Verified	9,138	8,345	8,212	8,078	8,078	8,078	8,078	8,078	6,833	6,833	12	1	1	1	1	1	1	1	1	1	1
	Adjustment to 2015 savings	True-up	1,231	1,130	1,119	1,108	1,108	1,108	1,108	1,108	942	942	12	0	0	0	0	0	0	0	0	0	0
	Other																						
20	Social Benchmarking Pliot	Verified	262,063	0	0	0	0	0	0	0	0	0	12	74	0	0	0	0	0	0	0	0	0
	Adjustment to 2015 savings	True-up											12										
	Conservation First Framework																						
	Non-Residential Province-Wide Programs																						
26	Save on Energy Retrofit Program	Verified											12										
	Adjustment to 2015 savings	True-up	227,158	227,158	227,158	227,158	227,158	227,158	219,585	219,585	216,311	192,395	12	44	44	44	44	44	44	42	42	41	36
	Adjustment to 2015 savings in 2017	True-up	2,391,630	2,391,630	2,391,630	2,391,630	2,391,630	2,391,630	2,399,203	2,399,203	2,399,203	2,396,967	12	104	104	104	104	104	104	105	105	105	105
	Actual CDM Savings in 2015		**13,285,414**											**1,800**									
	Forecast CDM Savings in 2015																						

#	Program	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Legacy Framework	kWh	kWh	kW	kW	kW	kWh	kW	kW	
	Residential Program									
1	Coupon Initiative	100.00%								100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2	Bi-Annual Retailer Event Initiative	100.00%								100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
3	Appliance Retirement Initiative	100.00%								100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
4	HVAC Incentives Initiative	100.00%								100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
5	Residential New Construction and Major	100.00%								100%
	Adjustment to 2015 savings in 2016	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Adjustment to 2015 savings in 2017	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Commercial & Institutional Program									
6	Energy Audit Initiative		100.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
7	Efficiency: Equipment Replacement Incentive Initiative		11%	1%	6.28%	54%				72%
	Adjustment to 2015 savings	0.00%	4.95%	67.35%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Adjustment to 2015 savings in 2017	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
8	Direct Install Lighting and Water Heating Initiative		100%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Industrial Program									
13	Process and Systems Upgrades Initiatives - Energy Manager Initiative		100.00%	0.00%	0.00%	0.00%				100%
	Adjustment to 2015 savings	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Low Income Program									
14	Low Income Initiative	100%								100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Other									
20	Social Benchmarking Pliot	100.00%								100%
	Adjustment to 2015 savings	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Conservation First Framework									
	Non-Residential Province-Wide Programs									
26	Save on Energy Retrofit Program		11%	1%	6.28%	54%				72%
	Adjustment to 2015 savings	0.00%	14.53%	72.19%	6.13%	0.00%	0.00%	0.00%	0.00%	
	Adjustment to 2015 savings in 2017	0.00%	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%		
	Actual CDM Savings in 2015	**2,249,235**	**1,264,315**	**471**	**871**	**8,433**	**0**	**0**	**0**	
	Forecast CDM Savings in 2015	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Distribution Rate in 2015	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
	Lost Revenue in 2015 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2015 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2015 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2015 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Lost Revenue in 2015 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total Lost Revenues in 2015	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	Forecast Lost Revenues in 2015	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
	LRAMVA in 2015									**$0.00**
	2015 Savings Persisting in 2016	1,972,797	1,264,315	471	871	8,433	0	0	0	
	2015 Savings Persisting in 2017	1,972,653	1,281,666	471	866	8,394	0	0	0	
	2015 Savings Persisting in 2018	1,972,508	1,285,119	471	866	8,394	0	0	0	

	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
2015 Savings Persisting in 2019	1,968,944	1,212,193	471	866	8,394	0	0	0
2015 Savings Persisting in 2020	1,964,874	1,210,087	470	862	8,356	0	0	0
2015 Savings Persisting in 2021	1,964,874	1,581,171	449	818	8,006	0	0	0
2015 Savings Persisting in 2022	1,964,487	1,581,171	449	818	8,006	0	0	0

Note: LDC to make note of key assumptions included above

Table 5-b. 2016 Lost Revenues Work Form Return to top

	Program	Results Status	Net Energy Savings (kWh) 2016	Net Energy Savings Persistence (kWh) 2017	2018	2019	2020	2021	2022	2023	2024	2025	Monthly Multiplier	Net Demand Savings (kW) 2016	Net Peak Demand Savings Persistence (kW) 2017	2018	2019	2020	2021	2022	2023	2024	2025	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Conservation First Framework																															
	Residential Province-Wide Programs																															
21	Save on Energy Coupon Program	Verified	2,180,560	2,180,560	2,180,560	2,180,560	2,180,560	2,180,560	2,180,560	2,180,234	2,180,234	2,170,774		142	142	142	142	142	142	142	142	142	141	100.00%								100%
	Adjustment to 2016 savings	True-up	245,089	245,089	245,089	245,089	245,089	245,089	245,089	245,066	245,066	245,432		16	16	16	16	16	16	16	16	16	16	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified	496,561	496,561	496,561	496,561	496,561	496,561	496,561	496,561	496,561	496,561		151	151	151	151	151	151	151	151	151	151	100.00%								100%
	Adjustment to 2016 savings	True-up	4,847	4,847	4,847	4,847	4,847	4,847	4,847	4,847	4,847	4,847		1	1	1	1	1	1	1	1	1	1	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	Verified	280,940	280,940	280,940	280,940	280,940	280,940	280,940	280,940	280,940	280,940		60	60	60	60	60	60	60	60	60	60	100.00%								100%
	Adjustment to 2016 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																															
25	Save on Energy Audit Funding Program	Verified	13,143	13,143	13,143	13,143	13,143	13,143	13,143	13,143	13,143	13,143	12	2	2	2	2	2	2	2	2	2	2		0.00%	100.00%	0.00%	0.00%				100%
	Adjustment to 2016 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified	3,636,533	3,529,335	3,529,335	3,529,335	3,529,335	3,505,706	3,505,706	3,505,706	3,419,127	3,419,127	12	544	524	524	524	524	521	521	521	504	504		43.54%	36.60%	21.50%	0.00%				102%
	Adjustment to 2016 savings	True-up	628,739	735,937	736,348	736,348	736,348	736,348	736,348	736,348	736,348	736,348	12	77	96	96	96	96	96	96	96	96	96	0.00%	18.10%	82.67%	0.00%	0.59%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified											12																			0%
	Adjustment to 2016 savings	True-up	367,544	367,544	367,544	367,544	367,544	367,544	367,544	367,544	367,544	367,544	12	76	76	76	76	76	76	76	76	76	76	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified											12												0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2016 savings	True-up	835	835	835	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs																															
36	Home Depot Home Appliance Market Uplift Conservation Fund Pilot Program	Verified	550	550	550	550	550	550	550	550	550	550	12	0	0	0	0	0	0	0	0	0	0	100.00%								100%
	Adjustment to 2016 savings	True-up											12											100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Actual CDM Savings in 2016		**7,855,341**											**1,069**										**3,208,547**	**1,696,974**	**4,089**	**1,404**	**5**	**0**	**0**	**0**	
	Forecast CDM Savings in 2016																							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Distribution Rate in 2016	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2016 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2016 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2016	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2016	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2016									**$0.00**
2016 Savings Persisting in 2017	3,208,547	1,669,703	4,190	1,352	7	0	0	0	
2016 Savings Persisting in 2018	3,208,547	1,669,777	4,190	1,352	7	0	0	0	
2016 Savings Persisting in 2019	3,208,547	1,669,777	4,190	1,352	7	0	0	0	
2016 Savings Persisting in 2020	3,208,547	1,669,777	4,190	1,352	7	0	0	0	
2016 Savings Persisting in 2021	3,208,547	1,659,490	4,177	1,344	7	0	0	0	
2016 Savings Persisting in 2022	3,208,547	1,659,490	4,177	1,344	7	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-c. 2017 Lost Revenues Work Form Return to top

