EXHIBIT 4 – OPERATING EXPENSES

2022 Cost of Service

Ottawa River Power Corp.
EB-2021-0052

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4.1 OVERVIEW

4.1.1 OVERVIEW

The operating costs found in this exhibit represent expenditures that are required to maintain and operate ORPC's distribution system assets at the targeted levels of performance, to meet customer expectations, ensure public and employee safety and provide quality service. These operating costs are necessary to comply with the Distribution System Code, environmental requirements, and government direction. OM&A expenses consist of, but are not limited to: the required expenditures necessary to maintain and operate ORPC's distribution system assets; the costs associated with metering, billing, and collecting from ORPC's customers; the costs associated with ensuring the safety of all stakeholders; and costs to maintain distribution service quality and reliability.

While preparing its 2021 Bridge and 2022 Test Year budgets, ORPC took into consideration the bill impacts associated with these OM&A costs. For the several iterations of the budget, the bill impacts were analyzed and the OM&A budget modified to minimize bill impacts to the customers as much as possible. ORPC's Board of Directors have met and have been involved in the determining of the final 2021 and 2022 proposed budget and its customer engagement activities.

ORPC's 2022 Test Year operating costs are projected to be $3,708,394 which represents an increase of $643,430 from its 2016 Cost of Service or 19.8%. Details are presented in Table 1 - Total OM&A below.

Table 2 – Appendix 2-JA Total OM&A shows historical and budgeted OM&A costs by major function.

Table 1 - Total OM&A

	2016 Board Approved	2022	Diff
Operations	$529,246	$901,091	$371,844
Maintenance	$673,343	$576,747	-$96,596
Billing and Collecting	$733,000	$962,860	$229,860
Community Relations	$67,000	$42,318	-$24,682
Administrative and General	$1,062,375	$1,225,378	$163,003
Total	**$3,064,964**	**$3,708,394**	**$643,431**

Table 2 – Appendix 2-JA Total OM&A

	Board Approved	2016	2017	2018	2019
Operations	$529,246	$630,729	$565,513	$484,252	$513,327
Maintenance	$673,343	$613,081	$692,292	$500,384	$645,567
Subtotal	**$1,202,589**	**$1,243,810**	**$1,257,805**	**$984,636**	**$1,158,895**
%Change (year over year)		3.4%	1.1%	-21.7%	17.7%
%Change (Test Year vs Last Rebasing Year - Actual)					
Billing and Collecting	$733,000	$747,071	$804,067	$668,041	$748,224
Community Relations	$67,000	$55,936	$79,674	$71,838	$64,147
Administrative and General+LEAP	$1,062,375	$886,993	$1,121,542	$1,076,915	$1,235,810
Subtotal	**$1,862,375**	**$1,690,000**	**$2,005,283**	**$1,816,794**	**$2,048,181**
%Change (year over year)		-44.9%	18.7%	-9.4%	12.7%
%Change (Test Year vs Last Rebasing Year - Actual)					
Total	**$3,064,964**	**$2,933,810**	**$3,263,088**	**$2,801,430**	**$3,207,076**
%Change (year over year)			11.2%	-14.1%	14.5%
	2020	**2021**	**2022**		
Operations	$785,741	$815,322	$901,091		
Maintenance	$501,236	$562,975	$576,747		
Subtotal	**$1,286,976**	**$1,378,298**	**$1,477,837**		
%Change (year over year)	11.1%	7.1%	7.2%		
%Change (Test Year vs Last Rebasing Year - Actual)		14.6%	22.9%		
Billing and Collecting	$837,380	$951,322	$962,860		
Community Relations	$30,338	$41,362	$42,318		
Administrative and General+LEAP	$1,203,797	$1,158,155	$1,225,378		
Subtotal	**$2,071,515**	**$2,150,839**	**$2,230,557**		
%Change (year over year)	1.1%	3.8%	3.7%		
%Change (Test Year vs Last Rebasing Year - Actual)		15.5%	19.8%		
Total	**$3,358,492**	**$3,529,137**	**$3,708,394**		
%Change (year over year)	4.7%	5.1%	5.1%		

The overall costs have remained relatively steady since the last cost of service in 2016. The trend fluctuated in 2017, 2018 and readjusted in 2019. This can be attributed to an increase in capital work in 2018. As noted in the continuity schedule, the inverse trend can be observed for capital costs as capital additions observed an increase of $253,773 in 2018 compared to 2017 and subsequently decreased by $219,500 in 2019 compared to 2018 (excluding capital spend related to the ICM). This increase in 2018 compared to other years is due to additional capital transformer work in 2018 to convert the voltage of transformers.

Billing and Collecting shows an increase of $230K from the last board approved Cost of Service. The increase can be attributed to inflationary increases as well as increased costs associated with various elements of billing and collecting such as software, outside services, paper, stamps, and salaries.

ORPC is of the opinion that there is a minimum cost required to operate any utility and as a small rural utility, its proposed OM&A reflects the minimum required costs. That said, ORPC will continue to seek savings and efficiencies to minimize costs increases for its customers. The proposed OM&A expenses for 2021 -2022 are in line with what ORPC expects regular yearly OM&A costs will be going forward.

Specifics regarding year over year variances are presented in Section 4.2.2 of this Exhibit, and a comparison to an inflationary increase is presented at Section 4.3.2.

Inflation Rate and Assumptions

The CPI rate is a measure that can fluctuate significantly from quarter to quarter and year over year. The average inflation rate for 2016-2020 as published by the Bank of Canada is 1.84%. Using the most recent rate does not always reflect the historical trends nor predicted trends; therefore ORPC typically uses the flat rate of 2% of inflation for budgeting purposes.

Other Assumptions

All Outside, Office and Technical employees are unionized and adjusted yearly based on a Collective Agreement. Management and non-union employees are either adjusted yearly based on the inflation factor included the Collective Agreement for Outside, Office and Technical employees or is adjusted based on progression and performance on a yearly basis. The utility does not expect any significant changes in its business environment (ref: Business Plan) and expects no material growth going forward (ref: Exhibit 3). The utility does not expect to hire any additional employees in the 2022 -2026 period and proposes to keep the same corporate structure going forward.

ORPC notes that at this time, it capitalizes labour burdens but it does not capitalize any administrative burdens for items other than labour. Therefore, there were no increases in OM&A because of the MIFRS policy. Appendix 2-D Overhead Expenses is not presented as a result.

OEB Appendix 2-JA below shows a summary of ORPC Operations, Maintenance and Administrative ("OM&A") costs as required by the OEB's filing guidelines.

Table 3 – OEB Appendix 2-JA – Summary of Recoverable OM&A Expenses

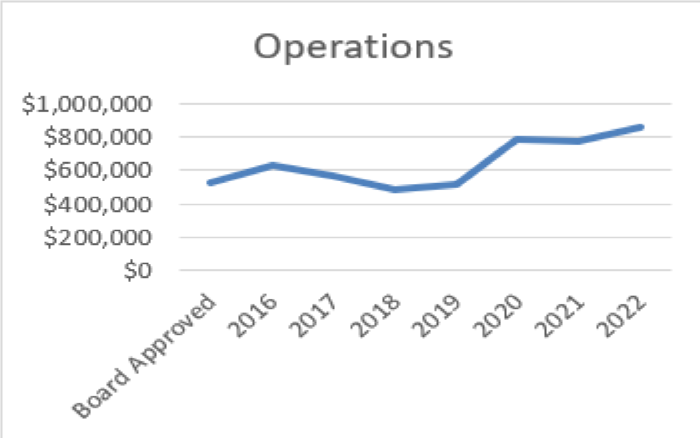
	Board Approved	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Operations	$529,246	$630,729	$565,513	$484,252	$513,327	$785,741	$815,322	$901,091
Maintenance	$673,343	$613,081	$692,292	$500,384	$645,567	$501,236	$562,975	$576,747
SubTotal	**$1,202,589**	**$1,243,810**	**$1,257,805**	**$984,636**	**$1,158,895**	**$1,286,976**	**$1,378,298**	**$1,477,837**
%Change (year over year)		3.4%	1.1%	-21.7%	17.7%	11.1%	7.1%	7.2%
%Change (Test Year vs Last Rebasing Year - Actual)							14.6%	22.9%
Billing and Collecting	$733,000	$747,071	$804,067	$668,041	$748,224	$837,380	$951,322	$962,860
Community Relations	$67,000	$55,936	$79,674	$71,838	$64,147	$30,338	$41,362	$42,318
Administrative and General+LEAP	$1,062,375	$886,993	$1,121,542	$1,076,915	$1,235,810	$1,203,797	$1,158,155	$1,225,378
SubTotal	**$1,862,375**	**$1,690,000**	**$2,005,283**	**$1,816,794**	**$2,048,181**	**$2,071,515**	**$2,150,839**	**$2,230,557**

%Change (year over year)		-44.9%	18.7%	-9.4%	12.7%	1.1%	3.8%	3.7%
%Change (Test Year vs Last Rebasing Year - Actual)							15.5%	19.8%
Total	**$3,064,964**	**$2,933,810**	**$3,263,088**	**$2,801,430**	**$3,207,076**	**$3,358,492**	**$3,529,137**	**$3,708,394**
%Change (year over year)			11.2%	-14.1%	14.5%	4.7%	5.1%	5.1%

Table 4 – Year over Year Variances

2% inflationary increase	**Board Approved**	**BA-16**	**16-17**	**17-18**	**18-19**	**19-20**	**20-21**	**21-22**
Operations	$529,246	$101,483	-$65,216	-$81,261	$29,075	$272,413	$29,582	$85,768
Maintenance	$673,343	-$60,262	$79,212	-$191,909	$145,184	-$144,331	$61,740	$13,771
Billing and Collecting	$733,000	$14,071	$56,996	-$136,026	$80,183	$89,156	$113,943	$11,538
Community Relations	$67,000	-$11,064	$23,738	-$7,836	-$7,691	-$33,809	$11,024	$957
Administrative and General	$1,062,375	-$175,382	$234,549	-$44,627	$158,895	-$32,012	-$45,642	$67,223
Total	**$3,064,964**	**-$131,154**	**$329,278**	**-$461,658**	**$405,645**	**$151,416**	**$170,646**	**$179,257**

**ORPC notes that it has modified appendix 2-JA so that it would fit on this page.*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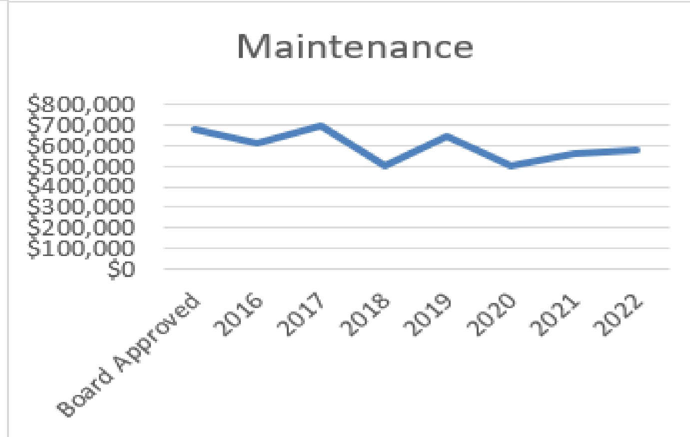
Board Approved
2016
2017
2018
2019
2020
2021
2022


Maintenance
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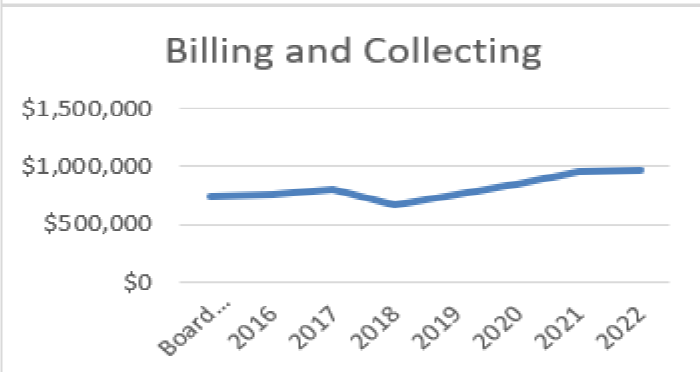
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$0
Board Approved
2016
2017
2018
2019
2020
2021
2022


Billing and Collecting
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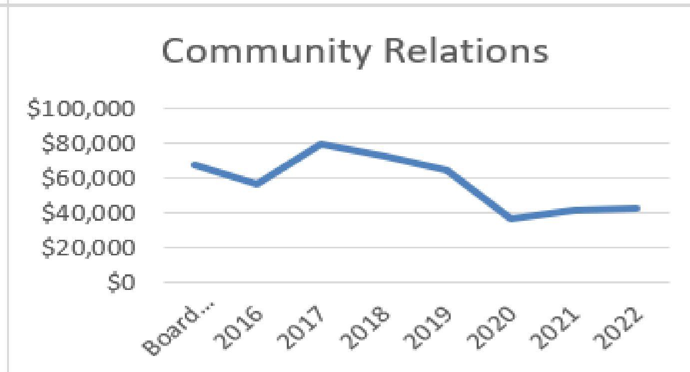
$1,000,000
$500,000
$0
Board...
2016
2017
2018
2019
2020
2021
2022


Community Relations
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$80,000
$60,000
$40,000
$20,000
$0
Board...
2016
2017
2018
2019
2020
2021
2022

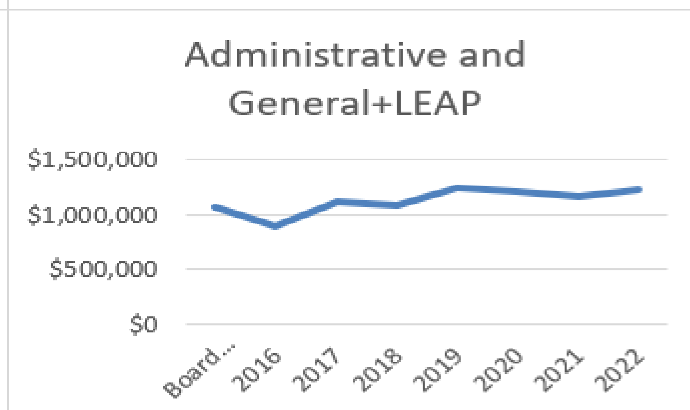

Administrative and General+LEAP
$1,500,000
$1,000,000
$500,000
$0
Board...
2016
2017
2018
2019
2020
2021
2022

Table 5 – Detailed OM&A Year over Year Spending

Description	2016	2017	2018	2019	2020	2021	2022
Operations							
5005-Operation Supervision and Engineering	$93,912	$126,977	$109,143	$96,866	$84,627	$151,203	$251,800
5010-Load Dispatching	$6,910	$13,989	$14,423	$5,418	$5,518	$5,954	$3,331
5012-Station Buildings and Fixtures Expense	$163,817	$127,811	$111,486	$66,001	$80,415	$103,954	$108,616
5014-Transformer Station Equipment - Operation Labour	$0	$0	$0	$0	$0	$0	$0
5015-Transformer Station Equipment - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0
5016-Distribution Station Equipment - Operation Labour	$0	$0	$22	$114	$12,775	$20,946	$21,501
5017-Distribution Station Equipment - Operation Supplies and Expenses	$120	$9,390	$9,390	$8,203	$8,262	$9,000	$9,600
5020-Overhead Distribution Lines and Feeders - Operation Labour	$0	$0	$3,295	$1,490	$36,185	$16,752	$17,195
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$1,588	$5,936	$2,183	$993	$0	$3,500	$3,500
5030-Overhead Sub transmission Feeders - Operation	$0	$0	$585	$0	$0	$18,079	$18,558
5035-Overhead Distribution Transformers- Operation	$0	$0	$0	$105	$6,121	$8,784	$9,016
5040-Underground Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$6,529	$0	$0
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0
5050-Underground Sub transmission Feeders - Operation	$0	$0	$0	$0	$0	$0	$0
5055-Underground Distribution Transformers - Operation	$0	$0	$0	$50	$868	$8,784	$8,557
5060-Street Lighting and Signal System Expense	$0	$0	$0	$0	$0	$0	$0
5065-Meter Expense	$179,239	$110,726	$113,461	$143,924	$82,585	$67,521	$69,062
5070-Customer Premises - Operation Labour	$89,677	$89,330	$76,365	$94,926	$113,772	$29,183	$29,956
5075-Customer Premises - Materials and Expenses	$1,291	$0	$0	$485	$2,799	$8,780	$9,370
5085-Miscellaneous Distribution Expense	$94,175	$81,355	$43,899	$93,653	$301,419	$318,160	$295,739
5090-Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5095-Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$37,264	$37,823	$38,391
5096-Other Rent	$0	$0	$0	$1,100	$6,600	$6,900	$6,900
Total - Operations	$630,729	$565,513	$484,252	$513,327	$785,741	$815,322	$901,091
Maintenance							
5105-Maintenance Supervision and Engineering	$1,511	$2,200	$2,400	$2,600	$48,718	$64,401	$66,106
5110-Maintenance of Buildings and Fixtures - Distribution Stations	$28,643	$68,063	$26,172	$8,566	$15,363	$67,128	$68,745
5112-Maintenance of Transformer Station Equipment	$0	$0	$0	$0	$0	$0	$0

5114-Maintenance of Distribution Station Equipment	$120,691	$98,650	$139,983	$104,681	$33,342	$76,591	$78,618
5120-Maintenance of Poles, Towers and Fixtures	$33,929	$27,080	$6,383	$4,649	$6,055	$17,002	$17,445
5125-Maintenance of Overhead Conductors and Devices	$186,641	$182,571	-$63,503	$135,077	$72,997	$43,963	$45,047
5130-Maintenance of Overhead Services	$40,093	$71,901	$82,284	$74,833	$50,155	$46,446	$47,635
5135-Overhead Distribution Lines and Feeders - Right of Way	$95,594	$145,052	$168,160	$217,305	$100,547	$152,456	$156,226
5145-Maintenance of Underground Conduit	$0	$0	$0	$0	$1,368	$8,872	$9,075
5150-Maintenance of Underground Conductors and Devices	$19,180	$12,579	$8,922	$11,377	$11,113	$11,899	$12,182
5155-Maintenance of Underground Services	$15,135	$14,698	$19,716	$23,295	$11,438	$17,552	$17,995
5160-Maintenance of Line Transformers	$71,665	$69,500	$108,040	$61,739	$144,059	$42,101	$42,686
5165-Maintenance of Street Lighting and Signal Systems	$0	$0	$0	$0	$0	$0	$0
5170-Sentinel Lights - Labour	$0	$0	$0	$0	$0	$0	$0
5172-Sentinel Lights - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0
5175-Maintenance of Meters	$0	$0	$1,828	$1,446	$6,081	$14,564	$14,986
5178-Customer Installations Expenses- Leased Property	$0	$0	$0	$0	$0	$0	$0
5185-Water Heater Rentals - Labour	$0	$0	$0	$0	$0	$0	$0
5186-Water Heater Rentals - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0
5190-Water Heater Controls - Labour	$0	$0	$0	$0	$0	$0	$0
5192-Water Heater Controls - Materials and Expenses	$0	$0	$0	$0	$0	$0	$0
5195-Maintenance of Other Installations on Customer Premises	$0	$0	$0	$0	$0	$0	$0
Total - Maintenance	$613,081	$692,292	$500,384	$645,567	$501,236	$562,975	$576,747
Billing and Collecting							
5305-Supervision	$0	$0	$0	$0	$0	$59,554	$61,129
5310-Meter Reading Expense	$37,384	$45,233	$51,381	$52,758	$55,013	$58,033	$61,176
5315-Customer Billing	$407,932	$439,204	$427,057	$441,086	$588,954	$609,758	$611,929
5320-Collecting	$181,131	$146,022	$155,218	$160,341	$142,898	$123,898	$127,047
5325-Collecting- Cash Over and Short	$0	$0	$0	-$10	-$1,121	$0	$0
5330-Collection Charges	$0	$0	$0	-$10,775	-$6,180	$0	$0
5335-Bad Debt Expense	$120,624	$173,608	$34,385	$105,151	$57,859	$100,000	$101,500
5340-Miscellaneous Customer Accounts Expenses	$0	$0	$0	-$327	-$43	$80	$80
Total - Billing and Collecting	$747,071	$804,067	$668,041	$748,224	$837,380	$951,322	$962,860
Community Relations							
5405-Supervision	$0	$0	$0	$0	$431	$0	$0

5410-Community Relations - Sundry	$18,085	$30,308	$32,391	$28,368	$28,496	$13,010	$13,337
5415-Energy Conservation	$0	$0	$0	$0	$0	$0	$0
5420-Community Safety Program	$37,851	$49,116	$39,187	$35,779	$1,411	$28,352	$28,982
5425-Miscellaneous Customer Service and Informational Expenses	$0	$0	$0	$0	$0	$0	$0
5505-Supervision	$0	$0	$0	$0	$0	$0	$0
5510-Demonstrating and Selling Expense	$0	$0	$0	$0	$0	$0	$0
5515-Advertising Expense	$0	$250	$260	$0	$0	$0	$0
5520-Miscellaneous Sales Expense	$0	$0	$0	$0	$0	$0	$0
Total - Community Relations	$55,936	$79,674	$71,838	$64,147	$30,338	$41,362	$42,318
Administrative and General Expenses							
5605-Executive Salaries and Expenses	$43,331	$45,693	$47,173	$48,403	$39,963	$44,930	$46,047
5610-Management Salaries and Expenses	$190,009	$173,557	$246,574	$287,264	$341,442	$418,038	$418,242
5615-General Administrative Salaries and Expenses	$225,293	$381,185	$251,391	$248,143	$88,322	$34,284	$35,126
5620-Office Supplies and Expenses	$79,632	$87,830	$77,019	$86,445	$79,315	$81,814	$81,814
5625-Administrative Expense Transferred/Credit	$0	$0	$0	$0	$0	$0	$0
5630-Outside Services Employed	$38,972	$71,698	$71,469	$20,380	$17,343	$32,392	$32,452
5635-Property Insurance	$0	$13,866	$12,438	$9,656	$12,740	$12,750	$13,000
5640-Injuries and Damages	$0	$0	$0	$0	$0	$0	$0
5645-Employee Pensions and Benefits	$0	$0	$29,565	$22,764	$166,786	$170,121	$173,524
5650-Franchise Requirements	$0	$0	$0	$0	$0	$0	$0
5655-Regulatory Expenses	$118,819	$129,256	$130,504	$173,232	$159,828	$117,730	$183,062
5660-General Advertising Expenses	$0	$0	$0	$0	$0	$0	$0
5665-Miscellaneous General Expenses	$67,550	$79,434	$78,325	$80,658	$78,859	$79,000	$81,500
5670-Rent	$13,200	$15,000	$15,000	$15,000	$14,331	$12,000	$12,000
5675-Maintenance of General Plant	$97,607	$111,322	$104,479	$231,262	$191,538	$128,180	$132,811
5680-Electrical Safety Authority Fees	$8,981	$7,501	$7,776	$7,405	$8,612	$8,000	$8,300
5681-Special Purpose Charge Expense	$0	$0	$0	$0	$0	$0	$0
5685-Independent Market Operator Fees and Penalties	$0	$0	$0	$0	$0	$0	$0
5695-OM&A Contra	$0	$0	$0	$0	$0	$0	$0
6205-Donations	$48	$48	$48	$110	$6,325	$110	$110
6205-Sub-account LEAP Funding	$3,600	$5,200	$5,201	$5,200	$4,720	$18,916	$7,500
6210-Life Insurance	$0	$0	$0	$0	$0	$0	$0
6215-Penalties	$0	$0	$0	$0	$0	$0	$0
6225-Other Deductions	$0	$0	$0	$0	$0	$0	$0

6305-Extraordinary Income	$0	$0	$0	$0	$0	$0	$0
6310-Extraordinary Deductions	$0	$0	$0	$0	$0	$0	$0
6315-Income Taxes: Extraordinary Item	$0	$0	$0	$0	$0	$0	$0
6405-Discontinued Operations - Income/ Gains	$0	$0	$0	$0	$0	$0	$0
6410-Discontinued Operations - Deductions/ Losses	$0	$0	$0	$0	$0	$0	$0
6415-Income Taxes, Discontinued Operations	$0	$0	$0	$0	$0	$0	$0
Total - Administrative and General Expenses	$886,993	$1,121,542	$1,076,915	$1,235,810	$1,203,797	$1,158,155	$1,225,378
Total OM&A	$2,933,810	$3,263,088	$2,801,430	$3,207,076	$3,358,492	$3,529,137	$3,708,394

4.2 SUMMARY & COST DRIVER TABLES

4.2.1 SUMMARY OF COST DRIVERS

In accordance with the OEB's minimum filing requirements, OEB Appendix 2-JB, OM&A Cost Drivers, presented below outlines the key drivers of OM&A costs over the period of 2015 to 2021. The highlighted items represent the items that meet the materiality threshold and require further explanation. An overview of the reasons behind the costs drivers is presented following the table, and detailed explanations are presented in Section 4.2.2-Year over Year Variance Analysis.

Table 6 – OEB Appendix 2-JB – Recoverable OM&A Cost Driver Table

Description	**17-16**	**18-17**	**19-18**	**20-19**	**21-20**	**22-21**
Operations						
5005-Operation Supervision and Engineering	33,065.11	(17,834.14)	(12,277.52)	(12,238.40)	66,575.39	100,596.83
5010-Load Dispatching	7,078.18	434.32	(9,005.39)	100.94	435.26	(2,622.44)
5012-Station Buildings and Fixtures Expense	(36,006.49)	(16,324.48)	(45,485.15)	14,414.34	23,538.88	4,661.78
5016-Distribution Station Equipment - Operation Labour	0.00	22.11	91.66	12,660.92	8,171.70	554.22
5017-Distribution Station Equipment - Operation Supplies and Expenses	9,270.00	0.00	(1,186.68)	59.13	737.55	600.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	0.00	3,295.00	(1,804.75)	34,694.99	(19,433.51)	443.34
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	4,348.45	(3,752.86)	(1,190.01)	(993.31)	3,500.00	0.00
5030-Overhead Sub transmission Feeders - Operation	0.00	584.97	(584.97)	0.00	18,079.13	478.47
5035-Overhead Distribution Transformers- Operation	0.00	0.00	105.20	6,015.50	2,663.00	232.39
5040-Underground Distribution Lines and Feeders - Operation Labour	0.00	0.00	0.00	6,529.44	(6,529.44)	0.00
5055-Underground Distribution Transformers - Operation	0.00	0.00	49.85	818.30	7,915.55	(227.06)
5065-Meter Expense	(68,512.95)	2,735.05	30,462.73	(61,338.41)	(15,064.62)	1,541.41
5070-Customer Premises - Operation Labour	(347.56)	(12,964.59)	18,561.14	18,846.01	(84,588.88)	772.42
5075-Customer Premises - Materials and Expenses	(1,291.14)	0.00	484.79	2,313.80	5,981.41	590.00
5085-Miscellaneous Distribution Expense	(12,819.72)	(37,456.31)	49,754.27	207,765.76	16,741.46	(22,420.63)
5095-Overhead Distribution Lines and Feeders - Rental Paid	0.00	0.00	0.00	37,264.31	558.96	567.35
5096-Other Rent	0.00	0.00	1,100.00	5,500.00	300.00	0.00
Total - Operations	(65,216.12)	(81,260.93)	29,075.17	272,413.32	29,581.84	85,768.08
Maintenance						
5105-Maintenance Supervision and Engineering	688.77	200.00	199.62	46,118.13	15,683.62	1,704.88
5110-Maintenance of Buildings and Fixtures - Distribution Stations	39,419.73	(41,891.00)	(17,605.41)	6,797.02	51,764.35	1,617.02
5114-Maintenance of Distribution Station Equipment	(22,040.70)	41,333.40	(35,301.90)	(71,339.52)	43,249.13	2,026.70
5120-Maintenance of Poles, Towers and Fixtures	(6,849.06)	(20,697.02)	(1,733.66)	1,406.25	10,946.61	443.34
5125-Maintenance of Overhead Conductors and Devices	(4,070.33)	(246,073.74)	198,579.77	(62,080.13)	(29,033.06)	1,084.01
5130-Maintenance of Overhead Services	31,807.60	10,383.48	(7,451.38)	(24,677.65)	(3,709.35)	1,189.39
5135-Overhead Distribution Lines and Feeders - Right of Way	49,458.21	23,107.77	49,145.49	(116,757.88)	51,909.02	3,769.69
5145-Maintenance of Underground Conduit	0.00	0.00	0.00	1,367.94	7,504.42	203.00
5150-Maintenance of Underground Conductors and Devices	(6,601.06)	(3,656.53)	2,454.77	(264.43)	786.16	283.15
5155-Maintenance of Underground Services	(436.63)	5,017.59	3,579.05	(11,856.66)	6,113.77	443.34
5160-Maintenance of Line Transformers	(2,164.74)	38,539.56	(46,300.93)	82,320.18	(101,957.94)	584.81
5175-Maintenance of Meters	0.00	1,827.60	(381.74)	4,635.30	8,482.99	422.13
Total - Maintenance	79,211.79	(191,908.89)	145,183.68	(144,331.45)	61,739.72	13,771.46

Billing and collecting						
5305-Supervision	0.00	0.00	0.00	0.00	59,554.17	1,574.42
5310-Meter Reading Expense	7,848.86	6,148.47	1,377.03	2,254.60	3,019.63	3,143.84
5315-Customer Billing	31,272.06	(12,146.96)	14,029.33	147,868.06	20,803.43	2,170.82
5320-Collecting	(35,109.49)	9,196.04	5,122.67	(17,443.07)	(18,999.56)	3,148.78
5325-Collecting- Cash Over and Short	0.00	0.00	(10.10)	(1,110.98)	1,121.08	0.00
5330-Collection Charges	0.00	0.00	(10,775.00)	4,595.00	6,180.00	0.00
5335-Bad Debt Expense	52,984.41	(139,223.51)	70,766.19	(47,291.75)	42,140.87	1,500.00
5340-Miscellaneous Customer Accounts Expenses	0.00	0.00	(326.79)	283.88	122.91	0.00
Total - Billing and Collecting	56,995.84	(136,025.96)	80,183.33	89,155.74	113,942.53	11,537.86
	0.00	0.00	0.00	0.00	59,554.17	1,574.42
Community Relations						
5405-Supervision	0.00	0.00	0.00	430.70	(430.70)	0.00
5410-Community Relations - Sundry	12,223.67	2,082.84	(4,023.47)	127.93	(15,485.98)	327.11
5420-Community Safety Program	11,264.81	(9,928.60)	(3,408.24)	(34,367.75)	26,940.40	629.77
5515-Advertising Expense	249.50	10.00	(259.50)	0.00	0.00	0.00
Total - Community Relations	23,737.98	(7,835.76)	(7,691.21)	(33,809.12)	11,023.72	956.88
Administrative and General Expenses						
5605-Executive Salaries and Expenses	2,362.27	1,479.84	1,229.42	(8,439.10)	4,966.34	1,117.59
5610-Management Salaries and Expenses	(16,451.95)	73,017.22	40,689.71	54,178.23	76,596.44	203.76
5615-General Administrative Salaries and Expenses	155,891.53	(129,793.14)	(3,248.54)	(159,820.99)	(54,037.80)	842.26
5620-Office Supplies and Expenses	8,197.92	(10,810.74)	9,425.90	(7,130.21)	2,499.46	0.00
5630-Outside Services Employed	32,726.13	(229.70)	(51,088.20)	(3,037.27)	15,048.79	60.00
5635-Property Insurance	13,865.90	(1,427.89)	(2,782.49)	3,084.22	10.26	250.00
5645-Employee Pensions and Benefits	0.00	29,564.83	(6,801.23)	144,021.90	3,335.71	3,402.42
5655-Regulatory Expenses	10,436.94	1,248.07	42,727.32	(13,404.09)	(42,098.05)	65,332.36
5665-Miscellaneous General Expenses	11,884.36	(1,109.17)	2,333.01	(1,799.59)	141.39	2,500.00
5670-Rent	1,800.00	0.00	0.00	(669.24)	(2,330.76)	0.00
5675-Maintenance of General Plant	13,715.58	(6,842.87)	126,782.63	(39,723.87)	(63,357.69)	4,630.26
5680-Electrical Safety Authority Fees	(1,480.07)	275.97	(371.97)	1,207.48	(612.00)	300.00
6205-Donations	0.00	0.00	62.00	6,215.00	(6,215.00)	0.00
6205-Sub-account LEAP Funding	1,600.00	1.00	(1.04)	(479.96)	14,196.00	(11,416.00)
Total - Administrative and General Expenses	234,548.61	(44,626.58)	158,956.52	(25,797.49)	(51,856.91)	67,222.65

OPERATIONS

5005-Operation Supervision and Engineering

2020 – 2021: Increase of $66,575

A position was vacant for parts of 2019 and 2020. The position was filled part way through 2020. A portion of this employee's time including burdens is included in the 2021 combined actuals and forecast. The previous employee split their time between 5315 and 5615 until part way through 2019.

2021 – 2022: Increase of $100,597

Ottawa River Power Corporation has had a vacant position since part way into 2020. Due to the pandemic and hiring difficulties, the position remains vacant. The position is intended to be filled in 2022 which has resulted in an increase in 2022. The increase includes the salary and burdens.

5065-Meter Expense

2016 – 2017: Decrease of $68,513

The figure in 2016 included $79,340 of disposed smart meter O&M costs per the 2016 Cost of Service. This figure was not included in 2017.

2019 – 2020: Decrease of $61,338

In 2019, ORPC reviewed items historically capitalized to the meter accounts and time allocations. The utility determined that more of the meter technician's time required capitalization. Therefore, the decrease in O&M is reflected by an increase in capital meter expenditures.

5070-Customer Premises – Operation Labour

2020 – 2021: Decrease of $84,589

Employee labour in this category was spread between categories 5012, 5016, 5030 and 5085 in 2021 compared to the coding in 2020 as ORPC further re-aligns some of its coding. The sum of the increase in these categories total $66,531 which is consistent with the decrease in 5070 in 2021.

5085-Miscellaneous Distribution Expense

2019 – 2020: Increase of $207,765

On January 1, 2020, ORPC implemented new O&M sub-accounts to ensure that its accounts were aligned with the USofA. This resulted in training, personal protective equipment, inventory maintenance, standby, waste management and storage among other expenditures being included in 5085. Specifically, this resulted in personal protective equipment of $30,842, inventory maintenance of $34,286.39 and $129,738.73 of standby labour now included in 5085. These expenditures were previously included in 5125.

MAINTENANCE

5110-Maintenance of Buildings and Fixtures

2020 – 2021: Increase of $51,764

The increase is a result of a difference in time allocation for an employee between categories 5110 and 5675. The variances between the two categories offset.

5114-Maintenance of Distribution Station Equipment

2019 – 2020: Decrease of $71,340

ORPC employs an employee who performs the maintenance of distribution station equipment. Part way through 2019, this employee departed on sick leave and 2020 was the first full year of this sick leave.

5125-Maintenance of Overhead Conductors and Devices

2017 – 2018: Decrease of $246,074

In 2017, vehicle depreciation of $161,599 was included in grouping 5125 whereas it was included in 5705 in 2018. Additionally, vehicle maintenance costs of $30,653 were included in 5125 in 2017 which were included in 5675 in 2018. Finally, this grouping also captured inventory adjustments, burdens and losses which vary with the amount of capital work performed. The total of these decreased by $64,935 in 2018 as a result of the elimination of a 10% on materials.

2018 – 2019: Increase of $198,580

This grouping included $152,794 of net vehicle repairs and maintenance burden credits in 2018 which were included in grouping 5675 in 2019. 2019 included a net burden debit of $79,545. This large swing was caused by an increase in capital projects in 2018 which significantly increased the amount of vehicle time allocated to capital.

2019 – 2020: Decrease of $62,080

The decrease in 2020 was caused by the pandemic. Work at the beginning of the pandemic was limited to emergency responses only which limited regular planned repairs and maintenance on overhead conductors and devices.

5135-Overhead Distribution Lines and Feeders - Right of Way

2019 – 2020: Decrease of $116,758

The decrease in 2020 was caused by the pandemic and completion of construction on the new substation in Almonte. Work at the beginning of the pandemic was limited to emergency responses only which limited regular planned repairs and maintenance on overhead conductors and devices. The construction of the pole line to the new substation in Almonte reallocated ORPC's staffing resources to the ICM project.

2020 – 2021: Increase of $51,909

2021 actuals and projections forecast that regular maintenance programs will take place resulting in an increase.

5160-Maintenance of Line Transformers

2019 – 2020: Increase of $82,320

Increase of $78,183 in labour on line transformer maintenance due to requirement to test transformers for PCBs by obtaining and testing oil samples.

2020 – 2021: Decrease of $101,958

Decrease in 2021 due to expected normalization of expenditures after significant labour in 2020 to complete most PCB testing.

BILLING AND COLLECTING

5305-Supervision

2020 – 2021: Increase of $59,554

A portion of the salary for the Office Manager, who is in charge of supervising billing activities, was previously included in administrative and general expenses in 2020 but was reallocated to 5315 in 2020 and then moved to 5305 in 2021.

5315-Customer Billing

2019 – 2020: Increase of $147,868

Increase related to an increase in customer billing labour. The Office Manager previously included a portion of their salary in administrative and general expenditures. This salary was included in 5315 in 2020 due to ORPC re-aligning its groupings and expenditures. Additionally, ORPC experienced 2 billing clerk retirements which necessitated training for new billings clerks. ORPC also allocated heat and hydro expenditures to account 5315 which were previously allocated entirely between 5012, 5114 and 5675.

5335-Bad Debt Expenses

2016 – 2017: Increase of $52,984

ORPC performs write offs for uncollectable accounts at the end of each year. These writes offs in 2017 included some large business write offs due to bankruptcies for individual amounts as high as $12,554 and $8,308 each.

2017 – 2018: Decrease of $139,224

Total write offs in 2017 amounts to $190,989 compared to $90,659 in 2018 representing a decrease of $100,330. The remaining decrease can be attributed to a decrease of $31,343 in the allowance for doubtful accounts. The allowance was decreased after a decrease in arrears following the end of the first moratorium in 2017 and following the large write offs in 2017.

2018 – 2019: Increase of $70,766

There was an increase in bad debts in 2019 primarily due to 2 uncollectible invoices for $28,434 and $22,587 respectively. These invoices were related to uncollectible ORPC destruction of asset insurance claims.

ADMINISTRATION

5610-Management Salaries and Expenses

2017 – 2018: Increase of $73,017

The CFO position was filled part-way through 2017. The following year 2018 would represent the first full year with the position occupied resulting in increased management salaries and expenses.

2019 – 2020: Increase of $54,178

Management salaries and expenses previously only included the hourly rate multiplied by the time assigned. In 2020, ORPC modified its calculation to include labour burdens of 44.23% to account for CPP, EI, EHT, WSIB, benefits and other expenditures in the assignment of costs. The previous burdens on management salaries were included in 5645.

2020 – 2021: Increase of $76,596

The 2021 budgeted salary for a general administration employee was included in 5610 for 2021 whereas it was previously grouped with 5615 resulting in an increase for 2021.

5615-General Administrative Salaries and Expenses

2016 – 2017: Increase of $155,892

In 2017, there was a cost of $137,132 that was included in 5615 relating to an employee departure. Remaining increase can be attributed to annual rate increases per the collective agreement.

2017 – 2018: Decrease of $129,793

As noted, there was a cost included in 5615 in 2017 of $137,132 relating to an employee departure. There was no such cost in 2018 resulting in a decrease.

2019 – 2020: Decrease of $159,821

In 2020, ORPC re-aligned its accounts and coding. This result in a decrease in general administration labour of $131,898 as labour was allocated to appropriate groupings based on the activity performed. Additionally, there was a parental leave which resulted in a vacant general administration position for 10 months of 2020.

2020 – 2021: Decrease of $54,038

The 2021 budgeted salary for a general administration employee was included in 5610 for 2021 whereas it was previously grouped with 5615 resulting in a projected decrease for 2021.

5630-Outside Services Employed

2018 – 2019: Decrease of $51,088

Decrease of $46,678 relating to legal fees in 2018 for 2 employee departures.

5645-Employee Pension and Benefits

2019 – 2020: Increase of $144,022

In July 2019, ORPC decreased the percentage of its payroll burden. As a result, less payroll expenses were allocated through the remaining categories and remained in 5645.

5655-Regulatory Expenses

2021 – 2022: Increase of $65,332

The amortization of the 2016 Cost of Service ended on April 30, 2021. From May 1, 2021 to April 30, 2022, there is no amortization expense included. The costs for the applications for rates effective May 1, 2022 is expected to commence on the same date. Additionally, the expenses for the current application are expected to increase the annual amortization by $22,626 compared to the 2016 application.

5675-Maintenace of General Plant

2018 – 2019: Increase of $126,783

In 2019, vehicle expenses of $79,545 were included in grouping 5675 whereas vehicle expenses were included in 5125 in 2018.

2020 – 2021: Decrease of $63,358

The increase is a result of a difference in allocation for a maintenance employee between categories 5110 and 5675. The variances between the two categories offset.

4.2.2 YEAR OVER YEAR VARIANCE ANALYSIS

The following section provides explanations of the year over year cost variances and drivers. As with the previous section, the utility explains variances above the materiality threshold of $50,000. For each significant change ORPC has described the reasons and decision that was made to manage the cost increase or decrease.

Table 7 – 2016 Actual vs. 2016 Board Approved to

Table 13 – 2022 Test vs. 2021 Bridge below show the year over year variances of OM&A expenses for 2016 Board Approved to the 2022 Test Year. An overview of significant variances are explaind below each table.

Table 7 – 2016 Actual vs. 2016 Board Approved

	Board Approved	2016	$ Var	% Var
Operations	$529,246	$630,729	$101,483	19.18%
Maintenance	$673,343	$613,081	-$60,262	-8.95%
Billing and Collecting	$733,000	$747,071	$14,071	1.92%
Community Relations	$67,000	$55,936	-$11,064	-16.51%
Administrative and General	$1,062,375	$886,993	-$175,382	-16.51%
Total	**$3,064,964**	**$2,933,810**	**-$131,154**	**-4.28%**

The total OM&A expenses in 2016 were $131,154 lower than 2016 Actual. The difference in Administrative and General was as a result of an employee departure and multiple retirements that resulted in a vacancy in the President & CEO position and subsequently a vacancy in the CFO position. The differences in Operations and Maintenance were primarily caused by reallocations of expenditures between the two categories.

Table 8 - 2017 Actual vs. 2016 Actual

	2016	2017	$ Var	% Var
Operations	$630,729	$565,513	-$65,216	-10.34%
Maintenance	$613,081	$692,292	$79,212	12.92%
Billing and Collecting	$747,071	$804,067	$56,996	7.63%
Community Relations	$55,936	$79,674	$23,738	42.44%
Administrative and General	$886,993	$1,121,542	$234,549	26.44%
Total	**$2,933,810**	**$3,263,088**	**$329,278**	**11.22%**

The total OM&A expenses in 2017 were $329,278 greater than 2016 Actual. Operations costs decreased with the inclusion of $79,340 of disposed smart meter O&M costs in 2016 per the 2016 Cost of Service. Maintenance costs increased mainly as a result of increased tree trimming activities. The level of tree trimming varies year to year depending on the location of the tree trimming cycle. For Billing and Collecting, writes offs in 2017 included some large business write offs due to bankruptcies for individual amounts as high as $12,554 and $8,308 each. In 2017 Administrative and General Expenditures, there was a cost of $137,132 that was included relating to an employee departure. Remaining increase in Administrative and General can be attributed to annual rate increases per the collective agreement.

Table 9 - 2018 Actual vs. 2017 Actual

	2017	2018	$ Var	% Var
Operations	$565,513	$484,252	-$81,261	-14.37%
Maintenance	$692,292	$500,384	-$191,909	-27.72%
Billing and Collecting	$804,067	$668,041	-$136,026	-16.92%
Community Relations	$79,674	$71,838	-$7,836	-9.83%
Administrative and General	$1,121,542	$1,076,915	-$44,627	-3.98%
Total	**$3,263,088**	**$2,801,430**	**-$461,658**	**-14.15%**

The total OM&A expenses in 2018 were $461,658 less than 2017 Actual. Both operations and maintenance expenditures decreased as a result of additional capital work performed on transformers in 2018 to convert the voltage of transformers. Additionally, vehicle depreciation of $161,599 was included in 2017 Maintenance whereas it was reallocated to depreciation in 2018. In regards to Billing and Collecting, total write offs in 2017 amounted to $190,989 compared to $90,659 in 2018 representing a decrease of $100,330.

Table 10 - 2019 Actual vs. 2018 Actual

	2018	2019	$ Var	% Var
Operations	$484,252	$513,327	$29,075	6.00%
Maintenance	$500,384	$645,567	$145,184	29.01%
Billing and Collecting	$668,041	$748,224	$80,183	12.00%
Community Relations	$71,838	$64,147	-$7,691	-10.71%
Administrative and General	$1,076,915	$1,235,810	$158,895	14.75%
Total	**$2,801,430**	**$3,207,076**	**$405,645**	**14.48%**

The total OM&A expenses in 2019 are $405,645 more than 2018 Actual. Maintenance expenditures included $152,794 of net vehicle repairs and maintenance burden credits in 2018 whereas 2019 included a net burden debit of $79,545. This large swing was caused by an increase in capital projects in 2018 which significantly increased the amount of vehicle time allocated. Billing and Collecting saw an increase in bad debts in 2019 primarily due to 2 uncollectible invoices for $28,434 and $22,587 respectively. These invoices were related to uncollectible ORPC destruction of asset insurance claims. Finally, vehicle expenses of $79,545 were included in Administrative and General in 2019 but were previously included in Maintenance in 2018. Additionally, external auditor costs increased by $27,222 from 2018 to 2019 as a result of a change in external auditors.

Table 11 - 2020 Actual vs. 2019 Actual

	2019	2020	$ Var	% Var
Operations	$513,327	$785,741	$272,413	53.07%
Maintenance	$645,567	$501,236	-$144,331	-22.36%
Billing and Collecting	$748,224	$837,380	$89,156	11.92%
Community Relations	$64,147	$30,338	-$33,809	-52.71%
Administrative and General	$1,235,810	$1,203,797	-$32,012	-2.59%
Total	**$3,207,076**	**$3,358,492**	**$151,416**	**4.72%**

The total OM&A expenses in 2020 were $151,416 greater than 2019 Actual. The increase in Operations is mainly as a result of ORPC implementing new O&M sub-accounts in 2020 to ensure that its accounts were aligned with the USofA. This resulted in training, personal protective equipment, inventory maintenance, standby labour, waste management, pole rental charges and storage among other expenditures being included in Operations. Maintenance costs decreased mainly as a result of the same. These expenditures were mostly previously included in Maintenance but were reallocated to Operations. This was offset by an increase of $82,320 in line transformer maintenance for additional PCB testing required on line transformers. Finally, billing and collecting increased by $89,156 with a portion of the Office Manager now included in Billing and Collecting instead of Administrative of General and as a result of 2 billing clerk retirements which necessitated additional training for new clerks.

Table 12 – 2021 Bridge vs. 2020 Actual

	2020	2021	$ Var	% Var
Operations	$785,741	$815,3221	$29,582	3.76%
Maintenance	$501,236	$562,975	$61,740	12.32%
Billing and Collecting	$837,380	$951,322	$113,943	13.61%
Community Relations	$30,338	$41,362	$11,024	36.34%
Administrative and General	$1,203,797	$1,158,155	-$45,642	-3.79%
Total	**$3,358,492**	**$3,529,137**	**$170,646**	**5.08%**

The total OM&A expenses in 2021 were $170,646 more than 2020 Actual. The increase in Maintenance expenditures is mainly a result of the pandemic affecting regular maintenance programs in 2020 and the actuals and projections for 2021 demonstrating a return to regular maintenance programs. A portion of the salaries for distribution workers were included in Administrative and General in 2020 as a result of the pandemic. Billing and Collecting is expected to increase as a portion of the salary for the Office Manager, who is in charge of supervising billing activities, was previously included in administrative and general expenses in 2020.