	Program	Results Status	Net Energy Savings (kWh) 2017	Net Energy Savings Persistence (kWh) 2018	2019	2020	2021	2022	2023	2024	2025	2026	Monthly Multiplier	Net Demand Savings (kW) 2017	Net Peak Demand Savings Persistence (kW) 2018	2019	2020	2021	2022	2023	2024	2025	2026	Rate Allocations for LRAMVA: Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
	Conservation First Framework																															
	Residential Province-Wide Programs																															
21	Save on Energy Coupon Program	Verified	3,651,714	2,931,802	2,931,802	2,931,802	2,931,802	2,931,802	2,931,802	2,931,776	2,931,776	2,925,607		252	204	204	204	204	204	204	204	204	203	100.00%								100%
	Adjustment to 2017 savings in P&C	Unverified	3,429	3,420	3,410	3,401	3,401	3,401	3,401	3,401	3,401	3,394		0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
22	Save on Energy Heating and Cooling Program	Verified	517,836	517,836	517,836	517,836	517,836	517,836	517,836	517,836	517,836	517,836		152	152	152	152	152	152	152	152	152	152	100.00%								100%
	Adjustment to 2017 savings in P&C	Unverified	40,215	40,215	40,215	40,215	40,215	40,215	40,215	40,215	40,215	40,215		12	12	12	12	12	12	12	12	12	12	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23	Save on Energy New Construction Program	Verified	502,252	502,252	502,252	502,252	502,252	502,252	502,252	502,252	502,252	502,252		116	116	116	116	116	116	116	116	116	116	100.00%								100%
	Adjustment to 2017 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24	Save on Energy Instant Discount Program	Verified	2,913,183	2,109,693	2,109,693	2,109,693	2,109,693	2,109,693	2,109,693	2,109,652	2,109,652	2,109,652		200	146	146	146	146	146	146	146	146	146	100.00%								100%
	Adjustment to 2017 savings	True-up																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Non-Residential Province-Wide Programs																															
25	Save on Energy Audit Funding Program	Verified											12																			0%
	Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26	Save on Energy Retrofit Program	Verified	3,292,820	3,293,493	3,293,493	3,293,493	3,293,493	3,171,619	3,171,619	3,171,619	3,047,335	3,047,335	12	538	538	538	538	538	518	518	518	517	517		17.35%	44.16%	27.35%	0.00%				89%
	Adjustment to 2017 savings in P&C	Unverified	532,154	531,277	530,400	529,523	529,523	509,928	509,928	509,928	489,946	489,946	12	87	87	87	86	86	83	83	83	83	83	0.00%	17.35%	44.16%	27.35%	0.00%	0.00%	0.00%	0.00%	
27	Save on Energy Small Business Lighting Program	Verified	1,228	1,228	1,228	1,228	1,228	72	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0		100.00%							100%
	Adjustment to 2017 savings	True-up											12											0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28	Save on Energy High Performance New Construction Program	Verified	4,696,753	4,696,753	4,696,753	4,696,753	4,696,753	4,696,753	4,696,753	4,696,753	4,696,753	4,696,753	12	701	701	701	701	701	701	701	701	701	701		0.00%	100.00%	0.00%	0.00%				100%
	Adjustment to 2017 savings	True-up											12											0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
32	Save on Energy Energy Manager Program	Verified	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	1,305	12	0	0	0	0	0	0	0	0	0	0		0.00%	0.00%	0.00%	0.00%				0%
	Adjustment to 2017 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Pilot Programs																															
36	Pool Saver Local Program	Verified	288,132	288,132	288,132	288,132	288,132	288,132	288,132	288,132	288,132	288,132	12	55	55	55	55	55	55	55	55	55	55	100.00%								100%
	Adjustment to 2017 savings in P&C	Unverified	222	222	222	222	222	222	222	222	222	222	12	0	0	0	0	0	0	0	0	0	0	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
37	Whole Home Pilot Program	Verified	52,789	52,789	52,789	52,789	52,229	51,559	51,559	51,559	51,559	51,559	12	7	7	7	7	6	6	6	6	6	6	100.00%								100%
	Adjustment to 2017 savings	True-up											12											100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
38	Smart Thermostat	Verified											12											100.00%								100%
	Adjustment to 2017 savings in P&C	Unverified	26,917	26,917	26,917	26,917	26,917	26,917	26,917	26,917	26,917	26,917	12											100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

	Net Energy Savings (kWh)	Net Demand Savings (kW)	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Actual CDM Savings in 2017	**16,520,950**	**2,120**	**7,996,689**	**664,930**	**11,724**	**2,051**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2017			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Distribution Rate in 2017			$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2017 from 2011 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2012 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2013 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2014 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2015 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2016 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2017 from 2017 programs			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2017			**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2017			**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2017											**$0.00**
2017 Savings Persisting in 2018			6,473,278	664,895	11,723	2,051	0	0	0	0	
2017 Savings Persisting in 2019			6,473,268	664,742	11,722	2,050	0	0	0	0	
2017 Savings Persisting in 2020			6,473,259	664,590	11,722	2,050	0	0	0	0	
2017 Savings Persisting in 2021			6,472,699	664,590	11,722	2,050	0	0	0	0	
2017 Savings Persisting in 2022			6,472,029	638,887	11,599	1,974	0	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-d. 2018 Lost Revenues Work Form