Table 13 – 2022 Test vs. 2021 Bridge

	2021	2022	$ Var	% Var
Operations	$815,322	$901,091	$85,768	10.52%
Maintenance	$562,975	$576,747	$13,771	2.45%
Billing and Collecting	$951,322	$962,860	$11,538	1.21%
Community Relations	$41,362	$42,428	$957	2.31%
Administrative and General	$1,158,155	$1,225,378	$67,223	5.80%
Total	**$3,529,137**	**$3,708,394**	**$179,257**	**5.08%**

The total OM&A expenses in 2022 are $179,257 more than 2021 Actual. The increase in Operations is a result of filling vacant Engineering Technician position while the increase in Administrative and General is caused by the increase in amortized Cost of Service costs as 2021 includes 4 months of amortized costs from the 2016 Cost of Service whereas 2022 includes the full year. Additionally, the OEB issued a credit of $11,416 on the quarterly assessments in 2021 that were moved to LEAP funding. 2022 represents a normalized year.

Cost per Customer as per OEB Chapter 2 Appendices

OEB Appendix 2-L Employee Costs at the table below shows an OM&A cost per customer of $319 in 2022 in comparison to $281 in the 2016.

ORPC is also aware that the utility's requirements have increased significantly over the past six years and that the utility employees have been taking on more workload to be able to respond to the increase in these regulatory requirements. The Administration costs per FTE has increased to $82,613 from $64,220.

Cost per Customer as per PEG Benchmarking Calculations

The increase in efficiency from 2019 to 2022 is also reflected ORPC's PEG ranking. ORPC's actual costs (2020) of $6,092,175 is $1,669,903 lower than its Predicted costs of $7,762,078. ORPC has been classified in the 2nd most cost-efficient PEG grouping in 2020 however, with the budgeted Bridge and Test Year forecast, ORPC would be moving to the most efficient group in 2021 and beyond.

Despite being in the most efficient group going forward, ORPC commits to continuing to look for ways of finding efficiencies to help avoid cost increases for its customers when feasible.

Table 14 – PEG Actual vs Predicted Costs

	2019 (Historical)	2020 (Historical)	2021 (Bridge)	2022 (Test Year)	2023	2024
Actual Total Cost	6,003,344	6,092,175	6,174,374	6,490,599	na	na
Predicted Total Cost	7,249,050	7,762,078	8,300,572	8,838,287	na	na
Difference	(1,245,706)	(1,669,903)	(2,126,197)	(2,347,688)	na	na
Percentage Difference (Cost Performance)	**-18.9%**	**-24.2%**	**-29.6%**	**-30.87%**	**na**	**na**
Three-Year Average Performance			-24.6%	-28.63%	na	na
Stretch Factor Cohort						
Annual Result	2	2	1	1	na	na
Three Year Average			2	1	na	na

Table 15 – OEB Appendix 2-L Recoverable OM&A Cost per Customer and FTE

	2016 Board Appr	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Bridge Year	2022 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OM&A Costs								
O&M	$1,202,589	$1,243,810	$1,257,805	$984,636	$1,158,895	$1,286,976	$1,378,298	$1,477,837
Admin Expenses	$1,862,375	$1,690,000	$2,005,283	$1,816,794	$2,048,181	$2,071,515	$2,150,839	$2,230,557
Total Recoverable OM&A from Appendix 2-JB [5]	$3,064,964	$2,933,810	$3,263,088	$2,801,430	$3,207,076	$3,358,492	$3,529,137	$3,708,394
Number of Customers [2,4]	10,923	10,979	11,064	11,209	11,323	11,417	11,526	11,637
Number of FTEs [3,4]	29	26	26	26	26	26	26	27
Customers/FTEs	376.66	422.28	425.55	431.10	435.51	439.10	443.32	431.01
OM&A cost per customer								
O&M per customer	$110	$113	$114	$88	$102	$113	$120	$127
Admin per customer	$171	$154	$181	$162	$181	$181	$187	$192
Total OM&A per customer	$281	$267	$295	$250	$283	$294	$306	$319
OM&A cost per FTE								
O&M per FTE	$41,469	$47,839	$48,377	$37,871	$44,573	$49,499	$53,011	$54,735
Admin per FTE	$64,220	$65,000	$77,126	$69,877	$78,776	$79,674	$82,725	$82,613
Total OM&A per FTE	**$105,688**	**$112,839**	**$125,503**	**$107,747**	**$123,349**	**$129,173**	**$135,736**	**$137,348**

4.2.4 ACTUAL VS INFLATION

Utilities are under constant pressure to relate their spending to cost inflation; therefore, in the preparation of the Test Year budget, ORPC has calculated the year over year inflationary increase in OM&A costs at a rate of 2% and compared to its 2021 proposed OM&A costs.

The table below show ORPC's actual year over year variances vs a hypothetical year over year variance. The inverse variances in Operations and Maintenance is mainly caused by ORPC implementing new O&M sub-accounts to ensure that its accounts were aligned with the USofA. This resulted in expenditures being coded to Operations instead of previously being coded to Maintenance. The Billing and Collecting variance is mainly as a result of a reclassification of the billing supervisor's time out of Administrative and General and into Billing and Collecting.

Table 16 – 2016-2022 Inflationary Increase

	2022 at inflationary increase of 2%	**2022** Projected	**Var from inflationary increase**
Operations	$607,937	$901,091	$293,154
Maintenance	$773,459	$576,747	-$196,712
Billing and Collecting	$841,987	$962,860	$120,874
Community Relations	$76,962	$42,318	-$34,644
Administrative and General	$1,220,335	$1,225,378	$5,043
Total	**$3,520,680**	**$3,708,394**	**$187,714**

4.3 PROGRAM DELIVERY COSTS WITH VARIANCE ANALYSIS

4.3.1 PROGRAM VARIANCES AND DESCRIPTIONS

ORPC tracks its O&M costs at a financial statement grouping level and at an individual general ledger account level. The prior Cost of Service noted that ORPC was in the process of implementing certain programs, however with staffing changes and challenges, these programs were not implemented. However, all costs are regularly reviewed by management and the Board of Directors by comparing year over year and actual over budget by financial statement grouping and further by individual general ledger account as the year progresses. The financial statement groupings include:

- Distribution Operation and Maintenance
- Community Relations
- Billing and Collecting
- General and Administrative
- Depreciation and Amortization
- Unregulated Expenses
- Interest and Bank Charges
- Interest on Long-Term Debt

If it is noted that the utility will be over budget based on the results to date, ORPC reviews it's planned and expected expenditures to determine if the expenditure can be delayed into the next fiscal year. If it is expected that the utility will be under budget, then consideration is given to advancing projects planned for the next fiscal year into the current fiscal year. ORPC also assesses its needs on an ongoing basis to determine if any other expenditure will become necessary based on the changing conditions of assets and the changing IT and regulatory environments. ORPC also reviews its processes for efficiencies and may determine that additional expenditures can proceed in order to reduce future costs.

The analysis utilized by ORPC is identical to the variance analysis presented in sections 4.2.1 and 4.2.2.

4.4 WORKFORCE PLANNING AND EMPLOYEE COMPENSATION

ORPC currently employs 26 employees, including:

- A President and CEO
- An Executive Administrative Assistant
- An Engineering and Customer Service Manager
- A Meter Technician
- An IT/Network Technician
- A Maintenance Person
- A CFO
- A Financial Assistant
- An Office Manager
- 6 Data Clerks
- Operations Manager
- 10 linesmen

The President and CEO is responsible for managing the overall operation of the corporation while staying in compliance with the ORPC mission statement.

The CFO is responsible for the financial activities and rate settings for the company including liaison with banks. He also provides financial reports to the Board of Directors and its shareholders.

The Engineering and Customer Service Manager is responsible for the coordinating various electricity distribution system projects and ensuring high levels of customer service satisfaction throughout all departments within the organization.

The Office Manager is responsible for the billing department including external communications with customers, as well as assistance on customer billing.

The Operations Manager has the responsibility of supporting the operations staff in both Pembroke and Almonte. He maintains capital and maintenance budgets and executes capital and maintenance projects for the LDC.

4.4.1 COMPENSATION - NON-UNION/UNION

Compensation

Ottawa River Power is committed to making the company increasingly safe, secure and efficient. To succeed in an environment of increased growth, budget constraints, technological advances to the grid, Green Energy Act and regulatory changes, Ottawa River Power must recruit and retain individuals with the appropriate skill set to remain current and competitive. In order to meet this challenge, Ottawa River Power requires employees who are skilled, creative and committed to accomplishing the company's objectives.

In an industry faced with challenges of a competitive labour market, Ottawa River Power must position itself to attract, motivate and retain the talent that is critical to maintaining and renewing its distribution system. Therefore, Ottawa River Power's total compensation package and ability to offer a rewarding work experience must enable it to compete successfully for employees with the requisite skill sets. To avoid falling behind the market rates, it is important that on-going maintenance of the compensation system be done as well. As a result, each year any recommended compensation adjustments are based on market data from various HR consultants and industry projections. ORPC's workforce is comprised of non-unionized and unionized employees where the Collective Bargaining Agreement is presently in effect until June 30, 2024.

Unionized Employees

IBEW Local 636 is the sole bargaining agent for over 70 percent of Ottawa River Power's employees. Compensation for unionized employees is negotiated through the collective bargaining process. When negotiating wage levels, consideration is given to the skill sets required to work within the distribution system, as well as the competitive wage levels of its geographic market.

Ottawa River Power has two Collective Agreements with IBEW Local 636 representing both Office and Trades workers. Ottawa River Power's present contract is effective from July 1, 2019 until June 30, 2024. Wage increases were negotiated at 2.65 percent for each contract year. This is consistent with other negotiated settlements with the LDCs in its geographic area. The previous negotiated wages increase were 2.85% per year from 2014 until 2019.

Management and Non Union Employees

Ottawa River Power provides its non-unionized employees consisting of the Executive, Managers and other Non-union staff with a compensation package comprised of a base salary.

Ottawa River Power has a formal and disciplined approach in awarding merit increases to employees. Merit pay is intended to provide a system to reward employee's success and achievement through increases to base pay. Most increases are however consistent with the increases in the Collective Bargaining Agreement for unionized employees.

In order to ensure Ottawa River Power remains competitive in their compensation package for their non-union staff it takes part in the Management Salary Survey from MEARIE.

4.4.2 PENSION AND BENEFITS

OMERS Pension Plan

The employees of all LDCs are required to participate in the OMERS retirement plan. Therefore, the pension benefits provided to the employees of Ottawa River Power are consistent with the pension benefits provided to employees of other LDCs. This plan is a contributory plan with employees contributing 50 percent of the premiums and Ottawa River Power contributing 50 percent.

Employee Benefit Plan

A comprehensive and competitive benefits package exists which includes health and dental insurance, life insurance, vacation and leave policies. The plans are designed to address the health and wellness needs of the employee.

All benefit plans for each employee group are identical. The unionized benefit plans, negotiated through collective bargaining, play a significant role in driving the plan design for the non-unionized employees, with most plan provisions remaining common across all employee groups.

Post age 65 retirement benefits include only reduced Life insurance in which Ottawa River Power Corporation pays 100% of the premium.

Table 18 – OEB Appendix 2-K – Employee **Compensation** below shows employee compensation from 2016 actuals to 2022. The number of employees is based on the compensation of the number of full-time equivalent (FTE) positions throughout each of the fiscal years.

A detailed summary of benefit program costs is presented below:

Table 17 – Benefit Expenses

	2016	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*
Benefit	Actual	Actual	Actual	Actual	Actual	Bridge	Test
CPP & E.I.	$92,584	$81,455	$84,824	$92,602	$89,626	$87,432	$92,569
WSIB	$17,961	$18,787	$20,711	$21,027	$17,510	$19,516	$20,663
Company Health Benefits	$137,183	$171,263	$206,474	$192,336	$204,541	$195,161	$206,627
OMERS	$166,583	$168,446	$189,841	$192,515	$207,659	$230,290	$243,820
Health - EHT	$34,921	$36,157	$39,177	$39,866	$38,414	$38,056	$40,292
Total Benefit Costs	**$449,231**	**$476,107**	**$541,026**	**$538,345**	**$557,751**	**$570,454**	**$603,970**

As per Table 19 below, Total Compensation have increased 14.9% between the 2016 Actual and 2022 Test Years as a result of statutory rate increases, health benefit increases, CPP and EI rate changes, increases due to inflation and increases per the Collective Bargaining Agreement.

Table 18 – OEB Appendix 2-K – Employee Compensation

	Board Approved	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
	2016	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Number of Employees (FTEs including Part-Time								
Management (including executive)	6	5	6	6	5	6	6	6
Non-Management (union and non-union)	22	21	20	20	21	20	20	21
Total	28	26	26	26	26	26	26	27
Total Salary and Wages including overtime and incentive pay								
Management (including executive)	$564,694	$568,280	$511,047	$599,304	$537,136	$529,565	$619,198	$623,959
Non-Management (union and non-union)	$1,489,691	$1,222,519	$1,343,179	$1,409,748	$1,507,262	$1,497,540	$1,455,182	$1,572,299
Total	$2,054,385	$1,790,799	$1,854,226	$2,009,052	$2,044,398	$2,027,105	$2,074,380	$2,196,258
Total Benefits (Current + Accrued)								
Management (including executive)	$106,382	$136,349	$134,518	$166,733	$147,629	$145,000	$170,279	$171,589
Non-Management (union and non-union)	$276,547	$312,882	$341,589	$374,293	$390,716	$412,751	$400,175	$432,382
Total	$382,928	$449,231	$476,107	$541,026	$538,345	$557,751	$570,454	$603,970
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$671,076	$704,628	$645,565	$766,037	$684,765	$674,564	$789,477	$795,548
Non-Management (union and non-union)	$1,766,238	$1,535,401	$1,684,768	$1,784,041	$1,897,978	$1,910,292	$1,855,357	$2,004,681
Total	**$2,437,313**	**$2,240,030**	**$2,330,333**	**$2,550,077**	**$2,582,743**	**$2,584,856**	**$2,644,834**	**$2,800,228**
							From last Board Approved	**14.9%**

Employee Compensation costs are estimated to have increased by 14.9% when comparing 2022 projected to 2016 Board Approved amounts. The Collective Bargaining Agreement will see a total increase of 16.3% from 2016 to 2022 when considering the negotiated wage increases. The existing CBA, which was negotiated in 2019, is effective through 2024. ORPC typically applies the same percentage increase to non-union staff therefore the increase in the CBA is the increase reflected on all wages.

The Number of Employees represents the headcount as at December 31st of each fiscal year. This number decreased by 2 in 2016 when comparing to Board Approved totals due to multiple retirements, parental leaves and terminations. This figure has remained at 26 each year mainly due to employee rotation indicating that there were 2 vacancies at the end of each year although they have not been the same 2 vacant positions each year. There are currently 2 vacancies at ORPC based on the last approved Cost of Service headcount, however ORPC is proposing to retain 1 of those in its 2022 figures. The following table details the changes in FTEs per position:

Table 19 – Employee FTE Count by Position

Position	BA	2016	2017	2018	2019	2020	2021	2022
President & CEO	1	1	1	1	1	1	1	1
CFO	1	0	1	1	1	1	1	1
Operations Manager	1	1	1	1	1	1	1	1
CDM Manager	1	1	1	1	1	1	1	1
Office Manager	1	1	1	1	1	1	1	1
Engineering, IT and Customer Service Manager	1	1	1	1	0	1	1	1
Total Management	**6**	**5**	**6**	**6**	**5**	**6**	**6**	**6**
Linesman	8	8	9	9	9	9	9	9
Data Clerk	7	7	6	6	6	6	6	6
Cashier	1	1	1	1	1	0	0	0
Meter Technician	1	1	1	1	1	1	1	1
Substation Electrician	1	1	1	1	1	1	1	1
Engineering Technician	1	1	0	0	1	0	0	1
IT/Network Administrator	1	0	0	0	1	1	1	1
Maintenance Worker	1	1	1	1	1	1	1	1
Executive Assistant	1	1	1	1	0	1	1	1
Total Non-Management	**22**	**21**	**20**	**20**	**21**	**20**	**20**	**21**

Management saw a vacancy in the CFO position in 2016 and in the Engineering, IT and Customer Service Manager in 2019 but is now fully staffed. Non-Management saw a decrease to 21 in 2016 from the board-approved amount with a vacancy in the IT/Network Administrator position. This decreased again to 20 in 2017 with a vacancy in the Engineering Technician position. In 2018, the total increased to 21 while filling the two previous vacancies but the Executive Assistant position became vacant at the end of 2019. This position was no longer vacant in 2020 but the Engineering Technician and Cashier positions saw 1 vacancy each decreasing the total to 20. Due to the pandemic, it is not expected that the Cashier position will be filled in 2022 but the Engineering Technician position will be filled.

Total Salary and Wages has only seen an increase of 6.9% from the 2016 Board Approved amounts to 2022 due to these vacant positions. Total Benefits has seen an increase of 57.7%. This increase is primarily composed of a 49.1% increase in health benefit costs from 2016 to 2020 and an increase in CPP rates seeing the maximum contributory earnings increase by 13% and the contribution rate increase by 10% from 2016 to 2021. The following table represents the year over year variance of total salaries and wages and of benefits:

Table 20 – Salaries and Wages and Benefits Variances

	BA-16	16-17	17-18	18-19	19-20	20-21	21-22
Salaries and Wages	$(263,586)	$63,427	$154,826	$35,346	$(17,293)	$47,275	$121,878
Benefits	$66,303	$26,876	$64,919	$(2,681)	$19,406	$12,703	$33,516
Total ($)	$(197,283)	$90,303	$219,745	$32,665	$2,113	$59,978	$155,394
Total (%)	(8.1)%	4.0%	9.4%	1.3%	0.1%	2.3%	5.9%

Please find below the variance explanations regarding variances above $50,000.

BA to 2016 – Decrease of $(197,283)

The Board Approved amounts included salaries and benefits for the CFO and IT/Network Administrator Positions. These were vacant in 2016 due to unanticipated staffing changes. The Benefits cost increased due to continued benefit costs related to terminated employees and increases in premiums from the vendor.

2016 to 2017 – Increase of $90,303

A portion of the increase relates to a 2.8% increase per the Collective Bargaining Agreement. The remainder relates to the filling of the CFO position part way through the year combined with an increase of 1 linesman and an Engineering Technician vacancy.

2017 to 2018 – Increase of $219,745

There was an increase in health benefits of 21% in 2018 due to premium increases from the vendor combined with multiple staffing changes, retirements and maternity leaves. Part of the increase also pertains to costs to train a new Office Manager and Executive Assistant and 2018 being the first full year that the new CFO was employed.

2020 to 2021 – Increase of $59,978

The increase pertains mostly to an expected 2.65% increase per the Collective Bargaining Agreement.

2021 to 2022 – Increase of $155,394

The increase pertains to an expected 2.65% increase per the Collective Bargaining Agreement and the filling of the vacant Engineering Technician position.

4.4.3 POST-EMPLOYMENT RETIREMENT BENEFITS (OPEBS)

ORPC participates in the OMERS retirement plan and pays for life insurance premiums for its retired members. The table below shows the historical OPEB costs included in OM&A. A breakdown of the pension and OPEBs amounts included in OM&A is provided below.

Table 21 – Post Employment Benefits

	OPEB Costs	OMERS Costs
2016	$28,806	$166,583
2017	$31,104	$168,446
2018	$31,187	$189,841
2019	$32,027	$192,515
2020	$33,172	$207,659
2021	$33,835	$230,290
2022	$34,512	$243,820

Pension and OPEB costs are proposed to be recovered cash basis as has been the case in previous applications. ORPC understands that cash basis is contrary to the Board's default preference for the accrual accounting methodology. However, continuing a cash basis maintains consistency with the previous COS decision and past practice as actuarial evaluations could fluctuate the expense significantly year to year. The rational for using a cash basis is:

a) Pension and OPEB costs were included in rates on a cash basis in 2016, such that changing to accrual now and going forward would require a review of the transition impacts. This is consistent with board policy, which cites consistency as one reason to support an alternate method promoting stability and predictability in;

b) Because ORPC participates in the OMERS pension plan, there is no difference between the accrual and cash accounting methods in terms of end value. OMERS does not require an actuarial evaluation; and

c) The fees paid on life insurance premiums to retirees requires an actuarial evaluation. This allows for the liability and expense to fluctuate significantly year over year with the interest rates set by the banks. Using a cash method ensures consistent year over year. Additionally, only items paid in cash for OPEB are deductible for PILs purposes.

ORPC performs a full actuarial valuation on the retirement life insurance plan every 3 years and small updates in the years in between. The most recent full Actuarial Report is provided at Appendix D.

4.4.4 STAFFING AND COMPENSATION STRATEGY

Finding qualified staff in smaller rural areas can be challenging, therefore, similar to other smaller utilities ORPC prefers to invest time and energy in training its existing employees rather than hiring skilled workers.

In doing so ORPC must also balance reliance on third party contractors and use its workforce to its best advantage for the customer and community. The utility evaluates on a yearly basis its agreements with its consultants and contractors to ensure that they are the best option possible for the utility.

ORPC does not use specific benchmarking studies to determine salary ranges. That said, ORPC is aware of the salary ranges in similar utilities in Ontario and salary ranges of local similar workforces and use these salaries as a guideline.

Salaries to both union and non-union employees are adjusted based on the negotiated increases in the Collective Bargaining Agreement. When the agreement is negotiated, management and the utility's Board of Directors will review and assess employee salaries to ensure they are competitive with its neighboring cohorts. It is also important to note that as existing non-union staff gain training and expertise, management may choose to increase salaries according to new qualifications and experience.

The salaries and wage amounts include all salaries and wages paid, inclusive of overtime, and vacations. The benefit amounts include the employer's portion of statutory holidays, sick leave, bereavement leave, union meetings and other miscellaneous paid leave or labor dispute settlement amounts, Provincial benefits (CPP and EI), employer contributions to EHT, WSIB, OMERS pension plan and ORPC's costs for providing extended health care, dental, long-term disability, life insurance and the Employee Assistance Program.

Employee Staffing Levels:

The level of staffing has not changed since its last Cost of Service and there are no anticipated staffing increases for the 2022 Test Year.

4.5 SHARED SERVICES & CORPORATE COST ALLOCATION

ORPC provides services to and receives services from Ottawa River Energy Solutions Inc. ORPC and ORES share the same ownership structure rendering the two sister companies.

The Services Agreement between ORPC and ORES was effective on April 21, 2017 with the term ending April 20, 2022. This agreement is provided in Appendix A. Pursuant to the Services Agreement, ORPC provides water heater, sentinel light, fibre, solar and other maintenance services to ORES. These services include all associated accounting, administrative and billing and collecting services. These services stem from historical retail lines of the former amalgamated utilities. Ottawa River Energy Solutions provides internet services to Ottawa River Power on market-based pricing.

Although ORES does not have any employees, ORES utilizes the physical space of ORPC. ORPC applies a markup of 30% after burdened costs are applied to capture ORES' utilization of indirect costs related to access to client reception area, central communication, cashiering services, the inventory warehouse and maintenance and other services. All direct costs, including burdened labour, materials and vehicle time, are invoiced on a monthly basis to ORES. The revenues and expenses by service provided are detailed in Appendix 2-N Shared Services/Corporation Cost Allocation. In accordance with Article 340 of the APH, the utility confirms that there is no cross-subsidization between regulated and non-regulated or non-rate-regulated distributor lines of business. The pricing methodology outlined below adheres to the ARC's transfer pricing rules. No Board of Director costs for affiliates have been included in LDC costs. The OEB Appendix 2-N Shared Services/Corporate Cost Allocation is presented at the next page.

Board of Directors

Ottawa River Energy Solutions Inc. has a seven member Board of Directors that is separate from Ottawa River Power Corporation. This is comprised of four members appointed by the City of Pembroke, and one member from the remaining three communities: Town of Mississippi Mills, Township of Whitewater and Township of Killaloe, Hagarty & Richards.

Pricing Methodology

The services provided by Ottawa River Power Corporation to Ottawa River Energy Solutions Inc. are charged on a cost basis (including labour burdens of 44.23%) plus a 30% markup to ensure the utility earns a fair return and covers all indirect associated costs for shared space. A project and job costing system is used to track time, material and equipment for the services provided.

OEB Appendix 2-N Shared Services/Corporate Cost Allocation is presented below for 2016 to 2020 historicals.

Shared Services and Corporate Cost Allocation

Year: **2016**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Administration	Burdened Cost	54,758.55	54,758.55
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Electrical Contracting	Burdened Cost + 15%	210,451.50	184,120.27
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Street and Traffic Light Contracting	Burdened Cost + 15%	63,902.77	55,373.75
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Water Heater Maintenance	Burdened Cost + 15%	28,559.45	24,834.25

Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Fibre Maintenance	Burdened Cost + 15%	54,811.69	47,662.27
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Solar Maintenance	Burdened Cost + 15%	16,067.75	13,971.93
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Sentinel Light Maintenance	Burdened Cost + 15%	3,214.72	2,795.10

Year: **2017**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Administration	Burdened Cost	50,932.86	50,932.86
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Electrical Contracting	Burdened Cost + 15%	238,168.37	192,816.94
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Street and Traffic Light Contracting	Burdened Cost + 15%	71,778.26	62,220.11
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Water Heater Maintenance	Burdened Cost + 15%	4,446.70	3,866.65
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Fibre Maintenance	Burdened Cost + 15%	9,752.80	8,480.65
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Solar Maintenance	Burdened Cost + 15%	53,210.35	46,260.82
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Sentinel Light Maintenance	Burdened Cost + 15%	1,895.95	1,648.63

Year: **2018**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Administration	Burdened Cost	55,140.20	55,140.20
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Electrical Contracting	Burdened Cost + 15%	407,678.59	336,648.22
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Street and Traffic Light Contracting	Burdened Cost + 15%	64,569.20	54,754.36

Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Water Heater Maintenance	Burdened Cost + 15%	1,939.17	1,686.21
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Fibre Maintenance	Burdened Cost + 15%	11,659.95	9,736.29
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Solar Maintenance	Burdened Cost + 15%	220.61	191.83
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Sentinel Light Maintenance	Burdened Cost + 15%	3,593.58	3,124.83

Year: **2019**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Administration	Burdened Cost	60,589.96	60,589.96
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Electrical Contracting	Burdened Cost + 15%	246,370.31	208,265.64
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Street and Traffic Light Contracting	Burdened Cost + 15%	357,228.07	338,946.39
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Water Heater Maintenance	Burdened Cost + 15%	2,194.52	1,908.26
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Fibre Maintenance	Burdened Cost + 15%	4,759.21	4,142.42
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Solar Maintenance	Burdened Cost + 15%	494.74	430.20
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Sentinel Light Maintenance	Burdened Cost + 15%	2,589.58	2,250.17

Year: **2020**

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Administration	Burdened Cost + 15%	94,527.39	91,270.82
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Electrical Contracting	Burdened Cost + 15%	172,499.14	138,047.77

Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Street and Traffic Light Contracting	Burdened Cost + 15%	163,975.26	142,243.26
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Water Heater Maintenance	Burdened Cost + 15%	9,448.81	8,216.35
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Fibre Maintenance	Burdened Cost + 15%	8,726.78	7,317.23
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Solar Maintenance	Burdened Cost + 15%	115.00	100.00
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	Sentinel Light Maintenance	Burdened Cost + 15%	3,960.11	3,443.58
Ottawa River Power Corporation	Ottawa River Energy Solutions Inc.	EV Charging Station Maintenance	Burdened Cost + 15%	1,537.84	1,337.25

4.6 PURCHASES OF NON- AFFILIATE SERVICES, ONE TIME COST, REGULATORY COSTS

4.6.1 NON-AFFILIATE SERVICES

ORPC purchases goods and services based on overall price as well as product quality, the ability to deliver on time, reliability, environmental impact, safety record of contractors, preference to support local suppliers, standardization of equipment and the impact on the ongoing work process.

The procurement of goods and services for ORPC is carried out with highest of ethical standards and consideration to the public nature of the expenditures.

ORPC's purchasing policy reads as follows:

Aim

To provide fairness to suppliers and assure value to ORPC customers in the purchasing of goods and services. More specifically the procurement of goods and services will be based on:

1. Overall price impact for ORPC
2. Quality of goods
3. Reputation and performance of supplier
4. Delivery
5. Environmental impact
6. Safety record of contractors
7. Preference to support local suppliers, based on (in order) suppliers who are customers of ORPC, local suppliers, provincial suppliers, national suppliers
8. Standardization of equipment
9. Impact on the ongoing work process
10. Guidelines

Authorization

The authorization level for purchasing for goods and services that have been approved in the capital and operating budget is as follows:

Less than $200	
$200 to $20,000	Supervisors
>$20,000	President or Delegate

For goods and services not approved in the capital or operating budgets:

Less than $10,000	President or Delegate
>$10,000	Board

Process

Normally the requirements will follow the following routines:

RFP (Request for Proposal	To be issued for goods and services that are being considered for purchase that are not well defined and are of higher value. RFP may be followed up using a tender process or a purchase decision may be made based on the RFP.	
Tender	Formal tender process for goods and services >$20,000 or items of complex nature that require well defined specifications and terms and conditions. Fixed closing date/time and official opening by two staff required.	
Quotation	Fax, e-mail or telephone quotations >$200	

Single Source	-For emergency work or sole source vendor work/ goods should be limited to the minimum amount to respond to the emergency -For goods and services <$1000	
Cash	<$200	

Evaluation of Bids

Criteria for evaluation of tenders should be included within the request for tender/quotations whenever possible. Evaluation criteria such as reputation, performance record, etc. are more subjective and should be weighed in view of the risk to the utility and the need to encourage/developer the supplier pool.

Construction Contractors

Acquiring services from construction contractors needs special attention due to the contractual obligations under the OH&S act. The Quotation/Tender process has to provide adequate assurance that the contractor has the skills and competence for the work to be performed and they have an acceptable H&S Program in place.

Service Provider

ORPC has a number of service contracts that are integral to the operation of the utility. While it is possible to re-tender these contracts on a regular bases changing of suppliers would be disruptive to the operation of the utility. These services will be reviewed on ongoing basis to assure that the value is received and ORPC continues to receive competitive pricing.

Supplier Alliances

Agreements may be established with key supplies to form an alliance whereby benefits flow to both parties that can include: reduced inventory levels, improved service levels, etc. Vendor alliances should be reviewed on an annual basis to assure that ORPC is receiving value from the arrangement.

4.6.2 ONE TIME COSTS

There is only one material one-time cost included in the Test Year, the regulatory costs associated with the Cost of Service application. In compliance with policy and requirements, the costs are being amortized over a period of 5 years. Regulatory Costs, which are explained in detail in the next section, include costs related to the Distribution System Plan, third party accounting and interrogatory fees. These costs apply to the 2021 and 2022 Bridge & Test Year.

With the exception of Regulatory Costs, all other costs presented in the OM&A are considered regular year over year expenses.

4.6.3 REGULATORY COSTS

The costs related to Cost of Service application include costs of having an Engineering firm develop the Distribution System Plan, legal review, consulting assistance, external accounting fees related to the depreciation.

The regulatory costs proposed in this application do not include provisions for legal fees related to a written hearing. If the parties are unable to reach a full settlement, ORPC reserves the right to add hearing costs to the total OM&A for the test year. All regulatory costs listed below are tracked in account 5655 – Regulatory Expenses. Costs directly associated with the Cost of Service application are amortized over a period of 5 years (2022-2026).

Table 22 – Regulatory Costs specific to the 2021 Cost if Service

	Regulatory Cost Category	USoA Account	Last Rebasing Year (2016 OEB Approved)	Last Rebasing Year (2016 Actual)	Most Current Actuals Year 2020	2021 Bridge Year	Annual % Change	2022 Test Year	Annual % Change
	(A)	(B)	(D)	(E)	(F)	(G)	(H)=[(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
	Regulatory Costs (Ongoing)								
1	OEB Annual Assessment	5655		$44,654	$47,025	$34,061	-27.57%	$46,000	35.05%
2	OEB Section 30 Costs (OEB-initiated)								
3	Expert Witness costs for regulatory matters								
4	Legal costs for regulatory matters								
5	Consultants' costs for regulatory matters								
6	Operating expenses associated with staff resources allocated to regulatory matters								
7	Operating expenses associated with other resources allocated to regulatory matters [1]								
8	Other regulatory agency fees or assessments								
9	Any other costs for regulatory matters (please define)								
10	Intervenor costs				$2,640		-100.00%		
11	OEB and Intervenor Cost Awards for non-ORPC matters	5655		$959	$2,494	$2,537	1.73%	$2,500	-1.46%
12	Safety and Satisfaction Surveys	5655		$14,130	$5,642	$9,572	69.67%	$10,000	4.47%
13	Amortization of 2016 COS	5655		$30,377	$52,074	$21,698	-58.33%		-100.00%
14	External Auditor Fees	5655		$28,200	$49,953	$49,862	-0.18%	$49,862	0.00%

Regulatory Costs (One-Time)									
1	Expert Witness costs								
2	Legal costs	1460	$113,302					$30,000	
3	Consultants' costs	1460	$77,434					$30,000	
4	Incremental operating expenses associated with staff resources allocated to this application.								
5	Incremental operating expenses associated with other resources allocated to this application. [1]								
6	Intervenor costs	1460	$69,636					$75,000	
7	OEB Section 30 Costs (application-related)								
8	DSP	1460						$60,000	
9	Asset Condition Assessment	1460						$24,000	
10	ACA/DSP	1460						$120,000	
11	Survey	1460						$16,000	
12	Accounting Assistance	1460						$15,500	
15	Production & Submission	1460						$1,000	
16	Public Notice	1460						$2,000	
20	Actuary Fees	5655		$500					
1	Sub-total - Ongoing Costs [2]		$0	$118,319	$ 159,828	$117,730	-26.34%	$108,362	-7.96%
2	Sub-total - One-time Costs [3]		$260,372	$500	$ -	$0		$373,500	
3	Total		$260,372	$118,819	$ 159,828	$117,730	-26.34%	$183,062	55.49%

The table above shows a breakdown of average costs for the Cost of Service. The predicted regulatory costs of for 2022 are $183,062 which is comprised of $108,362 of on-going costs plus 1/5 of the one-time costs of $373,500 ($74,700) relating to the preparation and proceedings of the 2022 Cost of Service application.

In its 2016 Cost of Service, the OEB approved $105,000 in regulatory costs per year which included $52,074 per year for the amortization of the 2016 Cost of Service applications from 2016 to 2021. The 2016 regulatory costs included OEB assessment, OEB Section 30 Costs, consulting costs, costs association with the development of the DSP and intervener costs.

4.7 LEAP, CHARTIABLE & POLITICAL DONATIONS

ORPC has included $7,500 of expense for the Low-Income Assistance Program (LEAP) under Deductions Donation Expense (USoA #6205). This amount is based on historical LEAP funding provided to ORPC customers and is higher than the Board's determination of 0.12% of a distributor's Board-approved distribution revenue requirement.

ORPC has partnered with Ontario Works in Pembroke and the Department of Social Services – Lanark County in Almonte to assist in program intended to provide emergency relief to eligible low-income customers who may be having trouble paying current arrears be our lead agency.

In compliance with OEB policy, ORPC:

- Collects money from ratepayers for LEAP EFA in the amount approved by the OEB;
- Transfers program funds to the customer based on approvals from Ontario Works in Pembroke and the Department of Social Services – Lanark County in Almonte;
- Establish partnerships, contracts, and operational procedures with Lead Agencies;
- Receives, records and takes appropriate action upon notification from an Intake Agency (or Lead Agency as appropriate) that an assessment of eligibility is being undertaken;
- Receive, recording and taking appropriate action upon notification from an Intake Agency (or Lead Agency as appropriate) of decisions on applications; and
- Confirm customer and account information used in determining program eligibility, including information on payment history.

ORPC Reports to the OEB in accordance with OEB reporting requirements through filings 2.1.16.

ORPC attests that the test year revenue requirement does not includes legacy low-income energy assistance programs.

4.9 TAXES & PAYMENTS IN LIEU OF TAXES (PILS)

4.9.1 OVERVIEW OF PILS

ORPC is required to make payments in lieu of income taxes ("taxes") based on its taxable income. ORPC files Federal/Provincial tax returns annually.

There have been no special circumstances that would require specific tax planning measures to minimize taxes payable.

ORPC has been selected for an audit of its 2017 and 2018 tax returns. ORPC expects no or immaterial adjustments once the audit is complete. There are no outstanding reassessments or disputes relating the tax returns filed by ORPC.

ORPC has used the OEB PILs Tax Work Form model to calculate the amount of taxes for inclusion in its 2021 rates. PILs have been calculated under MIFRS accounting policies.

The PILS model was completed by ORPC. ORPC ensured that the current and proposed tax rates have been applied, that the amount of PILS calculated appears reasonable and that the integrity checks established in the Boards Minimum Filing Requirements have been adhered to.

ORPC's taxes for the 2022 Test Year, under the new accounting policies, amount to $0.

The income tax sheet from the Revenue Requirement Work form is presented on the next page, and the PILs model is being filed in conjunction with this application. Actual most recent federal and provincial tax returns are presented in Attachment 1 of this Exhibit.

ORPC pays the following property taxes which are set by the Towns and for which ORPC has no control over.

Table 23 – Property Taxes

	Property Taxes
2016	$61,815
2017	$52,262
2018	$47,427
2019	$50,206
2020	$51,549
2021	$52,126

2022	$53,168

Table 24 – Tax Provision for the Test Year

Particulars	**Application**
Determination of Taxable Income	
Utility net income before taxes	$443,101
Adjustments required to arrive at taxable utility income	-$486,050
Taxable income	-$42,949
Calculation of Utility income Taxes	
Income taxes	-$9,272
Capital taxes	$ -
Total taxes	$ -
Gross-up of Income Taxes	$ -
Grossed-up Income Taxes	$ -
PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$ -
Other tax Credits	$ -
Tax Rates	
Federal tax (%)	15.00%
Provincial tax (%)	11.50%
Total tax rate (%)	26.50%

The anticipated loss of $9,272 is expected to be utilized in the next fiscal year as CCA is expected to decrease in 2023 resulting in a tax provision.

The utility's latest tax return is included as Appendix 4B of this Exhibit.

ORPC confirms that it has use of the stand-alone principle when determining PILs amounts. ORPC has verifed the following information:

- ✓ it has exercised sound tax planning and that for rate setting purposes, it maximized tax credits and take the maximum deductions allowed if it made sense for the utility to do so.

- ✓ It has excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts.
- ✓ A copy of the most recent Federal and Provincial tax is presented in Attachment 2 of this Exhibit.
- ✓ Detailed calculations of Income Tax or PILs are shown in the OEB PILs model filed along with this application.
- ✓ Adjustments to incorporate Accelerated CCA were made for the Bridge and Test Years and as such an additional supporting document entitled "PILs Accelerated CCA Calculation" is submitted in conjunction with the PILs model. The difference to account for accelerated CCA was presented as a separate line item on the Schedule 8 of the PILs model.

4.10 NON- RECOVERABLE AND DISALLOWED EXPENSES

ORPC confirms that expenses that are deemed non-recoverable in the revenue requirement (e.g. individual charitable donations) or disallowed for regulatory purposes have been excluded from the regulatory tax calculation.

4.11 PILS INTERGRITY CHECK

ORPC confirms to the best of its knowledge that the following integrity checks have been completed in its application. In completing the PILs model, ORPC confirms that;

- ✓ 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;
- ✓ the capital additions and deductions in the UCC/ CCA Schedule 8 agree with the rate base section for historical, bridge and test years;
- ✓ Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st;
- ✓ The CCA deductions in the application's PILs tax model for historical, bridge and test years agree with the numbers in the UCC schedules for the same years filed in the application;
- ✓ Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application;
- ✓ CCA is maximized even if there are tax loss carryforwards; and
- ✓ A statement is included in the application as to when the losses, if any, will be fully utilized.

4.12 CONSERVATION AND DEMAND MANAGEMENT

4.12.2 LRAM VARIANCE ACCOUNT (LRAMVA)

Distributors are required to track the variances between the OEB approved CDM adjustment to their load forecasts and the actual CDM results in the LRAMVA for the 2015 - 2020 period. ORPC's LRAMVA claim is for the energy savings achieved through the delivery of province wide CDM programs over the period January 2015 to March 2019.

ORPC's CDM activities consist of programs initiated by the Independent Electricity System Operator ("IESO").

ORPC is seeking LRAMVA recovery of $177,787, including carrying charges to the end of April 2021. The Applicant has not claimed for LRAMVA recovery of revenue since the LDC's 2016 Cost of Service.

Through this application, ORPC is seeking approval to recover the LRAMVA balances for:

a) New lost revenues achieved from CDM kWh energy saving programs delivered under Conservation First Framework (CFF) from January 2015 to December 31, 2017.
b) The resulting persistence of kWh energy savings for years 2016, 2017, 2018 from the delivery of CDM programs under CCF between January 2015 to December 31, 2017; and

ORPC has completed the OEB's LRAMVA Work Form (excel) and has filed this evidence with this application.

ORPC confirms that the data used in the LRAMVA model, as filed with this application, is derived from the following sources:

- The distributor's final CDM Report and Persistence Savings Report as published by the IESO. This includes the 2011-2014 Final Results Report, Final 2015 Annual

Verified Results Report, Final 2016 Annual Verified Results Report, the Final 2017 Annual Verified Results Report: and

- The IESO's P&C report issued in April of 2019.

ORPC has relied on the most recent verified input assumptions available at the time of program evaluation as detailed in the publications listed above.

Copies of the IESO's annual distributor report for ORPC for years 2016, 2017 and 2018 have been filed as excel files with this Application in Appendix 4A.

The table below shows the total LRAM principal amount and carrying charges that ORPC is requesting for recovery of through this application:

Table 25 – Summary of Requested LRAM Amounts

Description	**Residential**	**GS<50 kW**	**GS 50-1499 KW**	**Sentinel**	**Street Lighting**	**USL**	**Total**
	kWh	kWh	kW	kW	kW	kW	
2016 Actuals	$8,615.51	$12,209.42	$2,856.81	$0.00	$0.00	$0.00	$23,681.74
2016 Forecast	($8,962.89)	($3,871.14)	($6,481.56)	($15.15)	$0.00	($14.14)	($19,344.88)
Amount Cleared							
2017 Actuals	$27,513.94	$32,520.42	$12,672.80	$0.00	$0.00	$0.00	$72,707.16
2017 Forecast	($15,030.08)	($7,742.27)	($13,101.38)	($30.63)	$0.00	($29.11)	($35,933.47)
Amount Cleared							
2018 Actuals	$19,862.47	$40,433.55	$19,363.53	$0.00	$0.00	$0.00	$79,659.56
2018 Forecast	($10,755.47)	($7,865.16)	($13,249.47)	($30.97)	$0.00	($29.11)	($31,930.18)
Amount Cleared							
2019 Actuals	$11,137.56	$40,728.35	$19,576.15	$0.00	$0.00	$0.00	$71,442.06
2019 Forecast	($6,205.08)	($7,926.61)	($13,395.28)	($31.32)	$0.00	($29.11)	($27,587.39)
Amount Cleared							
Carrying Charges	$0.00	$40,858.98	$19,920.13	$0.00	$0.00	$0.00	$60,779.11
2020 Actuals	$0.00	($8,110.95)	($13,697.49)	($32.02)	$0.00	($29.94)	($21,870.40)
2020 Forecast							
Amount Cleared	$1,313.59	$4,698.36	$181.82	($5.45)	$0.00	($5.13)	$6,183.20
Total LRAMVA Balance	**$27,490**	**$135,933**	**$14,646**	**-$146**	**$0**	**-$137**	**$177,787**

ORPC has used the most recent verified input assumptions when calculating lost revenue and has relied on the most recent final evaluation report from the Independent Electricity System Operator (IESO) in support of its LRAM calculation for its contracted province wide CDM programs ("IESO Programs") for 2016 to 2019 with persistence to 2020. Lost revenues are based on Board approved variable charges and carrying charges up until 2021 are requested.

ORPC is not requesting recovery of lost revenue resulting from IESO-approved pilot projects.

None of the estimated CDM load reductions were factored into the load forecast underpinning ORPC's 2016-2021 rates. ORPC has calculated any carrying charges for the applicable periods using the quarterly rates prescribed by the Board.
For further details, please refer to the enclosed Excel OEB LRAMVA Work form, IESO 2017 Final Report and the P&C report issued by the IESO in March of 2019.

APPENDICES

Appendix 4A	IESO Reports for 2016, 2017, 2018 and Final Report
Appendix 4B	PDF of 2020 Income Tax Returns
Appendix 4C	PDF of PILs Model
Appendix 4D	Actuarial Report

Appendix A – IESO reports for 2016, 2017 and 2018 and Final Report

Program Participation & Cost Report
Message from the IESO Reporting Team

The IESO is pleased to provide LDCs with the Monthly Program Participation & Cost Report.

This report is generally posted on the IESO LDC Extranet by the Friday of the week following the 15th of each month. The report provides province-wide and LDC specific program participation and costs to the extent known based on information received by the IESO from all distribution companies and IESO Value Added Service Provider.

The Monthly Program Participation & Cost Report includes preliminary, unverified results based on information received by the IESO. Upon verification of project information through the IESO Evaluation, Measurement and Verification (EM&V) process, results will be reported as 'verified'. Performance against CDM Plan information is also available in this report and is based on the LDC's approved CDM Plan as at the end of the reporting period. Where two or more LDCs have submitted a joint CDM Plan, the IESO will provide a Monthly Program Participation & Cost Report for each LDC included in the CDM Plan.

The IESO would like to advise LDCs of an issue identified with the December 15, 2016 Report. Due to a data error, the Save on Energy Retrofit Program and Save on Energy Retrofit Program – P4P was overstated in the report. The results for the program have been adjusted in this issue of the report. We apologies for any inconvenience this may have caused.

The IESO strives to improve on the current reporting processes to provide meaningful and timely information to LDCs. Your feedback is encouraged and appreciated. Should you have any feedback, questions or comments on this report please contact us at LDC.Support@ieso.ca.

ieso
Connecting Today.
Powering Tomorrow.

Program Participation & Cost Report
Table of Contents

#	Worksheet Name	Worksheet Description
1	Cover Letter	Provides an overview of the IESO Value Added Services Report.
2	How to Use This Report	Describes the contents and structure of this report.
3	Report Summary	A high level summary of the Program Participation & Cost Report, including: 1) Progress toward the LDC's a) Allocated 2020 Energy Savings Target; b) Allocated 2015-2020 LDC CDM Plan Budget; c) CDM Plan 2015-2020 Forecasts; 3) Annual savings and spending; 4) Annual LDC CDM Plan spending progress; 5) Graphs describing: a) Contribution to 2020 Target Achievement by program; b) Program to Date LDC CDM Plan Budget Spending by Sector; c) Annual energy savings persistence to 2020 by year; d) Allocated Target achievement progress relative to other LDCs; and e) LDC CDM Plan Budget Spending progress relative to other LDCs.
4	LDC Progress	A comprehensive report of 2015-20 conservation results including: 1) Activity; 2) Savings including; a) Net Energy; b) CDM Plan forecasts, verified actuals and relative progress; c) Allocated Target and Target achievement; and 3) Spending, including participant incentives and administrative expenses.
5	Province-Wide Progress	A comprehensive report of 2015-20 conservation results including: 1) Activity; 2) Savings including; a) Net Energy; b) CDM Plan forecasts, verified actuals and relative progress; c) Allocated Target and Target achievement; and 3) Spending, including participant incentives and administrative expenses.
6	IESO Value Added Services Costs	Provision of the LDCs and the Province-Wide aggregated IESO Value Added Services activity and costs for each year.
7	Methodology	Description of the methods used to calculate energy savings, financial results and cost-effectiveness.
8	Reference Tables	Consumer Program Province-Wide results allocation to specific LDCs.
9	Glossary	Definitions for the terms used throughout this report.