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Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA								
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Conservation First Framework																															
Residential Province-Wide Programs																															
22 Save on Energy Heating and Cooling Program	P&C report	239,378	239,378	239,378	239,378	239,378	239,378	239,378	239,378	239,378	239,378												100.00%								100%
Adjustment to 2018 savings	Post P&C																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
23 Save on Energy New Construction Program	P&C report	1,234,191	1,234,191	1,234,191	1,234,191	1,234,191	1,234,191	1,234,191	1,234,167	1,234,167	1,234,167												100.00%								100%
Adjustment to 2018 savings	Post P&C																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
24 Save on Energy Home Assistance Program	P&C report	1,248,641	1,243,508	1,238,376	1,238,376	1,238,376	1,238,376	1,238,376	1,238,365	1,238,365	1,235,759												100.00%								100%
Adjustment to 2018 savings	Post P&C																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Non-Residential Province-Wide Programs																															
26 Save on Energy Retrofit Program	P&C report	4,462,251	4,451,218	4,440,185	4,440,185	4,440,185	4,440,185	4,440,185	4,440,185	4,440,185	4,440,185	12	775	775	773	773	773	773	745	745	745	743		20.18%	31.35%	43.64%	0.54%				96%
Adjustment to 2018 savings	Post P&C	2,497,759	2,491,584	2,485,408	2,485,408	2,485,408	2,393,436	2,393,436	2,393,436	2,299,647	2,299,647	12	434	434	433	433	433	433	417	417	417	416	0.00%	20.18%	31.35%	43.64%	0.54%	0.00%	0.00%	0.00%	
27 Save on Energy Small Business Lighting Program	P&C report	3,723	3,059	2,394	2,394	2,394	140	0	0	0	0	12												100.00%							100%
Adjustment to 2018 savings	Post P&C											12											0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
28 Save on Energy High Performance New Construction Program	P&C report	865,762	861,466	857,171	857,171	857,171	857,171	857,171	857,171	857,171	857,171	12	106	106	106	106	106	106	106	106	106	106		0.00%	100.00%	0.00%	0.00%				100%
Adjustment to 2018 savings	Post P&C											12											0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
30 Save on Energy Process & Systems Upgrades Program	P&C report											12												0.00%	0.00%	100.00%	0.00%				100%
Adjustment to 2018 savings	Post P&C	399,242	399,242	399,242	399,242	399,242	399,242	399,242	399,242	360,202	360,202	12	22	22	22	22	22	22	22	22	20	20	0.00%	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	
42 Smart Thermostat Program	P&C report	101,036	101,036	101,036	101,036	101,036	101,036	101,036	101,036	101,036	101,036												100.00%								100%
Adjustment to 2018 savings	Post P&C																						100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
43 Pool Program	P&C report	147,729	147,729	147,729	147,729	147,729	147,729	147,729	147,729	147,729	147,729	12											100.00%								100%
Adjustment to 2018 savings	Post P&C											12											100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2018		**11,199,712**											**1,337**										**2,970,975**	**1,408,162**	**5,822**	**6,592**	**79**	**0**	**0**	**0**	
Forecast CDM Savings in 2018																							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Distribution Rate in 2018	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2018 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2018 from 2018 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2018	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2018	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2018									**$0.00**
2018 Savings Persisting in 2019	2,965,842	1,404,025	5,822	6,592	79	0	0	0	
2018 Savings Persisting in 2020	2,960,710	1,399,887	5,804	6,576	78	0	0	0	
2018 Savings Persisting in 2021	2,960,710	1,399,887	5,804	6,576	78	0	0	0	
2018 Savings Persisting in 2022	2,960,710	1,399,887	5,804	6,576	78	0	0	0	

Note: LDC to make note of key assumptions included above

Table 5-e. 2019 Lost Revenues Work Form

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Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA								
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Conservation First Framework																															
Non-Residential Province-Wide Programs																															
26 Save on Energy Retrofit Program	P&C report	15,200	15,200	15,203	15,203	15,203	15,203	14,641	14,641	14,641	14,067	12	2	2	2	2	2	2	2	2	2	2		20.18%	31.35%	43.64%	0.54%				96%
Adjustment to 2019 savings	Post P&C	3,299,217	3,299,217	3,299,891	3,299,891	3,299,891	3,299,891	3,177,780	3,177,780	3,177,780	3,053,255	12	394	394	394	394	394	380	380	380	379	379	0.00%	20.18%	31.35%	43.64%	0.54%	0.00%	0.00%	0.00%	
Save on Energy Retrofit Program - Metered Street Lights	P&C report											12												100.00%	0.00%	0.00%	0.00%				100%
Adjustment to 2019 savings	Post P&C	0	121,260	409,646	411,935							12	0	29	99	99							0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Save on Energy Retrofit Program - Unmetered Street Lights	P&C report											12												0.00%	0.00%	0.00%	0.00%			100.00%	100%
Adjustment to 2019 savings	Post P&C	883,315	1,461,959	1,173,573	1,171,284							12	213	353	283	283							0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
27 Save on Energy Small Business Lighting Program	P&C report	143,593	126,434	126,434	126,434	126,434	7,413	0	0	0	0	12												100.00%							100%
Adjustment to 2019 savings	Post P&C											12											0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2019		**4,341,325**											**609**										**0**	**812,399**	**1,490**	**2,074**	**26**	**0**	**0**	**2,560**	
Forecast CDM Savings in 2019																							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Distribution Rate in 2019	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2019 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Lost Revenue in 2019 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2018 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2019 from 2019 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2019	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2019	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2019									**$0.00**
2019 Savings Persisting in 2020	-	916,500	1,490	2,074	26	-	-	4,237	
2019 Savings Persisting in 2021	-	1,205,023	1,490	2,074	26	-	-	3,401	
2019 Savings Persisting in 2022	-	1,207,312	1,490	2,074	26	-	-	3,394	

Note: LDC to make note of key assumptions included above

Table 5-f. 2020 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA								
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Conservation First Framework																															
Non-Residential Province-Wide Programs																															
25 Save on Energy Audit Funding Program	Verified											12																			0%
Adjustment to 2020 savings	True-up											12											0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
26 Save on Energy Retrofit Program	P&C											12																			0%
Adjustment to 2020 savings	Post P&C	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Save on Energy Retrofit Program - Metered	P&C											12												100.00%							100%
Adjustment to 2020 savings	Post P&C	44,115	482,041	498,270								12	11	116	120								0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Save on Energy Retrofit Program -	P&C											12																		100.00%	100%
Adjustment to 2020 savings	Post P&C	671,452	362,183	345,954								12	162	87	84								0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	
Actual CDM Savings in 2020		**715,566**											**173**										**0**	**715,566**	**0**	**0**	**0**	**0**	**0**	**1,946**	
Forecast CDM Savings in 2020																							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Total
Distribution Rate in 2020	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
Lost Revenue in 2020 from 2011 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2012 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2013 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2014 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2015 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2016 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2017 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2018 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2019 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Lost Revenue in 2020 from 2020 programs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Lost Revenues in 2020	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Forecast Lost Revenues in 2020	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
LRAMVA in 2020									**$0.00**
2020 Savings Persisting in 2021	-	844,224.11	-	-	-	-	-	1,049.55	
2020 Savings Persisting in 2022	-	844,224.11	-	-	-	-	-	1,002.52	

Note: LDC to make note of key assumptions included above

Table 5-g. 2021 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA								
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	0
Conservation First Framework																															
Non-Residential Province-Wide Programs																															
26 Save on Energy Retrofit Program	P&C											12																			0%
Adjustment to 2021 savings	Post P&C	50,201	50,201									12	18	18									0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual CDM Savings in 2021		**50,201**											**18**										**0**	**0**	**211**	**0**	**0**	**0**	**0**	**0**	
Forecast CDM Savings in 2021																							**1,633,000**	**767,647**	**7,932**	**1,669**	**416**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	0
Distribution Rate in 2021	$0.00000	$0.01870	$3.23250	$2.26620	$1.57110	$0.01790	$41.06360	$11.30520	
Lost Revenue in 2021 from 2011 programs									$0.00
Lost Revenue in 2021 from 2012 programs									$0.00
Lost Revenue in 2021 from 2013 programs									$0.00
Lost Revenue in 2021 from 2014 programs									$0.00
Lost Revenue in 2021 from 2015 programs	$0.00	$29,567.90	$1,451.91	$1,854.02	$12,577.91	$0.00	$0.00	$0.00	$45,451.75
Lost Revenue in 2021 from 2016 programs	$0.00	$31,032.47	$13,501.40	$3,046.24	$10.61	$0.00	$0.00	$0.00	$47,590.71
Lost Revenue in 2021 from 2017 programs	$0.00	$12,427.84	$37,890.20	$4,645.05	$0.00	$0.00	$0.00	$0.00	$54,963.09
Lost Revenue in 2021 from 2018 programs	$0.00	$26,177.89	$18,761.91	$14,903.39	$123.25	$0.00	$0.00	$0.00	$59,966.45
Lost Revenue in 2021 from 2019 programs	$0.00	$22,533.93	$4,814.98	$4,700.10	$40.47	$0.00	$0.00	$38,447.04	$70,536.52
Lost Revenue in 2021 from 2020 programs	$0.00	$15,786.99	$0.00	$0.00	$0.00	$0.00	$0.00	$11,865.37	$27,652.36
Lost Revenue in 2021 from 2021 programs	$0.00	$0.00	$682.99	$0.00	$0.00	$0.00	$0.00	$0.00	$682.99
Total Lost Revenues in 2021	**$0.00**	**$137,527.02**	**$77,103.38**	**$29,148.81**	**$12,752.24**	**$0.00**	**$0.00**	**$50,312.41**	**$306,160.88**
Forecast Lost Revenues in 2021	**$0.00**	**$14,355.00**	**$25,641.26**	**$3,781.82**	**$653.11**	**$0.00**	**$0.00**	**$0.00**	**$44,431.19**
LRAMVA in 2021									**$261,729.69**
2021 Savings Persisting in 2022	-	-	211.29	-	-	-	-	-	

Note: LDC to make note of key assumptions included above

Table 5-h. 2022 Lost Revenues Work Form Return to top

Program	Results Status	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)									Monthly Multiplier	Net Demand Savings (kW)	Net Peak Demand Savings Persistence (kW)									Rate Allocations for LRAMVA								
		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	0
Actual CDM Savings in 2022		**100,401**											**35**																		
Forecast CDM Savings in 2022																							**1,633,000**	**767,647**	**7,932**	**1,669**	**416**	**0**	**0**	**0**	

	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	0
Distribution Rate in 2022	$0.00000	$0.01920	$3.32260	$2.32940	$1.61490	$0.01840	$42.20850	$11.62040	
Lost Revenue in 2022 from 2011 programs									$0.00
Lost Revenue in 2022 from 2012 programs									$0.00
Lost Revenue in 2022 from 2013 programs									$0.00
Lost Revenue in 2022 from 2014 programs									$0.00
Lost Revenue in 2022 from 2015 programs	$0.00	$30,358.49	$1,492.38	$1,905.72	$12,928.57	$0.00	$0.00	$0.00	$46,685.16
Lost Revenue in 2022 from 2016 programs	$0.00	$31,862.21	$13,877.72	$3,131.20	$10.90	$0.00	$0.00	$0.00	$48,882.04
Lost Revenue in 2022 from 2017 programs	$0.00	$12,266.63	$38,537.52	$4,597.10	$0.00	$0.00	$0.00	$0.00	$55,401.25
Lost Revenue in 2022 from 2018 programs	$0.00	$26,877.84	$19,284.87	$15,319.02	$126.69	$0.00	$0.00	$0.00	$61,608.41
Lost Revenue in 2022 from 2019 programs	$0.00	$23,180.39	$4,949.19	$4,831.18	$41.59	$0.00	$0.00	$39,441.90	$72,444.25
Lost Revenue in 2022 from 2020 programs	$0.00	$16,209.10	$0.00	$0.00	$0.00	$0.00	$0.00	$11,649.67	$27,858.77
Lost Revenue in 2022 from 2021 programs	$0.00	$0.00	$702.02	$0.00	$0.00	$0.00	$0.00	$0.00	$702.02
Total Lost Revenues in 2022	**$0.00**	**$140,754.66**	**$78,843.70**	**$29,784.22**	**$13,107.76**	**$0.00**	**$0.00**	**$51,091.57**	**$312,879.88**
Forecast Lost Revenues in 2022	**$0.00**	**$14,738.82**	**$26,355.96**	**$3,887.28**	**$671.32**	**$0.00**	**$0.00**	**$0.00**	**$45,653.39**
LRAMVA in 2022									**$267,226.49**

Note: LDC to make note of key assumptions included above

Ontario Energy Board

LRAMVA Work Form:
Carrying Charges by Rate Class

Version 6.0 (2022)

Legend

User Inputs (Green)
Auto Populated Cells (White)
Instructions (Grey)

Instructions

1. Please update Table 6 as new approved prescribed interest rates for deferral and variance accounts become available. Monthly interest rates are used to calculate the variance on the carrying charges for LRAMVA. Starting from column I, the principal will auto-populate as monthly variances in Table 6-a, and are multiplied by the interest rate from column H to determine the monthly variances on carrying charges for each rate class by year.