Program Participation & Cost Report
How to Use This Report

The IESO is pleased to provide you with the Monthly Participation and Cost Report.

This report provides:
  1) program participation;
  1) electricity savings; and
  2) costs
to the extent known based on information received by the IESO in accordance with Section 9.2(c)(i) of the Energy Conservation Agreement.

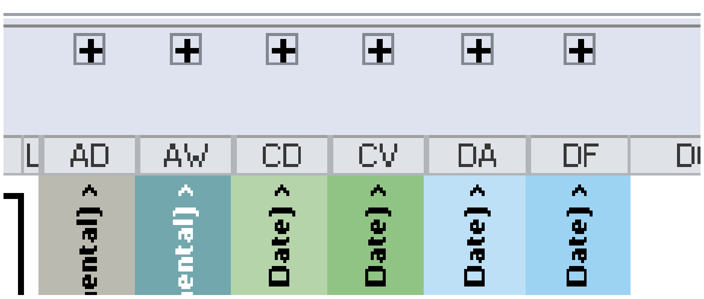
In addition to the above, this report also provides in greater detail:
  1) program participation results including:
     a) forecasts; b) actuals; and c) progress (forecast versus (vs) actuals);

  2) program savings results including:
     a) net 2020 annual energy savings;
     b) allocated target, target achievement and progress towards target;
     c) incremental net first year energy savings;
     and where available reported by: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

  3) program spending including:
     a) participation incentive spending;
     b) administrative expense spending (including IESO value-added services costs);
     c) aggregated total spending;
     and for each cost: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

by both the LDC specific level and the province-wide aggregated level.

This report's format is a dynamic sheet that can be expanded or collapsed by clicking the + button or "Show Detail" feature under the Data tab. Each of the results categories listed above have been grouped together for easy accessibility.



Please note:
  1) Cost Effectiveness Test (CET) results including:
     a) total resource cost test;
     b) program administration cost test;
     c) levelized unit energy cost test;
     will not be available for the 2015 program year in this report but will be provided to LDCs once available.

  2) forecasts of: a) activity; b) savings; and c) spending; included in this report are
     based on LDC submitted and IESO approved CDM Plan - Cost Effectiveness Tools as of the end of the reporting month.
     (from the i) Program Design; ii) Budget Inputs; iii) Savings Results; and iv) CE Results; worksheets);
     Please note that this does not contain data for Legacy Framework program spending or CFF pilot program activity, savings, spending or cost effectiveness.

  3) Annual FCR Progress only includes Full Cost Recovery funded program savings. In future reports, any Pay-for-Performance funded programs will be reported as a separate line item.

  4) The complete list of programs and pilots launched into market in 2015 has been included, however no programs and pilots were in market for a sufficient period of time to enable a valid EM&V process. Therefore these programs and pilots have nothing to report at this time and have cells greyed out rather than reporting zero savings or spending. Any results in 2015 will be determined in a subsequent EM&V process and will be included in a future year's Annual Verified Results Report as a 2015 adjustment;

  5) Pilot program savings are attributed to the LDC where the pilot program project is located in; and

  6) This Monthly Participation and Cost Report provides results for the LDC and province only. No aggregated reporting is provided for LDCs that are part of a joint CDM plan;

Program Participation & Cost Report
Summary

	CDM Plan	vs	Allocated	Paid Pre-Funding
CFF Target (kWh):	8,724,947		8,719,912	
CFF Budget:	$2,282,359		$2,282,373	$91,531

Ottawa River Power Corporation
As of: 31-Dec-16

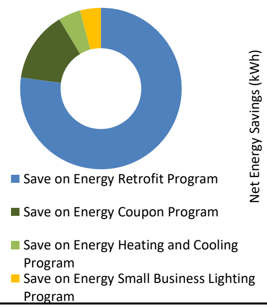
Summary of Performance Metrics

	2016 CDM Results	2016 CDM Plan %	6-year CDM Results	6-year CDM Plan %	6-year Allocated %
Net Energy Savings (kWh)	1,491,483	151%	4,429,677	49.3%	49.3%
Total Actual Spending ($)	$ 353,106	96%	$ 353,106	15.5%	15.5%
Cost-effectiveness: Total Resource Cost Test (Ratio)	1.6		1.7		
Cost-effectiveness: Program Administrator Cost Test (Ratio)	2.0		2.2		
Cost-effectiveness: Levelized Unit Electricity Cost ($/kWh)	0.03		0.03		

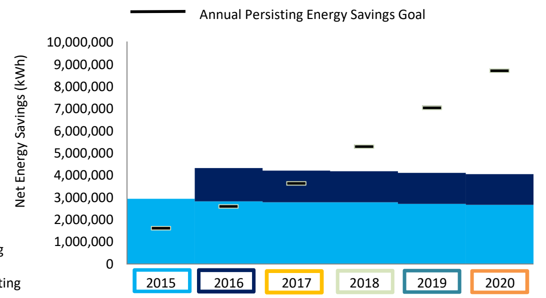
LDC Ranking in the Province out of 73

	6-year CDM Total Cost Effectiveness (PAC)	Total % of 6-year Allocated Budget Spent	Total % of 6-year Allocated Target
This Month:	52	10	8
Last Month:	60	10	7

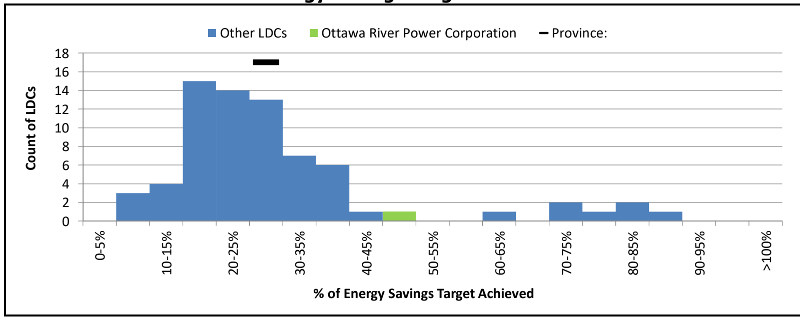
2016 % Contribution by Program



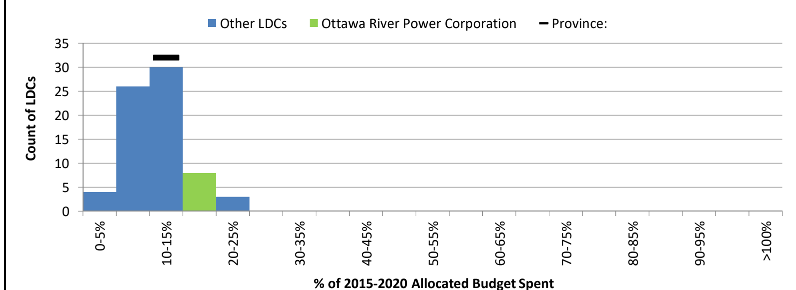
Persisting Energy Savings by Year



% of 2015-2020 Allocated Energy Savings Target Achieved



% of 2015-2020 Allocated Budget Spent



Ottawa River Power Corporation

As of: 31-Dec-16

	Program	2016 CDM Plan Forecast % kWh Target	2016 CDM Plan Forecast % Budget Spent	6-year CDM Plan Forecast % kWh Target	6-year CDM Plan Forecast % Budget Spent
Residential (Province-Wide)	Save on Energy Coupon Program	247%	100%	46.2%	19.1%
	Save on Energy Heating and Cooling Program	361%	86%	132.4%	19.5%
	Save on Energy New Construction Program	0%	3%	0.0%	0.6%
	Save on Energy Home Assistance Program	0%	5%	0.0%	1.2%
	Residential Programs Total	**253%**	**72%**	**52.5%**	**15.3%**
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program		5%	0.0%	0.6%
	Save on Energy Retrofit Program	161%	165%	33.6%	32.3%
	Save on Energy Retrofit Program - P4P				
	Save on Energy Small Business Lighting Program	52%	20%	9.9%	5.6%
	Save on Energy High Performance New Construction Program		3%	0.0%	0.3%
	Save on Energy Existing Building Commissioning Program				0.0%
	Save on Energy Process & Systems Upgrades Program				-5795.0%
	Save on Energy Process & Systems Upgrades Program - P4P				
	Save on Energy Monitoring & Targeting Program				0.0%
	Save on Energy Energy Manager Program				0.0%
	Non-Residential Programs Total	**139%**	**105%**	**28.7%**	**22.5%**
Local LDC Programs	**Local LDC Programs Total**				
Central Services	**LDC Innovation Pilots Total**				
	Provincial Energy Manager Program				
Target Gap					
Non-Approved Program					
Unassigned Program					
Energy Savings from 2011-2014 Framework				**176%**	
TOTAL Conservation First (CDM Plan Forecast)		**151%**	**96%**	**49.3%**	**15.5%**
TOTAL Conservation First (Target and Budget Allocation)				**49.3%**	**15.5%**

Count (Incremental) >
Energy Savings (Incremental) >
Energy Savings (Persisiting to 2020) >
Spending (Year to Date) >
Spending (Program to Date) >
Cost Effectiveness (Year to Date) >
Cost Effectiveness (Program to Date) >

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Province-Wide Progress

As of: 31-Dec-16

	Program	2016 CDM Plan Forecast % kWh Target	2016 CDM Plan Forecast % Budget Spent	6-year CDM Plan Forecast % kWh Target	6-year CDM Plan Forecast % Budget Spent
Residential (Province-Wide)	Save on Energy Coupon Program	162%	137%	52.6%	41.5%
	Save on Energy Heating and Cooling Program	99%	106%	29.8%	31.9%
	Save on Energy New Construction Program	25%	51%	6.1%	10.5%
	Save on Energy Home Assistance Program	90%	69%	22.5%	15.8%
	Residential Programs Total	**139%**	**109%**	**42.7%**	**31.1%**
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program	19%	44%	0.0%	9.5%
	Save on Energy Retrofit Program	51%	70%	16.9%	17.6%
	Save on Energy Retrofit Program - P4P	0%	6%	1.8%	1.3%
	Save on Energy Small Business Lighting Program	20%	23%	2.3%	4.6%
	Save on Energy High Performance New Construction Program	19%	29%	6.2%	9.8%
	Save on Energy Existing Building Commissioning Program	18%	51%	0.0%	9.5%
	Save on Energy Process & Systems Upgrades Program	13%	19%	2.1%	3.0%
	Save on Energy Process & Systems Upgrades Program - P4P			0.0%	0.0%
	Save on Energy Monitoring & Targeting Program	0%	7%	0.0%	1.8%
	Save on Energy Energy Manager Program	5%	24%	1.1%	4.9%
	Non-Residential Programs Total	**38%**	**49%**	**10.3%**	**11.2%**
< Local LDC Programs	**Local LDC Programs Total**	**14%**	**64%**	**0.2%**	**8.2%**
< Central Services	**LDC Innovation Pilots Total**	**0%**	**0%**	**0.0%**	**0.0%**
	Provincial Energy Manager Program				
	Target Gap				
	Non-Approved Program				
	Unassigned Program				
	Energy Savings from 2011-2014 Framework			**116%**	
<	**TOTAL Conservation First (CDM Plan Forecast)**	**48%**	**63%**	**27.4%**	**12.6%**
	TOTAL Conservation First (Target and Budget Allocation)			**27.5%**	**12.6%**

Count (Incremental) >
Energy Savings (Incremental) >
Energy Savings (Persisiting to 2020) >
Spending (Year to Date) >
Spending (Program to Date) >
Cost Effectiveness (Year to Date) >
Cost Effectiveness (Program to Date) >

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Program Participation & Cost Report
IESO Value Added Services Costs

Ottawa River Power Corporation

Unless otherwise stated, all values are unverified

		Activity	Measures Installed	Net Incremental Energy Savings (kWh)	Administrative Expenses (Variable)	Participant Incentives	Total Value Added Services Spending
Provincial Actuals for the period	2015 Verified Coupon Program (VAS & LDC)	Measures	1,207,534	31,459,586.5	$ 1,374,844	$ 3,845,994	$ 5,220,838
	Coupon Program - Allocated	Measures	1,958,297	39,784,595.4	$ 659,145	$ 5,064,669	$ 5,723,814
	Coupon Program - LDC Coded	Measures	914,398	12,227,001.6	$ 224,711	$ 2,244,310	$ 2,469,021
	Coupon Program - Bi-Annual Coupons - Allocated	Measures	8,478,826	120,631,911.4	$ 1,974,569	$ 20,582,204	$ 22,556,772
	Coupon Total	Measures	12,559,055	204,103,094.9	$ 4,233,268	$ 31,737,176	$ 35,970,444
	2015 Verified Heating and Cooling Program	Equipment	20,235	10,181,961.4	$ 265,798	$ 6,213,250	$ 6,479,048
	Heating and Cooling Program	Equipment	104,341	36,066,997.7	$ 1,019,096	$ 32,445,500	$ 33,464,596
	Heating and Cooling Program to Date Total	Equipment	124,576	46,248,959.1	$ 1,284,894	$ 38,658,750	$ 39,943,644
	LDC Value Added Services Provincial Total			**250,352,054.1**	**$ 5,518,162**	**$ 70,395,926**	**$ 75,914,088**
LDC Actuals for the period	2015 Verified Coupon Program (VAS & LDC)	Measures	-	0.0	$ -	$ -	$ -
	Coupon Program - Allocated	Measures	2,731	55,745.8	$ 770	$ 7,006	$ 7,775
	Coupon Program - LDC Coded	Measures	2	25.0	$ 1	$ 3	$ 4
	Coupon Program - Bi-Annual Coupons - Allocated	Measures	10,369	149,696.6	$ 2,398	$ 25,157	$ 27,555
	Coupon Total	Measures	13,102	205,467.5	$ 3,168	$ 32,166	$ 35,334
	2015 Verified Heating and Cooling Program	Equipment	-	0.0	$ -	$ -	$ -
	Heating and Cooling Program	Equipment	104	64,888.1	$ 1,131	$ 30,200	$ 31,331
	Heating and Cooling Program to Date Total	Equipment	104	64,888.1	$ 1,131	$ 30,200	$ 31,331
	LDC Value Added Services LDC Total			**270,355.5**	**$ 4,299**	**$ 62,366**	**$ 66,665**

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Program Participation & Cost Report
Methodology

General

All results are at the end-user level (not including transmission and distribution losses).

Savings Calculations

#	Project Type	Equations
1	Prescriptive Measures and Projects Programs	Gross Reported Savings = Activity * Per Unit Assumption Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
2	Engineered and Custom Projects / Programs	Gross Reported Savings = Reported Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
3	Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the annual effect of energy savings.

2011-2014+2015 Extension Legacy Framework Initiatives

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
1	saveONenergy Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	saveONenergy Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.	
3	saveONenergy Appliance Retirement	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	Savings are considered to begin in the year the appliance is picked up.	
4	saveONenergy HVAC Incentives	Results directly attributed to LDC based on customer applications and postal code.	Savings are considered to begin in the year that the installation occurred.	
5	saveONenergy Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system.	Savings are considered to begin in the year of the project completion date.	
6	saveONenergy Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
7	saveONenergy Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
		Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)		
9	saveONenergy Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
10	saveONenergy New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.		Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
11	saveONenergy Existing Building Commissioning Incentive			
12	saveONenergy Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
13	saveONenergy Monitoring & Targeting			
14	saveONenergy Energy Manager		Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	
14	saveONenergy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
15	Aboriginal Conservation Program			

2015-2020 Conservation First Framework Programs

#	Program	Attributing Savings to LDCs	Savings 'Start' Date	Calculating Resource Savings
1	Save on Energy Coupon Program	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Save on Energy Heating and Cooling Program	Results directly attributed to LDC based on customer applications and postal code. LDCs may see additional participation, savings and spending relative to the March 2016 Value Added Services Report due to previously unassigned applications completed in 2015. Adjustments to reflect final 2015 verified participation will appear in your July 2016 Value Added Services Report to be issued on August 15, 2016	Savings are considered to begin in the year that the installation occurred.	
3	Save on Energy New Construction Program	Results are directly attributed to LDC based on LDC identified in CDM LDC Report Template.	Savings are considered to begin in the year of the project completion date.	
4	Save on Energy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	
5	Save on Energy Audit Funding Program	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
6	Save on Energy Retrofit Program	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date as reported in the CDM LDC Report Template	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
7	Save on Energy Small Business Lighting Program	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
8	Save on Energy High Performance New Construction Program	Results are directly attributed to LDC based on LDC identified in the application.		Peak demand and energy savings are determined by the total savings for a given project as reported in the CDM LDC Report Template. Preliminary unverified net savings are calculated by multiplying reported savings by 2014 Net to-gross ratios and realization rates.
9	Save on Energy Existing Building Commissioning Program			
10	Save on Energy Process and Systems Upgrades Program	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the project was in-service.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
11	Save on Energy Monitoring and Targeting Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011, 2012 or 2013.	Savings are considered to begin in the year in which the incentive project was completed.	
12	Save on Energy Energy Manager Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	
13	Business Refrigeration Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
14	Social Benchmarking Program		Savings are considered to begin in the year in which the report was sent.	Peak demand and energy savings are determined using the verified measure level (home) per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level (home).
15	First Nations Conservation Program		Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

IESO Value Added Services Costs

1) IESO Value Added Services Costs are based on activity reported as of March 31, 2016.

2) Save on Energy Heating & Cooling Program activity may be greater than the March 2016 IESO Value Added Services Report due to previously unassigned applications being assigned to LDCs through the Evaluation, Measurement & Verification Process based on updated applicant postal code mappings. These additional applications and costs will be reflected in the July 2016 IESO Value Added Services Report.

3) Future years may include adjustments to prior years based on delays of Value-Added Service report submissions to IESO from IESO Value-Added Service providers.

4) IESO Value Added Services costs are calculated based on the prevailing IESO Value Added Services Rates as per the applicable IESO Central Services Strategy and Rate Guideline.

Program Participation & Cost Report
Consumer Program Allocation Methodology

#	Local Distribution Company	Allocation
1	Algoma Power Inc.	0.2207%
2	Atikokan Hydro Inc.	0.0265%
3	Attawapiskat Power Corporation	0.0255%
4	Bluewater Power Distribution Corporation	0.6460%
5	Brant County Power Inc.	0.1979%
6	Brantford Power Inc.	0.7255%
7	Burlington Hydro Inc.	1.3757%
8	Cambridge and North Dumfries Hydro Inc.	0.9578%
9	Canadian Niagara Power Inc.	0.5110%
10	Centre Wellington Hydro Ltd.	0.1129%
11	Chapleau Public Utilities Corporation	0.0379%
12	COLLUS PowerStream Corp.	0.2858%
13	Cooperative Hydro Embrun Inc.	0.0494%
14	E.L.K. Energy Inc.	0.2270%
15	Enersource Hydro Mississauga Inc.	3.9265%
16	Entegrus Powerlines Inc.	0.7226%
17	EnWin Utilities Ltd.	1.5542%
18	Erie Thames Powerlines Corporation	0.3535%
19	Espanola Regional Hydro Distribution Corporation	0.0821%
20	Essex Powerlines Corporation	0.6539%
21	Festival Hydro Inc.	0.3498%
22	Fort Albany Power Corporation	0.0212%
23	Fort Frances Power Corporation	0.0995%

24	Greater Sudbury Hydro Inc.	1.0276%
25	Grimsby Power Incorporated	0.2279%
26	Guelph Hydro Electric Systems Inc.	0.8983%
27	Haldimand County Hydro Inc.	0.4244%
28	Halton Hills Hydro Inc.	0.5475%
29	Hearst Power Distribution Company Limited	0.0667%
30	Horizon Utilities Corporation	4.0429%
31	Hydro 2000 Inc.	0.0390%
32	Hydro Hawkesbury Inc.	0.1394%
33	Hydro One Brampton Networks Inc.	2.8180%
34	Hydro One Networks Inc.	29.9788%
35	Hydro Ottawa Limited	5.5954%
36	InnPower Corporation	0.3951%
37	Kashechewan Power Corporation	0.0286%
38	Kenora Hydro Electric Corporation Ltd.	0.0989%
39	Kingston Hydro Corporation	0.5014%
40	Kitchener-Wilmot Hydro Inc.	1.6310%
41	Lakefront Utilities Inc.	0.1907%
42	Lakeland Power Distribution Ltd.	0.2906%
43	London Hydro Inc.	2.7308%
44	Midland Power Utility Corporation	0.1196%
45	Milton Hydro Distribution Inc.	0.5695%
46	Newmarket-Tay Power Distribution Ltd.	0.6607%
47	Niagara Peninsula Energy Inc.	0.9945%
48	Niagara-on-the-Lake Hydro Inc.	0.1586%
49	Norfolk Power Distribution Inc.	0.3495%
50	North Bay Hydro Distribution Limited	0.5333%
51	Northern Ontario Wires Inc.	0.1061%
52	Oakville Hydro Electricity Distribution Inc.	1.4632%

53	Orangeville Hydro Limited	0.2120%
54	Orillia Power Distribution Corporation	0.2722%
55	Oshawa PUC Networks Inc.	1.2283%
56	Ottawa River Power Corporation	0.1974%
57	Peterborough Distribution Incorporated	0.7132%
58	PowerStream Inc.	6.6383%
59	PUC Distribution Inc.	0.8687%
60	Renfrew Hydro Inc.	0.0775%
61	Rideau St. Lawrence Distribution Inc.	0.1120%
62	Sioux Lookout Hydro Inc.	0.0841%
63	St. Thomas Energy Inc.	0.2939%
64	Thunder Bay Hydro Electricity Distribution Inc.	0.8738%
65	Tillsonburg Hydro Inc.	0.1280%
66	Toronto Hydro-Electric System Limited	12.7979%
67	Veridian Connections Inc.	2.3525%
68	Wasaga Distribution Inc.	0.1799%
69	Waterloo North Hydro Inc.	1.0019%
70	Welland Hydro-Electric System Corp.	0.3879%
71	Wellington North Power Inc.	0.0632%
72	West Coast Huron Energy Inc.	0.0653%
73	Westario Power Inc.	0.5411%
74	Whitby Hydro Electric Corporation	0.8651%
75	Woodstock Hydro Services Inc.	0.2548%
Total		**100.0000%**

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Program Participation & Cost Report
Glossary

#	Term	Definition
1	2011-2014+2015 Extension Legacy Framework Programs	Programs in market from 2011-2015 resulting from the April 23, 2010 GEA CDM Ministerial Directive and funded separately from 2015-2020 Conservation First Framework Programs but whose savings in 2015 are attributed towards the 2015-2020 Conservation First Framework target.
2	2015-2020 Conservation First Framework Programs	Programs in market from 2015-2020 resulting from the March 31, 2014 CFF Ministerial Directive and funded separately from 2011-2014+2015 Extension Legacy Framework Programs.
3	Allocated Target	Each LDC's assigned portion of the Province's 7 TWh Net 2020 Annual Energy Savings Target of the 2015-2020 Conservation First Framework.
4	Allocated Budget	Each LDC's assigned portion of the Province's $ 1.835 billion CDM Plan Budget of the 2015-2020 Conservation First Framework.
5	Province-Wide Program	Programs available to all LDCs to deliver and that are consistent across the province.
6	Regional Program	Programs designed by LDCs to serve their region and approved by the IESO.
7	Local Program	Programs designed by LDCs to serve their communities and approved by the IESO.
8	Pilot Program	A program pilot that may achieve energy or demand savings and is funded extraneous to an LDC's CDM Plan Budget.
9	Initiative	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup) from the 2011-2014+2015 Extension Legacy Framework.
10	Program	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup) from the 2015-2020 Conservation First Framework.