2. The annual carrying charges totals in Table 6-a below pertain to the amount that was originally collected in interest from forecasted CDM savings and what should have been collected based on actual CDM savings. As the amounts calculated in Table 6-a are cumulative, LDCs are requested to enter any collected interest amounts into the "Amounts Cleared" row in order to clear the balance and calculate outstanding variances on carrying charges.

3. Please calculate the projected interest amounts in the LRAMVA work form. Project carrying charges amounts incuded in Table 6-a should be consistent with the projected interest amounts included in the DVA Continuity Schedule. **If there are additional adjustments required to the formulas to calculate the projected interest amounts, please adjust the formulas in Table 6-a accordingly.**

Table 6. Prescribed Interest Rates

Quarter	Approved Deferral & Variance Accounts
2011 Q1	1.47%
2011 Q2	1.47%
2011 Q3	1.47%
2011 Q4	1.47%
2012 Q1	1.47%
2012 Q2	1.47%
2012 Q3	1.47%
2012 Q4	1.47%
2013 Q1	1.47%
2013 Q2	1.47%
2013 Q3	1.47%
2013 Q4	1.47%
2014 Q1	1.47%
2014 Q2	1.47%
2014 Q3	1.47%
2014 Q4	1.47%
2015 Q1	1.47%
2015 Q2	1.10%
2015 Q3	1.10%
2015 Q4	1.10%
2016 Q1	1.10%
2016 Q2	1.10%
2016 Q3	1.10%
2016 Q4	1.10%
2017 Q1	1.10%
2017 Q2	1.10%
2017 Q3	1.10%
2017 Q4	1.50%
2018 Q1	1.50%
2018 Q2	1.89%
2018 Q3	1.89%
2018 Q4	2.17%
2019 Q1	2.45%
2019 Q2	2.18%
2019 Q3	2.18%
2019 Q4	2.18%
2020 Q1	2.18%
2020 Q2	2.18%
2020 Q3	0.57%
2020 Q4	0.57%
2021 Q1	0.57%
2021 Q2	0.57%
2021 Q3	0.57%
2021 Q4	0.57%
2022 Q1	0.57%
2022 Q2	0.57%
2022 Q3	0.57%
2022 Q4	0.57%
2023 Q1	
2023 Q2	
2023 Q3	
2023 Q4	
2024 Q1	
2024 Q2	
2024 Q3	
2024 Q4	
2025 Q1	
2025 Q2	
2025 Q3	
2025 Q4	

Check OEB website

Table 6-a. Calculation of Carrying Costs by Rate Class

Go to Tab 1: Summary

Month	Period	Quarter	Monthly Rate	Residential	GS<50 kW	GS 50 to 999 kW	GS 1,000 to 4,999 kW	Large Use	Unmetered Scattered Load	Sentinel Lighting	Street Lighting							Total
Jan-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-11	2011	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-11	2011	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-11	2011	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-11	2011	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2011				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-12	2011-2012	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-12	2011-2012	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-12	2011-2012	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-12	2011-2012	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2012				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2013				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-13	2011-2013	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-13	2011-2013	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-13	2011-2013	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-13	2011-2013	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2013				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2014				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-14	2011-2014	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-14	2011-2014	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-14	2011-2014	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-14	2011-2014	Q2	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-14	2011-2014	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-14	2011-2014	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-14	2011-2014	Q3	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-14	2011-2014	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-14	2011-2014	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-14	2011-2014	Q4	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2014				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2015				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-15	2011-2015	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-15	2011-2015	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-15	2011-2015	Q1	0.12%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-15	2011-2015	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-15	2011-2015	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-15	2011-2015	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Jul-15	2011-2015	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-15	2011-2015	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-15	2011-2015	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-15	2011-2015	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-15	2011-2015	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-15	2011-2015	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2015				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2016				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-16	2011-2016	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-16	2011-2016	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-16	2011-2016	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-16	2011-2016	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-16	2011-2016	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-16	2011-2016	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-16	2011-2016	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-16	2011-2016	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-16	2011-2016	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-16	2011-2016	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-16	2011-2016	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-16	2011-2016	Q4	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2016				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2017				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-17	2011-2017	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-17	2011-2017	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-17	2011-2017	Q1	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-17	2011-2017	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-17	2011-2017	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-17	2011-2017	Q2	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-17	2011-2017	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-17	2011-2017	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-17	2011-2017	Q3	0.09%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-17	2011-2017	Q4	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-17	2011-2017	Q4	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-17	2011-2017	Q4	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2017				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2018				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-18	2011-2018	Q1	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-18	2011-2018	Q1	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-18	2011-2018	Q1	0.13%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-18	2011-2018	Q2	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-18	2011-2018	Q2	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-18	2011-2018	Q2	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-18	2011-2018	Q3	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-18	2011-2018	Q3	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-18	2011-2018	Q3	0.16%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-18	2011-2018	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-18	2011-2018	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-18	2011-2018	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2018				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2019				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-19	2011-2019	Q1	0.20%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-19	2011-2019	Q1	0.20%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-19	2011-2019	Q1	0.20%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-19	2011-2019	Q2	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-19	2011-2019	Q2	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-19	2011-2019	Q2	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-19	2011-2019	Q3	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-19	2011-2019	Q3	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-19	2011-2019	Q3	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-19	2011-2019	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-19	2011-2019	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-19	2011-2019	Q4	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2019				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2020				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Jan-20	2011-2020	Q1	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Feb-20	2011-2020	Q1	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Mar-20	2011-2020	Q1	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Apr-20	2011-2020	Q2	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
May-20	2011-2020	Q2	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jun-20	2011-2020	Q2	0.18%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Jul-20	2011-2020	Q3	0.05%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Aug-20	2011-2020	Q3	0.05%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Sep-20	2011-2020	Q3	0.05%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Oct-20	2011-2020	Q4	0.05%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Nov-20	2011-2020	Q4	0.05%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Dec-20	2011-2020	Q4	0.05%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total for 2020				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Amount Cleared																		
Opening Balance for 2021				**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**

Ontario Energy Board

Supporting Documentation:
LDC Persistence Savings Results from IESO

Version 6.0 (2022)

Legend

- User Inputs (Green)
- Drop Down List (Blue)
- Instructions (Grey)

Instructions
(Steps)