11	Activity	The number of projects.
12	Unit	For a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).
13	Forecast	LDC's forecast of activity, savings, expenditures and cost effectiveness as indicated in each LDC's submitted CDM Plan Cost Effectiveness Tools.
14	Actual	The IESO determined final results of activity, savings, expenditures and cost effectiveness.
15	Progress	A comparison of Actuals versus Forecasts.
16	Full Cost Recovery Progress	For a given year, the percentage calculated by dividing: a) the sum of verified electricity savings for all years of the term up to and including the applicable year for all Programs that receive full cost recovery funding, by b) the Cumulative FCR Milestone, multiplied by 100%, as specified in Schedule A of the Energy Conservation Agreement.
17	Reported Savings	Savings determined by the LDC: 1) for prescriptive projects/programs: calculating quantity x prescriptive savings assumptions; and 2) for engineered or custom program projects/programs: calculated using prescribed methodologies.
18	Verified Savings	Savings determined by the IESO's evaluation, measurement and verification that may adjust reported savings by the realization rate.
19	Gross Savings	Savings determined as either: 1) program activity multiplied by per unit savings assumptions for prescriptive programs; or 2) reported savings multiplied by the realization rate for engineered or custom program streams.
20	Net Savings	The peak demand or energy savings attributable to conservation and demand management activities net of free-riders, etc.
21	Realization Rate	A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.
22	Net-to-Gross Adjustment	The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover.
23	Free-ridership	The percentage of participants who would have implemented the program measure or practice in the absence of the program.

24	Spillover	Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.
25	Incremental Savings	The new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.
26	First Year Savings	The peak demand or energy savings that occur in the year it was achieved (includes resource savings from only new program activity).
27	Annual Savings	The peak demand or energy savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).
28	Demand Savings	Demand savings attributable to conservation and demand management activities.
29	Energy Savings	Energy savings attributable to conservation and demand management activities.
30	Administrative Expenses	Costs incurred in the delivery of a program related to labour, marketing, third-party expenses, value added services or other central services.
31	Participant Incentives	Costs incurred in the delivery of a program related to incenting participants to perform peak demand or energy savings.
32	Total Expenditure	The sum of Administrative Expenses and Participant Incentives
33	Total Resource Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on the total costs of the program including both participants' and utility's costs.
34	Program Administrator Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on costs incurred by the program administrator, including incentive costs and excluding net costs incurred by the participant.
35	Levelized Unit Energy Cost Cost Effectiveness Test	A cost effectiveness test that normalizes the costs incurred by the program administrator per unit of energy or demand reduced.

Program Participation & Cost Report
Message from the IESO Reporting Team

The IESO is pleased to provide LDCs with the Monthly Program Participation & Cost Report.

This report is generally posted on the IESO LDC Extranet by the Friday of the week following the 15th of each month. The report provides province-wide and LDC specific program participation and costs to the extent known based on information received by the IESO from all distribution companies and IESO Value Added Service Provider.

The Monthly Program Participation & Cost Report includes preliminary, unverified results based on information received by the IESO. Upon verification of project information through the IESO Evaluation, Measurement and Verification (EM&V) process, results will be reported as 'verified'. Performance against CDM Plan information is also available in this report and is based on the LDC's approved CDM Plan as at the end of the reporting period. Where two or more LDCs have submitted a joint CDM Plan, the IESO will provide a Monthly Program Participation & Cost Report for each LDC included in the CDM Plan.

The IESO strives to improve on the current reporting processes to provide meaningful and timely information to LDCs. Your feedback is encouraged and appreciated. Should you have any feedback, questions or comments on this report please contact us at LDC.Support@ieso.ca.

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Program Participation & Cost Report
Table of Contents

Program Participation & Cost Report
How to Use This Report

The IESO is pleased to provide you with the Monthly Participation and Cost Report.

This report provides:
1) program participation;
1) electricity savings; and
2) costs
to the extent known based on information received by the IESO in accordance with Section 9.2(c)(i) of the Energy Conservation Agreement.

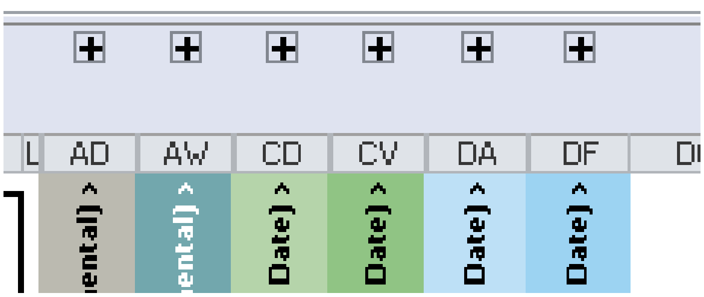
In addition to the above, this report also provides in greater detail:
1) program participation results including:
   a) forecasts; b) actuals; and c) progress (forecast versus (vs) actuals);

2) program savings results including:
   a) net 2020 annual energy savings;
   b) allocated target, target achievement and progress towards target;
   c) incremental net first year energy savings;
   and where available reported by: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

3) program spending including:
   a) participation incentive spending;
   b) administrative expense spending (including IESO value-added services costs);
   c) aggregated total spending;
   and for each cost: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

by both the LDC specific level and the province-wide aggregated level.

This report's format is a dynamic sheet that can be expanded or collapsed by clicking the + button or "Show Detail" feature under the Data tab. Each of the results categories listed above have been grouped together for easy accessibility.



Please note:
1) Cost Effectiveness Test (CET) results including:
   a) total resource cost test;
   b) program administration cost test;
   c) levelized unit energy cost test;
   will not be available for the 2015 program year in this report but will be provided to LDCs once available.

2) forecasts of: a) activity; b) savings; and c) spending; included in this report are
   based on LDC submitted and IESO approved CDM Plan - Cost Effectiveness Tools as of the end of the reporting month.
   (from the i) Program Design; ii) Budget Inputs; iii) Savings Results; and iv) CE Results; worksheets);
   Please note that this does not contain data for Legacy Framework program spending or CFF pilot program activity, savings, spending or cost effectiveness.

3) Annual FCR Progress only includes Full Cost Recovery funded program savings. In future reports, any Pay-for-Performance funded programs will be reported as a separate line item.

4) The complete list of programs and pilots launched into market in 2015 has been included, however no programs and pilots were in market for a sufficient period of time to enable a valid EM&V process. Therefore these programs and pilots have nothing to report at this time and have cells greyed out rather than reporting zero savings or spending. Any results in 2015 will be determined in a subsequent EM&V process and will be included in a future year's Annual Verified Results Report as a 2015 adjustment;

5) Pilot program savings are attributed to the LDC where the pilot program project is located in; and

6) This Monthly Participation and Cost Report provides results for the LDC and province only. No aggregated reporting is provided for LDCs that are part of a joint CDM plan;

Program Participation & Cost Report
Summary

	CDM Plan	vs	Allocated	Paid Pre-Funding
CFF Target (kWh):	8,720,045		8,719,912	
CFF Budget:	$1,989,075		$2,282,373	$91,531

Ottawa River Power Corporation
As of: 31-Dec-17

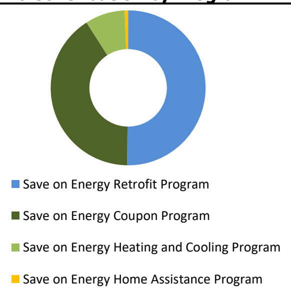
Summary of Performance Metrics

	2017 CDM Results	2017 CDM Plan %	6-year CDM Results	6-year CDM Plan %	6-year Allocated %
Net Energy Savings (kWh) as at 2020	1,063,396	70%	6,163,638	70.7%	70.7%
Total Actual Spending ($)	$ 541,200	116%	$ 925,637	46.5%	40.6%
Cost-effectiveness: Total Resource Cost Test (Ratio)	0.7		1.6		
Cost-effectiveness: Program Administrator Cost Test (Ratio)	1.1		2.0		
Cost-effectiveness: Levelized Unit Electricity Cost ($/kWh)	0.06		0.03		

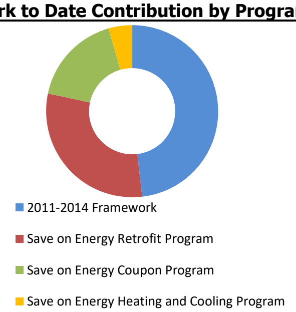
LDC Ranking in the Province out of 68

	6-year CDM Total Cost Effectiveness (PAC)	Total % of 6-year Allocated Budget Spent	Total % of 6-year Allocated Target
This Month:	26	17	13
Last Month:	12	14	12

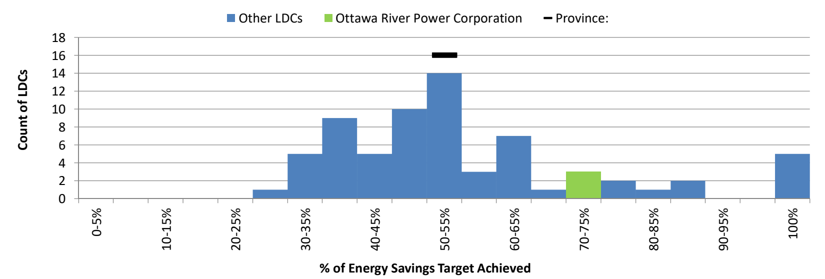
2017 % Contribution by Program



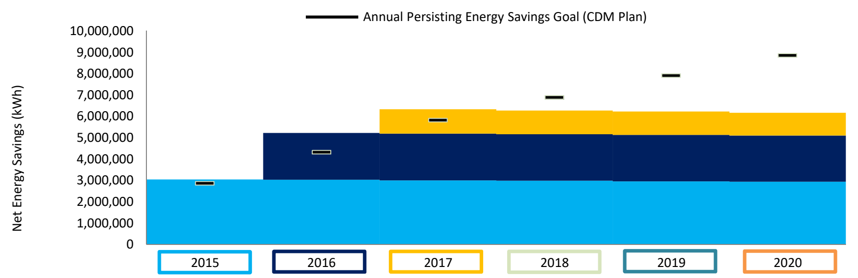
Framework to Date Contribution by Program



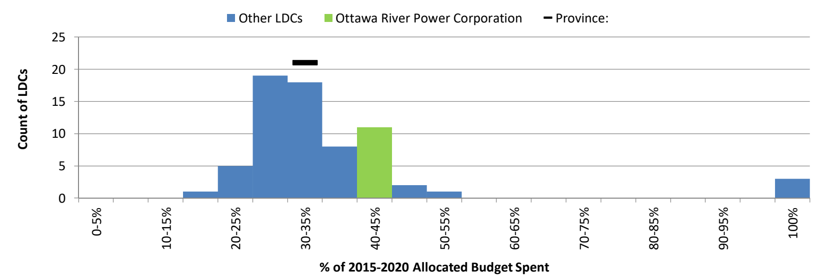
% of 2015-2020 Allocated Energy Savings Target Achieved



Persisting Energy Savings by Year



% of 2015-2020 Allocated Budget Spent



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Ottawa River Power Corporation

As of: 31-Dec-17

	Program	2017 CDM Plan Forecast: % kWh Target	2017 CDM Plan Forecast: % Budget Spent	6-year CDM Plan Forecast: % kWh Target	6-year CDM Plan Forecast: % Budget Spent
Residential (Province-Wide)	Save on Energy Coupon Program	242%	352%	152.1%	111.1%
	Save on Energy Heating and Cooling Program	1008%	191%	275.8%	80.9%
	Instant Discount Program				
	Save on Energy New Construction Program	0%	32%		18.9%
	Save on Energy Home Assistance Program	131%	431%	56.5%	106.4%
	Residential Programs Total	**271%**	**293%**	**164.4%**	**95.9%**
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program	0%	1%	0.0%	2.0%
	Save on Energy Retrofit Program	44%	76%	41.3%	36.5%
	Save on Energy Retrofit Program - P4P				
	Save on Energy Retrofit Program Enabled Savings				
	Save on Energy Small Business Lighting Program	113%	224%	40.8%	59.9%
	Business Refrigeration Program	0%	0%	0.0%	0.0%
	Save on Energy Existing Building Commissioning Program	0%	0%		0.0%
	Save on Energy High Performance New Construction Program	0%	0%	0.0%	1.2%
	Save on Energy Process & Systems Upgrades Program	0%	8342%		3534.3%
	Save on Energy Process & Systems Upgrades Program - P4P				
	Save on Energy Process & Systems Upgrades Program Enabled Saving				
	Save on Energy Energy Manager Program	0%	0%		0.0%
	Save on Energy Monitoring & Targeting Program	0%	0%		0.0%
	Non-Residential Programs Total	**50%**	**86%**	**43.9%**	**37.6%**
< Local LDC Programs	**Local LDC Programs Total**				
< Central Services	**LDC Innovation Pilots Total**				
	Provincial Energy Manager Program				
Target Gap					
Non-Approved Program					
Unassigned Program					
Energy Savings from 2011-2014 Framework				**103%**	
< **TOTAL Conservation First (CDM Plan Forecast)**		**70%**	**116%**	**70.7%**	**46.5%**
TOTAL Conservation First (Target and Budget Allocation)				**70.7%**	**40.6%**

Count (Incremental) >	Energy Savings (Incremental) >	Energy Savings (Persisting to 2020) >	Spending (Year to Date) >	Spending (Program to Date) >	Cost Effectiveness (Year to Date) >	Cost Effectiveness (Program to Date) >

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Province-Wide Progress

As of: 31-Dec-17

	Program	2017 CDM Plan Forecast: % kWh Target	2017 CDM Plan Forecast: % Budget Spent	6-year CDM Plan Forecast: % kWh Target	6-year CDM Plan Forecast: % Budget Spent
Residential (Province-Wide)	Save on Energy Coupon Program	251%	289%	138.6%	108.5%
	Save on Energy Heating and Cooling Program	89%	129%	90.8%	77.4%
	Instant Discount Program				
	Save on Energy New Construction Program	30%	105%	14.4%	30.0%
	Save on Energy Home Assistance Program	118%	92%	45.6%	32.7%
	Residential Programs Total	**195%**	**189%**	**117.0%**	**79.2%**
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program	34%	121%	14.2%	38.3%
	Save on Energy Retrofit Program	52%	91%	44.2%	38.7%
	Save on Energy Retrofit Program - P4P	0%	53%	14.5%	8.1%
	Save on Energy Retrofit Program Enabled Savings				
	Save on Energy Small Business Lighting Program	42%	69%	16.9%	24.2%
	Business Refrigeration Program	61%	74%	18.8%	20.7%
	Save on Energy Existing Building Commissioning Program	0%	41%	0.0%	21.3%
	Save on Energy High Performance New Construction Program	19%	99%	25.9%	30.9%
	Save on Energy Process & Systems Upgrades Program	7%	29%	1.7%	9.0%
	Save on Energy Process & Systems Upgrades Program - P4P			43.1%	0.3%
	Save on Energy Process & Systems Upgrades Program Enabled Saving				
	Save on Energy Energy Manager Program	48%	69%	25.8%	18.8%
	Save on Energy Monitoring & Targeting Program	0%	29%	2.0%	10.3%
	Non-Residential Programs Total	**46%**	**73%**	**37.2%**	**26.3%**
< Local LDC Programs	**Local LDC Programs Total**	**37%**	**78%**	**17.7%**	**26.2%**
< Central Services	**LDC Innovation Pilots Total**	**0%**		**672.9%**	**103.4%**
	Provincial Energy Manager Program				
Target Gap					
Non-Approved Program					
Unassigned Program					
Energy Savings from 2011-2014 Framework				**123%**	
< **TOTAL Conservation First (CDM Plan Forecast)**		**59%**	**98%**	**52.8%**	**34.4%**
TOTAL Conservation First (Target and Budget Allocation)				**55.0%**	**34.2%**

Count (Incremental) >
Energy Savings (Incremental) >
Energy Savings (Persisiting to 2020) >
Spending (Year to Date) >
Spending (Program to Date) >
Cost Effectiveness (Year to Date) >
Cost Effectiveness (Program to Date) >

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Program Participation & Cost Report
IESO Value Added Services Costs

Ottawa River Power Corporation

*Allocated Coupons includes Instant Discounts - For breakout please see Value Added Services Report

Unless otherwise stated, all values are unverified

Year end adjustments for invalid coupons that didn't align with retailer sales data are done in the Decembers IESO reporting period.

		Activity	Measures Installed	Net Incremental Energy Savings (kWh)	Administrative Expenses (Variable)	Participant Incentives	Total Value Added Services Spending	
Provincial Actuals for the period	Verified Coupon Program (VAS & LDC)	Measures	18,260,821	463,980,654.8	$ 4,233,268	$ 31,727,255	$ 35,960,523	
	Coupon Program - Allocated	Measures	10,721,549	135,672,063.7	$ 1,364,415	$ 21,939,675	$ 23,304,090	*
	Coupon Program - LDC Coded	Measures	1,880,374	23,192,702.2	$ 499,045	$ 6,044,146	$ 6,543,191	
	Coupon Program - Bi-Annual Coupons - Allocated	Measures	15,870,386	205,390,979.4	$ 5,019,222	$ 55,181,103	$ 60,200,326	
	Coupon Total	Measures	46,733,130	828,236,400.1	$ 11,115,950	$ 114,892,180	$ 126,008,129	
	Verified Heating and Cooling Program	Equipment	156,852	87,816,036.1	$ 1,284,894	$ 37,754,200	$ 39,039,094	
	Heating and Cooling Program	Equipment	228,640	113,926,811.7	$ 1,334,809	$ 38,242,200	$ 39,577,009	
	Heating and Cooling Program to Date Total	Equipment	385,492	201,742,847.8	$ 2,619,703	$ 75,996,400	$ 78,616,103	
	LDC Value Added Services Provincial Total			**1,029,979,248.0**	**$ 13,735,653**	**$ 190,888,580**	**$ 204,624,232**	
LDC Actuals for the period	Verified Coupon Program (VAS & LDC)	Measures	19,693	608,470.9	$ 3,168	$ 32,166	$ 35,334	
	Coupon Program - Allocated	Measures	13,137	166,958.9	$ 1,672	$ 26,885	$ 28,557	*
	Coupon Program - LDC Coded	Measures	-	0.0	$ -	$ -	$ -	
	Coupon Program - Bi-Annual Coupons - Allocated	Measures	19,444	255,608.1	$ 6,149	$ 67,605	$ 73,755	
	Coupon Total	Measures	52,274	1,031,037.9	$ 10,989	$ 126,656	$ 137,645	
	Verified Heating and Cooling Program	Equipment	144	97,877.0	$ 1,131	$ 30,200	$ 31,331	
	Heating and Cooling Program	Equipment	282	166,685.7	$ 2,138	$ 51,350	$ 53,488	
	Heating and Cooling Program to Date Total	Equipment	426	264,562.7	$ 3,269	$ 81,550	$ 84,819	
	LDC Value Added Services LDC Total			**1,295,600.6**	**$ 14,258**	**$ 208,206**	**$ 222,464**	

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Program Participation & Cost Report
Save on Energy Retrofit Program - Multi-Site Applications

Ottawa River Power Corporation

As of: 31-Dec-17

	Program	Count (Incremental) >	Energy Savings (Incremental) >	Energy Savings (Persisiting to 2020) >	2017 Incentive Budget	2017 Year to Date Incentive Actual	2017 Admin Budget	2017 Year to Date Admin Actual	2017 Total Budget	2017 Year to Date Total Actual	Spending (Year to Date) >	Spending (Program to Date) >
Provincial Actuals for the Period	Save on Energy Retrofit Program				$ 72,167,596	$ 81,242,263	$ 35,810,696	$ 40,967,396	$ 134,966,507	$ 122,209,659		
	Multi-Site Applications				-	$ 2,889,481	-	$ 594,512	-	$ 3,483,994		
LDC Actuals for the Period	Save on Energy Retrofit Program				$ 191,629	$ 164,206	$ 122,330	$ 74,066	$ 313,959	$ 238,272		
	Multi-Site Applications				-	$ 1,804	-	$ 525	-	$ 2,329		

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Program Participation & Cost Report
Methodology

General

All results are at the end-user level (not including transmission and distribution losses).

Savings Calculations

#	Project Type	Equations
1	Prescriptive Measures and Projects Programs	Gross Reported Savings = Activity * Per Unit Assumption Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
2	Engineered and Custom Projects / Programs	Gross Reported Savings = Reported Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
3	Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the annual effect of energy savings.

2011-2014+2015 Extension Legacy Framework Initiatives

<table>
<tr><th>#</th><th>Initiative</th><th>Attributing Savings to LDCs</th><th>Savings 'start' Date</th><th>Calculating Resource Savings</th><th>Project Count</th></tr>
<tr><td>1</td><td>saveONenergy
Conservation Instant Coupon Booklet</td><td>LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.</td><td>Savings are considered to begin in the year in which the coupon was redeemed.</td><td rowspan="5">Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.</td><td rowspan="19">Based on project completion date. Count is based of the unit of measurement shown beside the program name. Eg Retrofit is the count of Projects.</td></tr>
<tr><td>2</td><td>saveONenergy
Bi-Annual Retailer Event</td><td>Results are allocated based on average of 2008 & 2009 residential throughput.</td><td>Savings are considered to begin in the year in which the event occurs.</td></tr>
<tr><td>3</td><td>saveONenergy
Appliance Retirement</td><td>Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.</td><td>Savings are considered to begin in the year the appliance is picked up.</td></tr>
<tr><td>4</td><td>saveONenergy
HVAC Incentives</td><td>Results directly attributed to LDC based on customer applications and postal code.</td><td>Savings are considered to begin in the year that the installation occurred.</td></tr>
<tr><td>5</td><td>saveONenergy
Residential New Construction</td><td>Results are directly attributed to LDC based on LDC identified in application in the iCon system.</td><td>Savings are considered to begin in the year of the project completion date.</td></tr>
<tr><td>6</td><td>saveONenergy
Energy Audit</td><td>Projects are directly attributed to LDC based on LDC identified in the application.</td><td>Savings are considered to begin in the year of the audit date.</td><td>Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).</td></tr>
<tr><td rowspan="2">7</td><td rowspan="2">saveONenergy
Efficiency: Equipment Replacement</td><td>Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system.

Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.</td><td>Savings are considered to begin in the year of the actual project completion date in the iCON system.</td><td>Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).</td></tr>
<tr><td colspan="3">Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)</td></tr>
<tr><td>9</td><td>saveONenergy
Direct Installed Lighting</td><td>Results are directly attributed to LDC based on the LDC specified on the work order.</td><td rowspan="3">Savings are considered to begin in the year of the actual project completion date.</td><td>Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).</td></tr>
<tr><td>10</td><td>saveONenergy
New Construction and Major Renovation Incentive</td><td rowspan="2">Results are directly attributed to LDC based on LDC identified in the application.</td><td rowspan="2">Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).</td></tr>
<tr><td>11</td><td>saveONenergy
Existing Building Commissioning Incentive</td></tr>
<tr><td>12</td><td>saveONenergy
Process & System Upgrades</td><td rowspan="3">Results are directly attributed to LDC based on LDC identified in application.</td><td rowspan="2">Savings are considered to begin in the year in which the incentive project was completed.</td><td rowspan="3">Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).</td></tr>
<tr><td>13</td><td>saveONenergy
Monitoring & Targeting</td></tr>
<tr><td>14</td><td>saveONenergy
Energy Manager</td><td>Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.</td></tr>
<tr><td>14</td><td>saveONenergy
Home Assistance Program</td><td rowspan="2">Results are directly attributed to LDC based on LDC identified in the application.</td><td rowspan="2">Savings are considered to begin in the year in which the measures were installed.</td><td rowspan="2">Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.</td></tr>
<tr><td>15</td><td>Aboriginal Conservation Program</td></tr>
</table>

2015-2020 Conservation First Framework Programs

#	Program	Attributing Savings to LDCs	Savings 'Start' Date	Calculating Resource Savings	Project Count
1	Save on Energy Coupon Program	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
2	Save on Energy Heating and Cooling Program	Results directly attributed to LDC based on customer applications and postal code. LDCs may see additional participation, savings and spending relative to the March 2016 Value Added Services Report due to previously unassigned applications completed in 2015. Adjustments to reflect final 2015 verified participation will appear in your July 2016 Value Added Services Report to be issued on August 15, 2016	Savings are considered to begin in the year that the installation occurred.		
3	Save on Energy New Construction Program	Results are directly attributed to LDC based on LDC identified in CDM LDC Report Template.	Savings are considered to begin in the year of the project completion date.		
4	Save on Energy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.		
5	Save on Energy Audit Funding Program	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
6	Save on Energy Retrofit Program	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date as reported in the CDM LDC Report Template	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).	
7	Save on Energy Small Business Lighting Program	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date. Count is based off the actual completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	
8	Save on Energy High Performance New Construction Program	Results are directly attributed to LDC based on LDC identified in the application.		Peak demand and energy savings are determined by the total savings for a given project as reported in the CDM LDC Report Template. Preliminary unverified net savings are calculated by multiplying reported savings by 2014 Net-to-gross ratios and realization rates.	Based on project completion date. Could be a future completion date as incentives are paid before the project is completed.
9	Save on Energy Existing Building Commissioning Program				Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
10	Save on Energy Process and Systems Upgrades Program	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the project was in-service.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
11	Save on Energy Monitoring and Targeting Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011, 2012 or 2013.	Savings are considered to begin in the year in which the incentive project was completed.		
12	Save on Energy Energy Manager Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.		Based on project completion date. Could be a future completion date as incentives are paid before the project is completed.
13	Business Refrigeration Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
14	Social Benchmarking Program		Savings are considered to begin in the year in which the report was sent.	Peak demand and energy savings are determined using the verified measure level (home) per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level (home).	
15	First Nations Conservation Program		Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	

IESO Value Added Services Costs

1) IESO Value Added Services Costs are based on activity reported as of March 31, 2016.