1. Columns B to H of this tab have been structured in a way to match the formatting of the persistence report provided by the IESO. Please copy and paste the program information by initiative in Columns B to H and the corresponding demand and energy savings data by initiative in Columns L to BT of this work form.
2. Please identify the source of the report via the dropdown list in Column I.
3. To faciliate the identification of adjustments that may be available in a prospective year's results report, it will be easier to sort all the savings by implementation year (Column H). This can be done by clicking on the filter button at cell H25 (highlighted in orange). Before you sort values, please ensure that all table columns have filters.
4. Please identify what the savings value represents (i.e., current year savings for the year or an adjustment to a prior year) via the dropdown list in Column J. Current year savings would be identified with an implementation year that matches the year of the persistence report. A savings adjustment would be identified with a prior year implementation in the future year's results report.
5. Please manually input or link the applicable savings and adjustments (Columns L to BT) for all applicable initiatives in Tabs 4 and 5 of this work form.
NOTE: The Net Verified Peak Demand Savings table and Net Verified Energy Savings table below are in the reverse order to the accompanying tables in Tab 4 and Tab 5. The tables below match those provided by the IESO.

Table 7. 2011-2020 Verified Program Results and Persistence into Future Years

Step:	*#1*					*#3*	*#2*	*#4*
Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	(Implementation) Year	Identify Source of Report	Identify Status of Savings

#1

Net Verified Annual Peak Demand Savings at the End-User Level (kW)																													
###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###

#1

Net Verified Annual Energy Savings at the End-User Level (kWh)																													
###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###	###

Ontario Energy Board

LRAMVA Work Form: Documentation for Streetlighting Projects

Version 6.0 (2022)

Legend User Inputs (Green)

Instructions

Please provide documentation and/or data to substantiate program savings that were not provided in the IESO's verified results reports (i.e., streetlighting projects).

Distributors are encouraged to provide data in the following format, and complete a separate set of following tables for each project. The tables below are meant to be an example. Distributors should complete the tables based on the actual project details. Please create the necessary links to Tab 4/5 and tabulations within this LRAMVA workform to calculate the LRAMVA amounts. Alternatively, LDCs may submit a separate attachment with the project level details for billed demand by type of bulb.

Table 8-a 2019 Streetlighting savings summary (net)

Program	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)			Monthly multiplier	Net Demand Savings (kW)	Net Demand Savings Persistence (kW)			Allocation	
	2019	2020	2021	2022		2019	2020	2021	2022	GS<50 kW	Street Lighting
Retrofit (Streetlights metered)	-	121,260	409,646	411,935	12	-	29.3	98.9	99.5	100%	
Retrofit (Streetlights unmetered)	883,315	1,461,959	1,173,573	1,171,284	12	213.3	353.0	283.4	282.8		100%
Retrofit (All streetlighting projects)	883,315	1,583,219	1,583,219	1,583,219	12	213.3	382.3	382.3	382.3		

Source: Summary of Table 8-f below, multiplied by NTG from 2017 final results report for MHDI

Retrofit Demand Net to Gross 0.870550162

Retrofit Energy Net to Gross 0.858323969

Table 8-b 2020 Streetlight savings summary (net)

Program	Net Energy Savings (kWh)	Net Energy Savings Persistence (kWh)			Monthly multiplier	Net Demand	Net Demand Savings Persistence (kW)			Allocation	
	2020	2021	2022	2023		2020	2021	2022	2023	GS<50 kW	Lighting
Retrofit (Streetlights metered)	44,115	482,041	498,270		12	10.7	116.4	120.3		100%	
Retrofit (Streetlights unmetered)	671,452	362,183	345,954		12	162.1	87.5	83.5			100%
Retrofit (All streetlighting projects)	715,566	844,224	844,224		12	172.8	203.9	203.9			

Source: Summary of Table 8-f below, multiplied by NTG from 2017 final results report for MHDI

Table 8-c Raw data on fixtures changes

Customer	Billing change month	Year	Old bulb type	Billed wattage	New bulb type	New wattage	kW savings	kWh savings	Add metering
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-134	134	166	697.2	Aug 2020
REGION OF HALTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-213	213	87	365.4	Mar 2021
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-200	245	Smart LED-68	68	177	743.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-200	245	Smart LED-68	68	177	743.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
REGION OF HALTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Nov 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
REGION OF HALTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-134	134	166	697.2	Jun 2020
REGION OF HALTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-134	134	166	697.2	Mar 2021
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-134	134	166	697.2	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019	Cobra HPS-250	300	Smart LED-68	68	232	974.4	

Table 8-d Projects in 2019

Billing change	Energy savings (kWh)	Demand savings (kW)	Billed by kWh	Billed by kW
Jan 2019	29,367	83.9	-	83.9
Feb 2019	29,367	83.9	-	83.9
Mar 2019	29,367	83.9	-	83.9
Apr 2019	29,367	83.9	-	83.9
May 2019	55,999	160.0	-	160.0
Jun 2019	79,391	226.8	-	226.8
Jul 2019	116,039	331.5	-	331.5
Aug 2019	119,943	342.7	-	342.7
Sep 2019	128,553	367.3	-	367.3
Oct 2019	129,006	368.6	-	368.6
Nov 2019	129,006	368.6	-	368.6
Dec 2019	153,712	439.2	-	439.2
Jan 2020	153,712	439.2	-	439.2
Feb 2020	153,712	439.2	-	439.2
Mar 2020	153,712	439.2	-	439.2
Apr 2020	153,712	439.2	-	439.2
May 2020	153,712	439.2	-	439.2
Jun 2020	153,712	439.2	6,025	422.0
Jul 2020	153,712	439.2	6,428	420.8
Aug 2020	153,712	439.2	16,975	390.7
Sep 2020	153,712	439.2	19,573	383.3
Oct 2020	153,712	439.2	26,059	364.7
Nov 2020	153,712	439.2	32,292	346.9
Dec 2020	153,712	439.2	33,923	342.3
Jan 2021	153,712	439.2	37,549	331.9
Feb 2021	153,712	439.2	39,773	325.5
Mar 2021	153,712	439.2	39,994	324.9
Apr 2021	153,712	439.2	39,994	324.9
May 2021	153,712	439.2	39,994	324.9
Jun 2021	153,712	439.2	39,994	324.9
Jul 2021	153,712	439.2	39,994	324.9
Aug 2021	153,712	439.2	39,994	324.9
Sep 2021	153,712	439.2	39,994	324.9
Oct 2021	153,712	439.2	39,994	324.9
Nov 2021	153,712	439.2	39,994	324.9
Dec 2021	153,712	439.2	39,994	324.9
Jan 2022	153,712	439.2	39,994	324.9
Feb 2022	153,712	439.2	39,994	324.9
Mar 2022	153,712	439.2	39,994	324.9
Apr 2022	153,712	439.2	39,994	324.9
May 2022	153,712	439.2	39,994	324.9
Jun 2022	153,712	439.2	39,994	324.9
Jul 2022	153,712	439.2	39,994	324.9
Aug 2022	153,712	439.2	39,994	324.9
Sep 2022	153,712	439.2	39,994	324.9
Oct 2022	153,712	439.2	39,994	324.9
Nov 2022	153,712	439.2	39,994	324.9
Dec 2022	153,712	439.2	39,994	324.9