2) Save on Energy Heating & Cooling Program activity may be greater than the March 2016 IESO Value Added Services Report due to previously unassigned applications being assigned to LDCs through the Evaluation, Measurement & Verification Process based on updated applicant postal code mappings. These additional applications and costs will be reflected in the July 2016 IESO Value Added Services Report.

3) Future years may include adjustments to prior years based on delays of Value-Added Service report submissions to IESO from IESO Value-Added Service providers.

4) IESO Value Added Services costs are calculated based on the prevailing IESO Value Added Services Rates as per the applicable IESO Central Services Strategy and Rate Guideline.

Program Participation & Cost Report
Consumer Program Allocation Methodology

Year	Local Distribution Company	Allocation
2016 03 31 - Current	Algoma Power Inc.	0.1820%
2016 03 31 - Current	Atikokan Hydro Inc.	0.0229%
2016 03 31 - Current	Attawapiskat Power Corporation	0.0149%
2016 03 31 - Current	Bluewater Power Distribution Corporation	0.6152%
2016 03 31 - Current	Brantford Power Inc.	0.6715%
2016 03 31 - Current	Burlington Hydro Inc.	1.3392%
2016 03 31 - Current	Canadian Niagara Power Inc.	0.3472%
2016 03 31 - Current	Centre Wellington Hydro Ltd.	0.1058%
2016 03 31 - Current	Chapleau Public Utilities Corporation	0.0282%
2016 03 31 - Current	COLLUS PowerStream Corp.	0.2546%
2016 03 31 - Current	Cooperative Hydro Embrun Inc.	0.0563%
2016 03 31 - Current	E.L.K. Energy Inc.	0.2455%
2016 03 31 - Current	Energy+ Inc.	1.1217%
2016 03 31 - Current	Enersource Hydro Mississauga Inc.	4.6424%
2016 03 31 - Current	Entegrus Powerlines Inc.	0.7018%
2016 03 31 - Current	EnWin Utilities Ltd.	1.4909%
2016 03 31 - Current	Erie Thames Powerlines Corporation	0.3197%
2016 03 31 - Current	Espanola Regional Hydro Distribution Corporation	0.0637%
2016 03 31 - Current	Essex Powerlines Corporation	0.6061%
2016 03 31 - Current	Festival Hydro Inc.	0.3248%
2016 03 31 - Current	Fort Albany Power Corporation	0.0099%
2016 03 31 - Current	Fort Frances Power Corporation	0.0900%
2016 03 31 - Current	Greater Sudbury Hydro Inc.	0.7993%
2016 03 31 - Current	Grimsby Power Incorporated	0.1813%
2016 03 31 - Current	Guelph Hydro Electric Systems Inc.	0.8531%
2016 03 31 - Current	Halton Hills Hydro Inc.	0.5897%
2016 03 31 - Current	Hearst Power Distribution Company Limited	0.0510%
2016 03 31 - Current	Horizon Utilities Corporation	3.7200%
2016 03 31 - Current	Hydro 2000 Inc.	0.0394%
2016 03 31 - Current	Hydro Hawkesbury Inc.	0.1467%
2016 03 31 - Current	Hydro One Brampton Networks Inc.	3.5920%
2016 03 31 - Current	Hydro One Networks Inc.	27.2865%
2016 03 31 - Current	Hydro Ottawa Limited	6.6052%
2016 03 31 - Current	InnPower Corporation	0.3309%
2016 03 31 - Current	Kashechewan Power Corporation	0.0177%
2016 03 31 - Current	Kenora Hydro Electric Corporation Ltd.	0.0896%
2016 03 31 - Current	Kingston Hydro Corporation	0.2939%
2016 03 31 - Current	Kitchener-Wilmot Hydro Inc.	1.5077%
2016 03 31 - Current	Lakefront Utilities Inc.	0.1128%
2016 03 31 - Current	Lakeland Power Distribution Ltd.	0.2288%
2016 03 31 - Current	London Hydro Inc.	2.6114%
2016 03 31 - Current	Midland Power Utility Corporation	0.1014%
2016 03 31 - Current	Milton Hydro Distribution Inc.	0.6579%
2016 03 31 - Current	Newmarket-Tay Power Distribution Ltd.	0.5977%
2016 03 31 - Current	Niagara Peninsula Energy Inc.	0.8158%
2016 03 31 - Current	Niagara-on-the-Lake Hydro Inc.	0.1304%
2016 03 31 - Current	North Bay Hydro Distribution Limited	0.4153%

2016 03 31 - Current	Northern Ontario Wires Inc.	0.0860%
2016 03 31 - Current	Oakville Hydro Electricity Distribution Inc.	1.5097%
2016 03 31 - Current	Orangeville Hydro Limited	0.2004%
2016 03 31 - Current	Orillia Power Distribution Corporation	0.2220%
2016 03 31 - Current	Oshawa PUC Networks Inc.	1.4845%
2016 03 31 - Current	Ottawa River Power Corporation	0.1225%
2016 03 31 - Current	Peterborough Distribution Incorporated	0.4607%
2016 03 31 - Current	PowerStream Inc.	7.8184%
2016 03 31 - Current	PUC Distribution Inc.	0.6545%
2016 03 31 - Current	Renfrew Hydro Inc.	0.0477%
2016 03 31 - Current	Rideau St. Lawrence Distribution Inc.	0.0670%
2016 03 31 - Current	Sioux Lookout Hydro Inc.	0.0776%
2016 03 31 - Current	St. Thomas Energy Inc.	0.2780%
2016 03 31 - Current	Thunder Bay Hydro Electricity Distribution Inc.	0.8172%
2016 03 31 - Current	Tillsonburg Hydro Inc.	0.1169%
2016 03 31 - Current	Toronto Hydro-Electric System Limited	15.5698%
2016 03 31 - Current	Veridian Connections Inc.	2.3879%
2016 03 31 - Current	Wasaga Distribution Inc.	0.1754%
2016 03 31 - Current	Waterloo North Hydro Inc.	0.9590%
2016 03 31 - Current	Welland Hydro-Electric System Corp.	0.3103%
2016 03 31 - Current	Wellington North Power Inc.	0.0570%
2016 03 31 - Current	West Coast Huron Energy Inc.	0.0585%
2016 03 31 - Current	Westario Power Inc.	0.3654%
2016 03 31 - Current	Whitby Hydro Electric Corporation	1.1240%
2011 - 2016 03 31	Algoma Power Inc.	0.2207%
2011 - 2016 03 31	Atikokan Hydro Inc.	0.0265%
2011 - 2016 03 31	Attawapiskat Power Corporation	0.0255%
2011 - 2016 03 31	Bluewater Power Distribution Corporation	0.6460%
2011 - 2016 03 31	Brant County Power Inc.	0.1979%
2011 - 2016 03 31	Brantford Power Inc.	0.7255%
2011 - 2016 03 31	Burlington Hydro Inc.	1.3757%
2011 - 2016 03 31	Cambridge and North Dumfries Hydro Inc.	0.9578%
2011 - 2016 03 31	Canadian Niagara Power Inc.	0.5110%
2011 - 2016 03 31	Centre Wellington Hydro Ltd.	0.1129%
2011 - 2016 03 31	Chapleau Public Utilities Corporation	0.0379%
2011 - 2016 03 31	COLLUS PowerStream Corp.	0.2858%
2011 - 2016 03 31	Cooperative Hydro Embrun Inc.	0.0494%
2011 - 2016 03 31	E.L.K. Energy Inc.	0.2270%
2011 - 2016 03 31	Enersource Hydro Mississauga Inc.	3.9265%
2011 - 2016 03 31	Entegrus Powerlines Inc.	0.7226%
2011 - 2016 03 31	EnWin Utilities Ltd.	1.5542%
2011 - 2016 03 31	Erie Thames Powerlines Corporation	0.3535%
2011 - 2016 03 31	Espanola Regional Hydro Distribution Corporation	0.0821%
2011 - 2016 03 31	Essex Powerlines Corporation	0.6539%
2011 - 2016 03 31	Festival Hydro Inc.	0.3498%
2011 - 2016 03 31	Fort Albany Power Corporation	0.0212%
2011 - 2016 03 31	Fort Frances Power Corporation	0.0995%
2011 - 2016 03 31	Greater Sudbury Hydro Inc.	1.0276%
2011 - 2016 03 31	Grimsby Power Incorporated	0.2279%
2011 - 2016 03 31	Guelph Hydro Electric Systems Inc.	0.8983%
2011 - 2016 03 31	Haldimand County Hydro Inc.	0.4244%
2011 - 2016 03 31	Halton Hills Hydro Inc.	0.5475%
2011 - 2016 03 31	Hearst Power Distribution Company Limited	0.0667%

2011 - 2016 03 31	Horizon Utilities Corporation	4.0429%
2011 - 2016 03 31	Hydro 2000 Inc.	0.0390%
2011 - 2016 03 31	Hydro Hawkesbury Inc.	0.1394%
2011 - 2016 03 31	Hydro One Brampton Networks Inc.	2.8180%
2011 - 2016 03 31	Hydro One Networks Inc.	29.9788%
2011 - 2016 03 31	Hydro Ottawa Limited	5.5954%
2011 - 2016 03 31	InnPower Corporation	0.3951%
2011 - 2016 03 31	Kashechewan Power Corporation	0.0286%
2011 - 2016 03 31	Kenora Hydro Electric Corporation Ltd.	0.0989%
2011 - 2016 03 31	Kingston Hydro Corporation	0.5014%
2011 - 2016 03 31	Kitchener-Wilmot Hydro Inc.	1.6310%
2011 - 2016 03 31	Lakefront Utilities Inc.	0.1907%
2011 - 2016 03 31	Lakeland Power Distribution Ltd.	0.2906%
2011 - 2016 03 31	London Hydro Inc.	2.7308%
2011 - 2016 03 31	Midland Power Utility Corporation	0.1196%
2011 - 2016 03 31	Milton Hydro Distribution Inc.	0.5695%
2011 - 2016 03 31	Newmarket-Tay Power Distribution Ltd.	0.6607%
2011 - 2016 03 31	Niagara Peninsula Energy Inc.	0.9945%
2011 - 2016 03 31	Niagara-on-the-Lake Hydro Inc.	0.1586%
2011 - 2016 03 31	Norfolk Power Distribution Inc.	0.3495%
2011 - 2016 03 31	North Bay Hydro Distribution Limited	0.5333%
2011 - 2016 03 31	Northern Ontario Wires Inc.	0.1061%
2011 - 2016 03 31	Oakville Hydro Electricity Distribution Inc.	1.4632%
2011 - 2016 03 31	Orangeville Hydro Limited	0.2120%
2011 - 2016 03 31	Orillia Power Distribution Corporation	0.2722%
2011 - 2016 03 31	Oshawa PUC Networks Inc.	1.2283%
2011 - 2016 03 31	Ottawa River Power Corporation	0.1974%
2011 - 2016 03 31	Peterborough Distribution Incorporated	0.7132%
2011 - 2016 03 31	PowerStream Inc.	6.6383%
2011 - 2016 03 31	PUC Distribution Inc.	0.8687%
2011 - 2016 03 31	Renfrew Hydro Inc.	0.0775%
2011 - 2016 03 31	Rideau St. Lawrence Distribution Inc.	0.1120%
2011 - 2016 03 31	Sioux Lookout Hydro Inc.	0.0841%
2011 - 2016 03 31	St. Thomas Energy Inc.	0.2939%
2011 - 2016 03 31	Thunder Bay Hydro Electricity Distribution Inc.	0.8738%
2011 - 2016 03 31	Tillsonburg Hydro Inc.	0.1280%
2011 - 2016 03 31	Toronto Hydro-Electric System Limited	12.7979%
2011 - 2016 03 31	Veridian Connections Inc.	2.3525%
2011 - 2016 03 31	Wasaga Distribution Inc.	0.1799%
2011 - 2016 03 31	Waterloo North Hydro Inc.	1.0019%
2011 - 2016 03 31	Welland Hydro-Electric System Corp.	0.3879%
2011 - 2016 03 31	Wellington North Power Inc.	0.0632%
2011 - 2016 03 31	West Coast Huron Energy Inc.	0.0653%
2011 - 2016 03 31	Westario Power Inc.	0.5411%
2011 - 2016 03 31	Whitby Hydro Electric Corporation	0.8651%
2011 - 2016 03 31	Woodstock Hydro Services Inc.	0.2548%

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Program Participation & Cost Report
Glossary

#	Term	Definition
1	2011-2014+2015 Extension Legacy Framework Programs	Programs in market from 2011-2015 resulting from the April 23, 2010 GEA CDM Ministerial Directive and funded separately from 2015-2020 Conservation First Framework Programs but whose savings in 2015 are attributed towards the 2015-2020 Conservation First Framework target.
2	2015-2020 Conservation First Framework Programs	Programs in market from 2015-2020 resulting from the March 31, 2014 CFF Ministerial Directive and funded separately from 2011-2014+2015 Extension Legacy Framework Programs.
3	Allocated Target	Each LDC's assigned portion of the Province's 7 TWh Net 2020 Annual Energy Savings Target of the 2015-2020 Conservation First Framework.
4	Allocated Budget	Each LDC's assigned portion of the Province's $ 1.835 billion CDM Plan Budget of the 2015-2020 Conservation First Framework.
5	Province-Wide Program	Programs available to all LDCs to deliver and that are consistent across the province.
6	Regional Program	Programs designed by LDCs to serve their region and approved by the IESO.
7	Local Program	Programs designed by LDCs to serve their communities and approved by the IESO.
8	Pilot Program	A program pilot that may achieve energy or demand savings and is funded extraneous to an LDC's CDM Plan Budget.
9	Initiative	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup) from the 2011-2014+2015 Extension Legacy Framework.
10	Program	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup) from the 2015-2020 Conservation First Framework.

11	Activity	The number of projects.
12	Unit	For a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).
13	Forecast	LDC's forecast of activity, savings, expenditures and cost effectiveness as indicated in each LDC's submitted CDM Plan Cost Effectiveness Tools.
14	Actual	The IESO determined final results of activity, savings, expenditures and cost effectiveness.
15	Progress	A comparison of Actuals versus Forecasts.
16	Full Cost Recovery Progress	For a given year, the percentage calculated by dividing: a) the sum of verified electricity savings for all years of the term up to and including the applicable year for all Programs that receive full cost recovery funding, by b) the Cumulative FCR Milestone, multiplied by 100%, as specified in Schedule A of the Energy Conservation Agreement.
17	Reported Savings	Savings determined by the LDC: 1) for prescriptive projects/programs: calculating quantity x prescriptive savings assumptions; and 2) for engineered or custom program projects/programs: calculated using prescribed methodologies.
18	Verified Savings	Savings determined by the IESO's evaluation, measurement and verification that may adjust reported savings by the realization rate.
19	Gross Savings	Savings determined as either: 1) program activity multiplied by per unit savings assumptions for prescriptive programs; or 2) reported savings multiplied by the realization rate for engineered or custom program streams.
20	Net Savings	The peak demand or energy savings attributable to conservation and demand management activities net of free-riders, etc.
21	Realization Rate	A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.
22	Net-to-Gross Adjustment	The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover.
23	Free-ridership	The percentage of participants who would have implemented the program measure or practice in the absence of the program.

24	Spillover	Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.
25	Incremental Savings	The new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.
26	First Year Savings	The peak demand or energy savings that occur in the year it was achieved (includes resource savings from only new program activity).
27	Annual Savings	The peak demand or energy savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).
28	Demand Savings	Demand savings attributable to conservation and demand management activities.
29	Energy Savings	Energy savings attributable to conservation and demand management activities.
30	Administrative Expenses	Costs incurred in the delivery of a program related to labour, marketing, third-party expenses, value added services or other central services.
31	Participant Incentives	Costs incurred in the delivery of a program related to incenting participants to perform peak demand or energy savings.
32	Total Expenditure	The sum of Administrative Expenses and Participant Incentives
33	Total Resource Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on the total costs of the program including both participants' and utility's costs.
34	Program Administrator Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on costs incurred by the program administrator, including incentive costs and excluding net costs incurred by the participant.
35	Levelized Unit Energy Cost Cost Effectiveness Test	A cost effectiveness test that normalizes the costs incurred by the program administrator per unit of energy or demand reduced.

Program Participation & Cost Report
Message from the IESO Reporting Team

The IESO is pleased to provide LDCs with the Monthly Program Participation & Cost Report.

This report is generally posted on the IESO LDC Extranet by the Friday of the week following the 15th of each month. The report provides province-wide and LDC specific program participation and costs to the extent known based on information received by the IESO from all distribution companies and IESO Value Added Service Provider.

The Monthly Program Participation & Cost Report includes preliminary, unverified results based on information received by the IESO. Upon verification of project information through the IESO Evaluation, Measurement and Verification (EM&V) process, results will be reported as 'verified'. Performance against CDM Plan information is also available in this report and is based on the LDC's approved CDM Plan as at the end of the reporting period. Where two or more LDCs have submitted a joint CDM Plan, the IESO will provide a Monthly Program Participation & Cost Report for each LDC included in the CDM Plan.

The IESO strives to improve on the current reporting processes to provide meaningful and timely information to LDCs. Your feedback is encouraged and appreciated. Should you have any feedback, questions or comments on this report please contact us at LDC.Support@ieso.ca.

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Program Participation & Cost Report
Table of Contents

#	Worksheet Name	Worksheet Description
1	Cover Letter	Provides an overview of the IESO Value Added Services Report.
2	How to Use This Report	Describes the contents and structure of this report.
3	LDC Summary	A high level summary of the Program Participation & Cost Report, including: 1) Progress toward the LDC's a) Allocated 2020 Energy Savings Target; b) Allocated 2015-2020 LDC CDM Plan Budget; c) CDM Plan 2015-2020 Forecasts; 3) Annual savings and spending; 4) Annual LDC CDM Plan spending progress; 5) Graphs describing: a) Contribution to 2020 Target Achievement by program; b) Program to Date LDC CDM Plan Budget Spending by Sector; c) Annual energy savings persistence to 2020 by year; d) Allocated Target achievement progress relative to other LDCs; and e) LDC CDM Plan Budget Spending progress relative to other LDCs.
4	LDC Progress	A comprehensive report of 2015-20 conservation results including: 1) Activity; 2) Savings including; a) Net Energy; b) CDM Plan forecasts, verified actuals and relative progress; c) Allocated Target and Target achievement; and 3) Spending, including participant incentives and administrative expenses.
5	Province-Wide Summary	A high level summary of the Program Participation & Cost Report, including: 1) Progress toward the Province's a) Allocated 2020 Energy Savings Target; b) Allocated 2015-2020 LDC CDM Plan Budget; c) Savings and Spending 2015-2020 Forecasts; 2) Centrally Delivered Spending and Budget 3) LDCs who are forecasted to be over 2015-2020 allocated budget
6	Province-Wide Progress	A comprehensive report of 2015-20 conservation results including: 1) Activity; 2) Savings including; a) Net Energy; b) CDM Plan forecasts, verified actuals and relative progress; c) Allocated Target and Target achievement; and 3) Spending, including participant incentives and administrative expenses.
7	IESO VAS and CD Costs	Insight into the spending and savings of Centrally Delivered Programs and non-program related items.
8	Retrofit Multi-Site Applications	Provision of the LDCs and the Province-Wide aggregated Multi-Site Application activity and costs for each year of the Save on Energy Retrofit Program.
9	Methodology	Description of the methods used to calculate energy savings, financial results and cost-effectiveness.
10	Reference Tables	Consumer Program Province-Wide results allocation to specific LDCs.
11	Glossary	Definitions for the terms used throughout this report.

Program Participation & Cost Report
How to Use This Report

The IESO is pleased to provide you with the Monthly Participation and Cost Report.

This report provides:
1) program participation;
1) electricity savings; and
2) costs
to the extent known based on information received by the IESO in accordance with Section 9.2(c)(i) of the Energy Conservation Agreement.

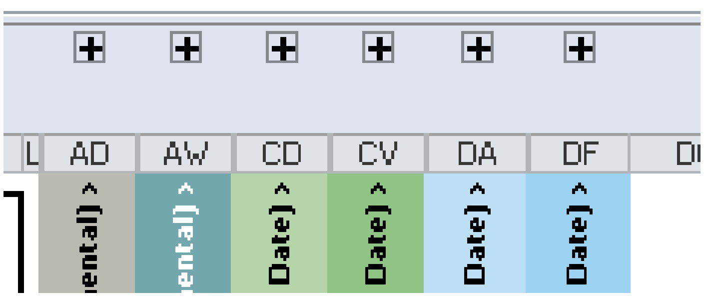
In addition to the above, this report also provides in greater detail:
1) program participation results including:
   a) forecasts; b) actuals; and c) progress (forecast versus (vs) actuals);

2) program savings results including:
   a) net 2020 annual energy savings;
   b) allocated target, target achievement and progress towards target;
   c) incremental net first year energy savings;
   and where available reported by: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

3) program spending including:
   a) participation incentive spending;
   b) administrative expense spending (including IESO value-added services costs);
   c) aggregated total spending;
   and for each cost: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

by both the LDC specific level and the province-wide aggregated level.

This report's format is a dynamic sheet that can be expanded or collapsed by clicking the + button or "Show Detail" feature under the Data tab. Each of the results categories listed above have been grouped together for easy accessibility.



Please note:
1) Cost Effectiveness Test (CET) results including:
   a) total resource cost test;
   b) program administration cost test;
   c) levelized unit energy cost test;
   will not be available for the 2015 program year in this report but will be provided to LDCs once available.

2) forecasts of: a) activity; b) savings; and c) spending; included in this report are
   based on LDC submitted and IESO approved CDM Plan - Cost Effectiveness Tools as of the end of the reporting month.
   (from the i) Program Design; ii) Budget Inputs; iii) Savings Results; and iv) CE Results; worksheets);
   Please note that this does not contain data for Legacy Framework program spending or CFF pilot program activity, savings, spending or cost effectiveness.

3) Annual FCR Progress only includes Full Cost Recovery funded program savings. In future reports, any Pay-for-Performance funded programs will be reported as a separate line item.