Source: Calculated from Table 8-c

Note: savings are cumulative amounts. First year energy savings are divided by 12 to get monthly amounts

Table 8-e Projects in 2020

Billing change	Energy savings (kWh)	Demand savings (kW)	Billed by kWh	Billed by kW
Jan 2020	16,419	46.9	-	46.9
Feb 2020	25,182	71.9	-	71.9
Mar 2020	66,088	188.8	-	188.8
Apr 2020	77,392	221.1	-	221.1
May 2020	80,778	230.8	-	230.8
Jun 2020	80,778	230.8	5	230.8
Jul 2020	80,778	230.8	5	230.8
Aug 2020	80,778	230.8	5	230.8
Sep 2020	80,778	230.8	63	230.6
Oct 2020	80,778	230.8	5,220	215.9
Nov 2020	81,964	234.2	18,258	182.0
Dec 2020	81,964	234.2	27,841	154.6
Jan 2021	81,964	234.2	30,217	147.9
Feb 2021	81,964	234.2	47,627	98.1
Mar 2021	81,964	234.2	48,376	96.0
Apr 2021	81,964	234.2	48,376	96.0
May 2021	81,964	234.2	48,376	96.0
Jun 2021	81,964	234.2	48,376	96.0
Jul 2021	81,964	234.2	48,376	96.0
Aug 2021	81,964	234.2	48,376	96.0
Sep 2021	81,964	234.2	48,376	96.0
Oct 2021	81,964	234.2	48,376	96.0
Nov 2021	81,964	234.2	48,376	96.0
Dec 2021	81,964	234.2	48,376	96.0
Jan 2022	81,964	234.2	48,376	96.0
Feb 2022	81,964	234.2	48,376	96.0
Mar 2022	81,964	234.2	48,376	96.0
Apr 2022	81,964	234.2	48,376	96.0
May 2022	81,964	234.2	48,376	96.0
Jun 2022	81,964	234.2	48,376	96.0
Jul 2022	81,964	234.2	48,376	96.0
Aug 2022	81,964	234.2	48,376	96.0
Sep 2022	81,964	234.2	48,376	96.0
Oct 2022	81,964	234.2	48,376	96.0
Nov 2022	81,964	234.2	48,376	96.0
Dec 2022	81,964	234.2	48,376	96.0

Source: Calculated from Table 8-c

Note: savings are cumulative amounts. First year energy savings are divided by 12 to get monthly amounts

Table 8-f Annual summary of 2019 projects (gross)

Annual Summary	Energy Savings (kWh)	Demand savings (kW)	Metered SL (kWh)	Unmetered SL (kW)
2019	1,029,116	245.0	-	245.0
2020	1,844,548	439.2	141,275	405.5
2021	1,844,548	439.2	477,263	325.5
2022	1,844,548	439.2	479,930	324.9

Source: Calculated from Table 8-d above

Note: demand savings are divided by 12 to get average amounts

Table 8-g Annual summary of 2020 projects (gross)

Annual Summary	Energy Savings (kWh)	Demand savings (kW)	Metered SL (kWh)	Unmetered SL (kW)
2020	833,679	198.5	51,396	186.3
2021	983,573	234.2	561,607	100.5
2022	983,573	234.2	580,516	96.0

Source: Calculated from Table 8-e above

Note: demand savings are divided by 12 to get average amounts

TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-200	245	Smart LED-68	68	177	743.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-213	213	257	1079.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-100	100	95	399	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-200	245	Smart LED-68	68	177	743.4	
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-213	213	87	365.4	
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-213	213	87	365.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-213	213	87	365.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-213	213	87	365.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	Aug 2020
REGION OF HALTON	Jan 2019	2019 Cobra HPS-150	195	Smart LED-68	68	127	533.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	

TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	Mar 2021
REGION OF HALTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	Dec 2020
REGION OF HALTON	Jan 2019	2019 Cobra HPS-200	245	Smart LED-213	213	32	134.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-200	245	Smart LED-100	100	145	609	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-200	245	Smart LED-100	100	145	609	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-200	245	Smart LED-100	100	145	609	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-200	245	Smart LED-68	68	177	743.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-200	245	Smart LED-68	68	177	743.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-100	100	200	840	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-250	300	Smart LED-68	68	232	974.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	Jan 2019	2019 Cobra HPS-400	470	Smart LED-68	68	402	1688.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
REGION OF HALTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020

TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-26	26	109	457.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-400	470	LED-26	26	444	1864.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	

TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-65	65	35	147	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-100	100	35	147	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-65	65	35	147	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-65	65	35	147	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-65	65	35	147	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-65	65	35	147	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-65	65	35	147	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Jul 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	

TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-70	100	Smart LED-58	58	42	176.4	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	May 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	HPS-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-68	68	67	281.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	

TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-100	100	200	840	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-100	100	200	840	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-100	100	200	840	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-100	100	200	840	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-100	100	200	840	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	

TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-162	162	33	138.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-200	245	LED-86	86	159	667.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	

TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-162	162	-27	-113.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-162	162	-27	-113.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-162	162	-27	-113.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-162	162	-27	-113.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-162	162	-27	-113.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-162	162	-27	-113.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-162	162	-27	-113.4	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	Smart LED-86	86	49	205.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	Jun 2020
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jun 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	

TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jul 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-117	117	183	768.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-117	117	183	768.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-117	117	183	768.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-117	117	183	768.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-117	117	183	768.6	
REGION OF HALTON	Jul 2019	2019 Cobra HPS-250	300	LED-117	117	183	768.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-65	65	35	147	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-65	65	35	147	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	

TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-26	26	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	Smart LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	Smart LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	Smart LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	Smart LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	Smart LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	Smart LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	Smart LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	Smart LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Nov 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Nov 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Nov 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	Nov 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Nov 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	Nov 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	

TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	Jun 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	Smart LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	Aug 2020
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-58	58	242	1016.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	

TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	Smart LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	Smart LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-200	245	LED-86	86	159	667.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	Smart LED-58	58	77	323.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-100	135	LED-58	58	77	323.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4

TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4	
TOWN OF MILTON	Jul 2019	2019 Cobra HPS-70	100	LED-28	28	72	302.4	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-100	100	200	840	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-100	100	200	840	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-100	100	200	840	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-250	300	LED-100	100	200	840	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	Smart LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Aug 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	Jun 2020
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	-162	162	138	579.6	

TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	Smart LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-162	162	33	138.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-65	65	235	987	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	-86	86	49	205.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-134	134	61	256.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-100	135	LED-65	65	70	294	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-400	470	LED-86	86	384	1612.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-400	470	LED-86	86	384	1612.8	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	Smart LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra LED-48	48	LED-86	86	-38	-159.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Aug 2020
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	

TOWN OF MILTON	Oct 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-250	300	LED-162	162	138	579.6	Sep 2020
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-158	158	142	596.4	
TOWN OF MILTON	Sep 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Oct 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Oct 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-400	470	LED-86	86	384	1612.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-100	135	LED-26	26	109	457.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-26	26	74	310.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-58	58	42	176.4	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020

REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-400	470	LED-213	213	257	1079.4	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-150	195	LED-213	213	-18	-75.6	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-400	470	LED-213	213	257	1079.4	Oct 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Jan 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Mar 2021
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020

REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-221	221	LED-86	86	135	567	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra LED-147	147	LED-86	86	61	256.2	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Dec 2019	2019 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-200	245	LED-86	86	159	667.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-162	162	33	138.6	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-162	162	33	138.6	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-162	162	33	138.6	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-162	162	33	138.6	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-162	162	33	138.6	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-162	162	33	138.6	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-162	162	33	138.6	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	

TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-400	470	LED-213	213	257	1079.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-400	470	LED-213	213	257	1079.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra INC-69	69	LED-213	213	-144	-604.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-400	470	LED-213	213	257	1079.4	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-400	470	LED-213	213	257	1079.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Nov 2020
TOWN OF MILTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Jun 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-147	147	LED-134	134	13	54.6	Nov 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra INC-69	69	LED-86	86	-17	-71.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-400	470	LED-180	180	290	1218	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra INC-69	69	LED-86	86	-17	-71.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Feb 2021
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	Smart LED-86	86	214	898.8	
REGION OF HALTON	Jan 2020	2020 Cobra LED-190	190	Smart LED-86	86	104	436.8	
REGION OF HALTON	Jan 2020	2020 Cobra LED-190	190	Smart LED-86	86	104	436.8	
REGION OF HALTON	Jan 2020	2020 Cobra LED-190	190	Smart LED-86	86	104	436.8	
REGION OF HALTON	Jan 2020	2020 Cobra LED-190	190	Smart LED-86	86	104	436.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Jan 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
REGION OF HALTON	Jan 2020	2020 Cobra LED-190	190	Smart LED-86	86	104	436.8	
REGION OF HALTON	Jan 2020	2020 Cobra LED-190	190	Smart LED-86	86	104	436.8	
REGION OF HALTON	Jan 2020	2020 Cobra LED-190	190	Smart LED-86	86	104	436.8	
REGION OF HALTON	Jan 2020	2020 Cobra LED-190	190	Smart LED-86	86	104	436.8	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-68	68	127	533.4	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-68	68	127	533.4	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-68	68	127	533.4	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-68	68	127	533.4	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-68	68	127	533.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-68	68	127	533.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	LED-68	68	127	533.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-200	245	Smart LED-86	86	159	667.8	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020

REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-134	134	93	390.6	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-200	245	Smart LED-86	86	159	667.8	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-200	245	Smart LED-86	86	159	667.8	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-150	195	Smart LED-86	86	109	457.8	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-200	245	Smart LED-86	86	159	667.8	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra LED-227	227	Smart LED-86	86	141	592.2	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Jan 2021
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Sep 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-400	470	LED-134	134	336	1411.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-400	470	LED-134	134	336	1411.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-68	68	232	974.4	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-68	68	232	974.4	Oct 2020
REGION OF HALTON	Jan 2020	2020 Cobra HPS-250	300	LED-68	68	232	974.4	Oct 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
TOWN OF MILTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021

REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
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REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
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REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
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REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
TOWN OF MILTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
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REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
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REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
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REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
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REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Feb 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Dec 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-400	470	LED-162	162	308	1293.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-400	470	LED-162	162	308	1293.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020

REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-135	135	165	693	
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-135	135	165	693	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-135	135	165	693	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
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REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Oct 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Oct 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Oct 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Oct 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Oct 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-150	195	LED-134	134	61	256.2	Oct 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-150	195	LED-134	134	61	256.2	Oct 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Oct 2020
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!

REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-130	130	170	714	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-170	170	130	546	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-110	110	190	798	Jan 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-400	470	LED-162	162	308	1293.6	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-84	84	216	907.2	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-84	84	216	907.2	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-84	84	216	907.2	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-84	84	216	907.2	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-158	158	142	596.4	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-84	84	216	907.2	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-84	84	216	907.2	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	

REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-92	92	208	873.6	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-92	92	208	873.6	
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
TOWN OF MILTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Dec 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-72	72	228	957.6	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-125	125	175	735	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-96	96	204	856.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-213	213	87	365.4	Nov 2020
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	

REGION OF HALTON	Mar 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-134	134	166	697.2	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	Nov 2020
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	Feb 2021
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	Feb 2021
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-162	162	138	579.6	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	#VALUE!
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	#VALUE!
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-158	158	142	596.4	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-158	158	142	596.4	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-158	158	142	596.4	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-158	158	142	596.4	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-158	158	142	596.4	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-158	158	142	596.4	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-158	158	142	596.4	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-158	158	142	596.4	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-230	230	70	294	Dec 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	Smart LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	

TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-400	470	LED-86	86	384	1612.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-58	58	77	323.4	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-58	58	77	323.4	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Dec 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Dec 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Dec 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Nov 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Dec 2020
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	Dec 2020
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
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REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-70	100	LED-86	86	14	58.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-180	180	120	504	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Feb 2021
REGION OF HALTON	May 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-150	195	LED-86	86	109	457.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
REGION OF HALTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	Jan 2021
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-100	135	LED-86	86	49	205.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
TOWN OF MILTON	Apr 2020	2020 Cobra HPS-250	300	LED-86	86	214	898.8	
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA LED-2	227	Smart LED-208	208	19	79.8	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020

REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-208	208	92	386.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020
REGION OF HALTON	Nov 2020	2020 RCOBRA HPS-2	300	Smart LED-198	198	102	428.4	Oct 2020