4) The complete list of programs and pilots launched into market in 2015 has been included, however no programs and pilots were in market for a sufficient period of time to enable a valid EM&V process. Therefore these programs and pilots have nothing to report at this time and have cells greyed out rather than reporting zero savings or spending. Any results in 2015 will be determined in a subsequent EM&V process and will be included in a future year's Annual Verified Results Report as a 2015 adjustment;

5) Pilot program savings are attributed to the LDC where the pilot program project is located in; and

6) This Monthly Participation and Cost Report provides results for the LDC and province only. No aggregated reporting is provided for LDCs that are part of a joint CDM plan;

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Program Participation & Cost Report
Summary

	CDM Plan	vs	Allocated	Paid Pre-Funding
CFF Target (kWh):	9,383,555		8,719,912	
CFF Budget:	$2,160,676		$2,282,373	$91,531

Ottawa River Power Corporation
As of: 31-Dec-18

Summary of Performance Metrics

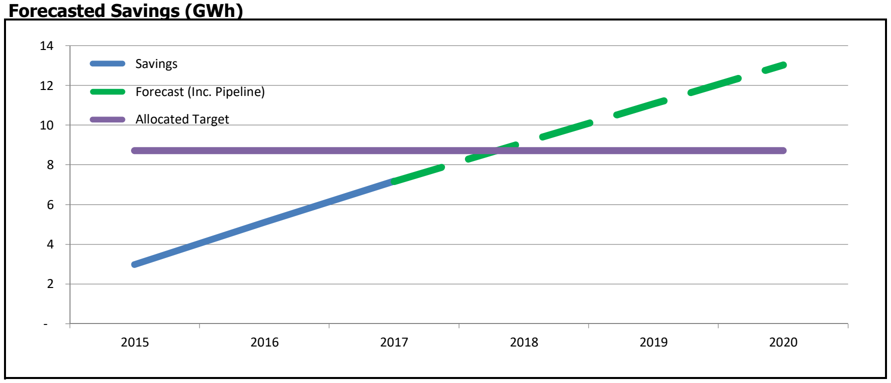
	2018 CDM Results	2018 CDM Plan %	6-year CDM Results	6-year CDM Plan %	6-year Allocated %
Net Energy Savings (kWh) as at 2020	1,225,537	116%	8,394,719	89.5%	96.3%
Total Actual Spending ($)	$ 419,962	105%	$ 1,314,269	60.8%	57.6%
Cost-effectiveness: Total Resource Cost Test (Ratio)	1.40		1.53		
Cost-effectiveness: Program Administrator Cost Test (Ratio)	3.58		2.98		
Cost-effectiveness: Levelized Unit Electricity Cost ($/kWh)	0.02		0.02		

LDC Ranking in the Province out of 67

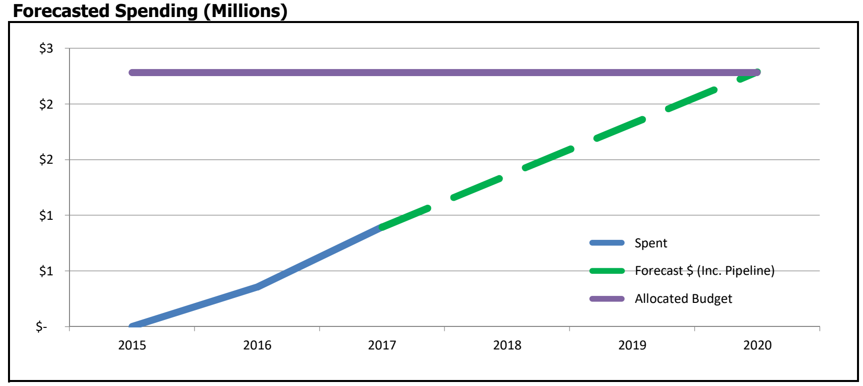
	Total % of 6-year Allocated Budget Spent	Total % of 6-year Allocated Target
This Month:	8	16
Last Month:	19	21

MTI Calculated Payout:	$	107,272	
2015-17 kWh & MTI Rate:		7,151,451	0.15 cents/kWh
Paid MTI Amount:	$	107,272	

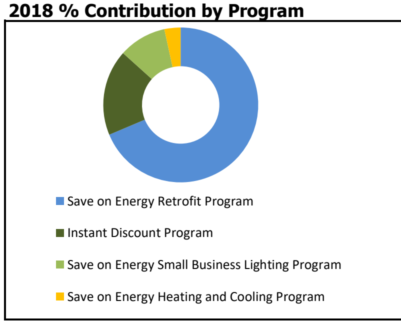
Forecasted Savings (GWh)



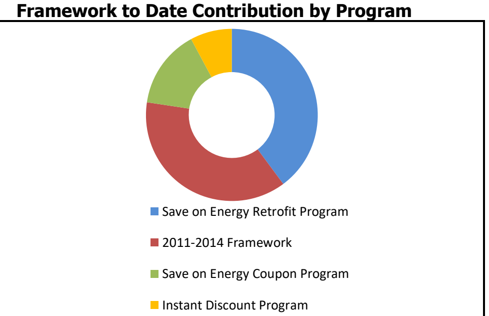
Forecasted Spending (Millions)



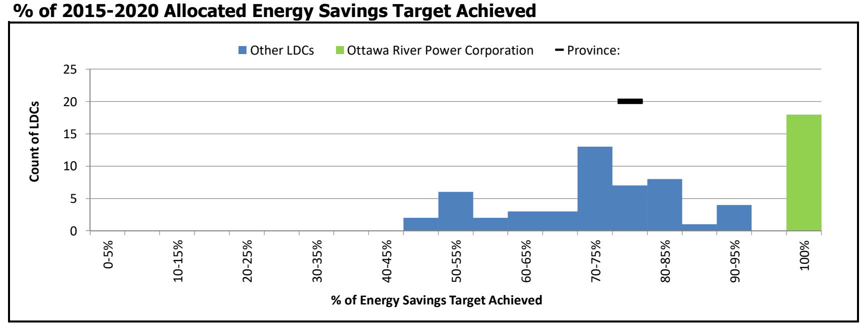
2018 % Contribution by Program



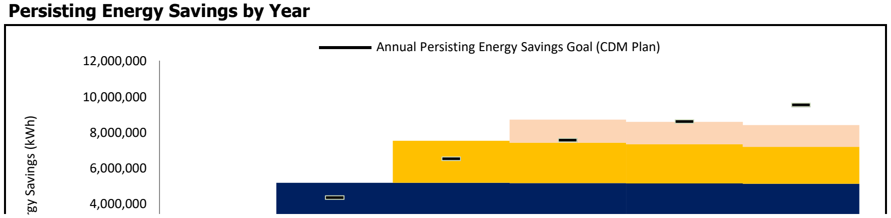
Framework to Date Contribution by Program



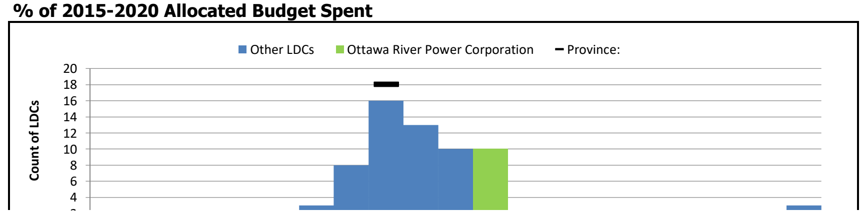
% of 2015-2020 Allocated Energy Savings Target Achieved

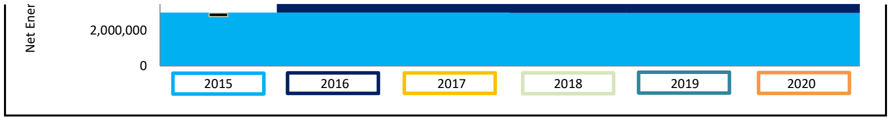


Persisting Energy Savings by Year

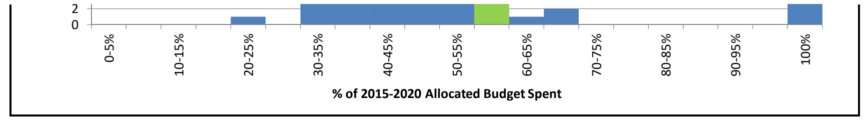


% of 2015-2020 Allocated Budget Spent





Net Ener
2,000,000
0
2015
2016
2017
2018
2019
2020



2
0
0-5%
10-15%
20-25%
30-35%
40-45%
50-55%
60-65%
70-75%
80-85%
90-95%
100%
% of 2015-2020 Allocated Budget Spent

Ottawa River Power Corporation		2018 CDM Plan Forecast		6-year CDM Plan Forecast		Count (Incremental)	Energy Savings (Incremental)	Energy Savings (Persisiting to 2020)	Spending (Year to Date)	Spending (Program to Date)	Cost Effectiveness (Year to Date)	Cost Effectiveness (Program to Date)
As of:	31-Dec-18	% kWh Target	% Budget Spent	% kWh Target	% Budget Spent							
	Program											
Residential (Province-Wide)	Save on Energy Coupon Program	0%	11%	105%	54%							
	Save on Energy Heating and Cooling Program	516%	24%	128%	53%							
	Save on Energy Home Assistance Program	0%	0%	47%	106%							
	Save on Energy Instant Discount Program											
	Save on Energy New Construction Program	0%	0%		19%							
	Save on Energy Smart Thermostat Program											
	Save on Energy Whole Home Program											
	Residential Programs Total	**146%**	**85%**	**155%**	**73%**							
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program	0%	1038%	0%	24%							
	Save on Energy Retrofit Program	111%	84%	69%	52%							
	Save on Energy Retrofit Program - P4P											
	Save on Energy Retrofit Program Enabled Savings											
	Save on Energy Small Business Lighting Program	110%	250%	77%	105%							
	Save on Energy Business Refrigeration Program	99%	78%	34%	22%							
	Save on Energy Energy Performance Program											
	Save on Energy Existing Building Commissioning Program	0%	0%		0%							
	Save on Energy High Performance New Construction Program	0%	0%	0%	1%							
	Save on Energy High Performance New Construction Program Enabled Savings											
	Save on Energy Process & Systems Upgrades Program	0%	0%		7069%							
	Save on Energy Process & Systems Upgrades Program - P4P											
	Save on Energy Process & Systems Upgrades Program Enabled Savings											
	Save on Energy Energy Manager Program	0%	0%		0%							
	Save on Energy Monitoring & Targeting Program	0%	0%		0%							
	Non-Residential Programs Total	**110%**	**109%**	**66%**	**58%**							
Local LDC Programs	**Local LDC Programs Total**											
LDC Innovation	**LDC Innovation Pilots Total**											
Target Gap												
Non-Approved Program												
Unassigned Program												
Energy Savings from 2011-2014 Framework				**105%**								
TOTAL Conservation First (CDM Plan Forecast)		**116%**	**105%**	**89%**	**61%**							
TOTAL Conservation First (Target and Budget Allocation)				**96%**	**58%**							

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Province Wide Dashboard
High Level Summary

as of: **31-Dec-18**

LDCs and IESO Centrally Delivered

5.77 TWh achieved to date. 78% of allocated target and 20% ahead of CDM plans.

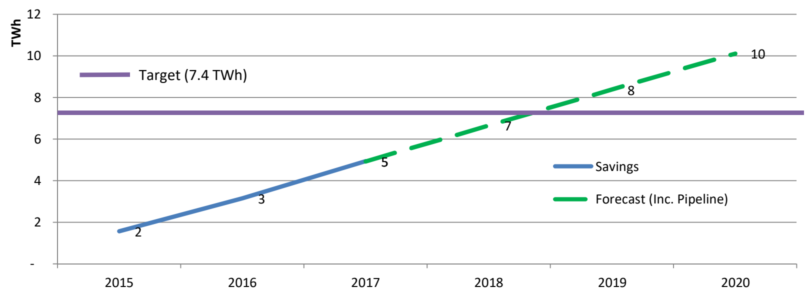
$1099.2 million spent to date. 45% of allocated budget and 16% behind CDM plans.

IAP

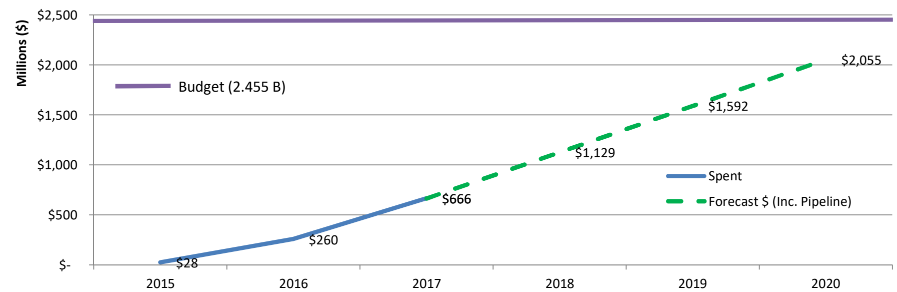
0.41 TWh achieved to date. 31% of allocated target.

$69.3 million spent to date. 27% of allocated budget.

Savings Summary (LDCs and IESO Centrally Delivered)



Spending Summary (LDCs and IESO Centrally Delivered)



LDCs Forecasted Spending in millions at 2020 (excluding First Nations)

		Allocated	Forecast	%
1	Milton Hydro Distribution Inc.	$11.91	$19.03	160%
2	Halton Hills Hydro Inc.	$8.39	$11.99	143%
3	EnWin Utilities Ltd.	$38.42	$50.54	132%
4	Tillsonburg Hydro Inc.	$2.88	$3.84	133%
5	Northern Ontario Wires Inc.	$1.17	$1.44	123%
6	Essex Powerlines Corporation	$8.53	$9.42	110%
7	Thunder Bay Hydro Electricity Distribution Inc.	$12.93	$14.49	112%
8	Brantford Power Inc.	$16.55	$18.24	110%
9	Midland Power Utility Corporation	$2.74	$2.75	101%
10	Orillia Power Distribution Corporation	$4.32	$4.45	103%
11	PUC Distribution Inc.	$7.44	$7.75	104%
12	London Hydro Inc.	$51.19	$52.15	102%
13	Hydro Ottawa Limited	$105.24	$105.74	100%
14	Algoma Power Inc.	$2.11	$2.06	98%
15	Erie Thames Powerlines Corporation	$7.11	$7.51	106%
16	Oakville Hydro Electricity Distribution Inc.	$24.58	$25.30	103%
17	Hydro One Networks Inc.	$338.36	$337.99	100%
18	Renfrew Hydro Inc.	$1.07	$1.04	97%
19	Burlington Hydro Inc.	$25.83	$25.77	100%

Central Services Spending in millions

	Total Actual	Budget
CFF Labour	$2.04	$5.40
Technical Services (to include tech reviewer)	$36.36	$77.40
IESO Infrastructure (IS, IT, CRM, Call Centre)	$6.73	$14.71
LDC Innovation Fund (Not including Whole Home)	$13.09	$30.64
Collaboration Fund	$4.60	$12.22
Capability Building, National Accounts & Energy Managers	$4.77	$37.03
Province Wide Marketing & Market Research	$35.65	$55.73
LDC Performance Incentives (MTI/ATI/ETI)	$68.04	$128.50
Centrally Delivered Programs Total	$27.92	$255.01
Centrally Delivered Provincial Total	$199.21	$616.64

Assumptions

Forecast (Deal Days): Assume savings/spending for 1 event a year.

Pipeline: Includes discounted Retrofit data in the pipeline and all PSUP and IAP projects.

Forecasts are a linear based on past performance, aside from large PSUP and IAP projects.

Forecasts include pipeline information as well as verified and unverified data.

Forecasts for savings are based on a 6 years, spending is based on a 5 years (legacy extension).

Province-Wide Progress

As of: 31-Dec-18

	Program	2018 CDM Plan Forecast % kWh Target	2018 CDM Plan Forecast % Budget Spent	6-year CDM Plan Forecast % kWh Target	6-year CDM Plan Forecast % Budget Spent	Count (Incremental)	Energy Savings (Incremental)	Energy Savings (Persisiting to 2020)	Spending (Year to Date)	Spending (Program to Date)	Cost Effectiveness (Year to Date)	Cost Effectiveness (Prorgram to Date)
Residential (Province-Wide)	Save on Energy Coupon Program	0%	28%	136%	82%							
	Save on Energy Heating and Cooling Program	69%	78%	83%	70%							
	Save on Energy Home Assistance Program	43%	42%	57%	47%							
	Save on Energy Instant Discount Program	3606%	10371%	5155%	8923%							
	Save on Energy New Construction Program	47%	104%	27%	52%							
	Save on Energy Smart Thermostat Program	139%		51%	7%							
	Save on Energy Whole Home Program	0%		25%	0%							
	Residential Programs Total	**129%**	**114%**	**165%**	**74%**							
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program	59%	93%	55%	60%							
	Save on Energy Retrofit Program	57%	103%	77%	60%							
	Save on Energy Retrofit Program - P4P	4%	60%	33%	21%							
	Save on Energy Retrofit Program Enabled Savings		0%	240%	0%							
	Save on Energy Small Business Lighting Program	40%	73%	48%	46%							
	Save on Energy Business Refrigeration Program	77%	64%	43%	39%							
	Save on Energy Existing Building Commissioning Program	5%	53%	14%	32%							
	Save on Energy High Performance New Construction Program	112%	189%	89%	61%							
	Save on Energy High Performance New Construction Program Enabled Savings											
	Save on Energy Process & Systems Upgrades Program	6%	34%	7%	19%							
	Save on Energy Process & Systems Upgrades Program - P4P			152%	93%							
	Save on Energy Process & Systems Upgrades Program Enabled Savings											
	Save on Energy Energy Manager Program	59%	60%	62%	34%							
	Save on Energy Monitoring & Targeting Program	4%	57%	2%	24%							
	Non-Residential Programs Total	**36%**	**78%**	**55%**	**45%**							
< Local LDC Programs	**Local LDC Programs Total**	**11%**	**55%**	**43%**	**37%**							
< LDC Innovation	**LDC Innovation Pilots Total**	**0%**	**0%**	**188%**	**8%**							
Centrally Delivered	**Centrally Delivered Total**	**24%**		**9%**	**32%**							
Target Gap												
Non-Approved Program												
Unassigned Program												
Energy Savings from 2011-2014 Framework				**115%**								
< **TOTAL Conservation First (CDM Plan Forecast)**		**43%**	**114%**	**78%**	**44%**							
TOTAL Conservation First (Target and Budget Allocation)				**78%**	**45%**							
Industrial Accelerator		**58%**	**27%**	**31%**	**27%**							

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Program Participation & Cost Report
IESO Value Added Services Costs and Centrally Delivered Costs

Ottawa River Power Corporation

Unless otherwise stated, all values are unverified

Year end adjustments for invalid coupons that didn't align with retailer sales data are done in the Decembers IESO reporting period.

*The IESO adjusted values reported as Value Added Services Unverified Adjustments from Previous Years to discount savings reported as ve

		Activity	Measures Installed	Net Incremental Energy Savings (kWh)	Administrative Expenses (Variable)	Participant Incentives	Total Value Added Services Spending
Provincial Value Added Services Actuals for the period	Coupon Total	Measures	38,087,165	1,035,550,189	$ 10,575,123	$ 101,324,347	$ 111,899,470
	Instant Discount Program to Date Total	Measures	30,025,794	616,458,657	$ 2,156,480	$ 51,473,356	$ 53,629,837
	Heating and Cooling Program to Date Total	Equipment	201,312	122,766,059	$ 2,157,411	$ 55,935,450	$ 58,092,861
	Smart Thermostat Program to Date Total	Equipment	-	0	$ 81,130	$ 708,890	$ 790,020
	LDC Value Added Services Provincial Total			**1,158,316,248**	**$ 12,813,664**	**$ 157,968,687**	**$ 170,782,351**
LDC Value Added Services Actuals for the period	Coupon Total	Measures	41,363	1,251,787	$ 10,303	$ 109,772	$ 120,075
	Instant Discount Program to Date Total	Measures	36,909	756,823	$ 2,642	$ 63,317	$ 65,959
	Heating and Cooling Program to Date Total	Equipment	313	196,315	$ 4,000	$ 87,600	$ 91,600
	Smart Thermostat Pilot Program to Date Total	Equipment	-	0	$ -	$ -	$ -
	LDC Value Added Services LDC Total			**2,204,926**	**$ 16,945**	**$ 260,689**	**$ 277,634**
Provincial Centrally Delivered Actuals for the period	CFF Labour				$ 2,041,298		$ 2,041,298
	Technical Services (to include tech reviewer)				$ 36,364,605		$ 36,364,605
	IESO Infrastructure (IS, IT, CRM, Call Centre)				$ 6,729,087		$ 6,729,087
	LDC Innovation Fund (Not including Whole Home)				$ 13,087,154		$ 13,087,154
	Collaboration Fund				$ 4,604,611		$ 4,604,611
	Capability Building, National Accounts & Energy Managers				$ 4,774,004		$ 4,774,004
	Province Wide Marketing & Market Research				$ 35,652,336		$ 35,652,336
	LDC Performance Incentives (MTI/ATI/ETI)				$ 68,036,082		$ 68,036,082
	Centrally Delivered Programs Total		133,920.6	12,101,408	$ 23,606,155	$ 4,313,506	$ 27,919,661
	Centrally Delivered Provincial Total				**$ 194,895,330**	**$ 4,313,506**	**$ 199,208,837**

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^ Month

^ By Month

Program Participation & Cost Report
Save on Energy Retrofit Program - Multi-Site Applications

Ottawa River Power Corporation

As of: 31-Dec-18

	Program	Count (Incremental) >	Energy Savings (Incremental) >	Energy Savings (Persisiting to 2020) >	2018 Incentive Budget	2018 Year to Date Incentive Actual	2018 Admin Budget	2018 Year to Date Admin Actual	2018 Total Budget	2018 Year to Date Total Actual	Spending (Year to Date) >	Spending (Program to Date) >
Provincial Actuals for the Period	Save on Energy Retrofit Program				$ 62,176,449	$ 88,348,163	$ 34,428,585	$ 31,622,376	$ 116,024,251	$ 119,970,539		
	Save on Energy Retrofit Program - P4P				$ 28,829,907	$ 17,577,876	$ 21,741,690	-	$ 29,211,918	$ 17,577,876		
	Multi-Site Applications*					$ 6,201,283		$ 494,771		$ 6,696,054		
LDC Actuals for the Period	Save on Energy Retrofit Program				$ 143,478	$ 168,141	$ 125,771	$ 58,774	$ 269,249	$ 226,915		
	Save on Energy Retrofit Program - P4P				-	-	-	-	-	-		
	Multi-Site Applications*					$ 60,180		$ 105		$ 60,285		

*Only contains UNVERIFIED data. For MSA in final verified results please request

a complete project list by emailing LDC.Support@ieso.ca

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Program Participation & Cost Report
Methodology

General

All results are at the end-user level (not including transmission and distribution losses).

Forecasting

Forecasting is a linear formulae used to predict savings and spending. Savings are based on a 72 month period, spending is based on a 60 month period because of the legacy extension year.

Savings and spending are calculated the same aside from the ratio used for the denominator to determine how many more months should be projected forewords ($ uses 60 months, kWh uses 72 months as described above).

Forecasting is calculated as follows:

(V
erif

Pipeline: For Retrofit the pipeline data is based on projects not already submitted.

Pre stage application status' are discounted based on created year. If todays date less the creation data is 3 years or older, the discount rate is a random number between 99% - 100%, 2 years 92% - 100%, 1 year 70% - 100%

Discount rates were established based on an analysis conducted by the IESO including all province wide Retrofit data spanning from 2014 onward.

Retrofit Post stage applications and PSUI applications are not discounted at all.

Instant Discounts is projected forward based on 2018 results but discounted by half, then added back into the forecast.

Instant Discounts savings are expected to be reduced by half as there is only 1 event a year projected for Instant Discounts as appose to 2 that was in 2018.

Coupons Program is removed from future projections as the program is discontinued. It is then added back into the forecast similar to PSUI.

Savings Calculations

#	Project Type	Equations
1	Prescriptive Measures and Projects Programs	Gross Reported Savings = Activity * Per Unit Assumption Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
2	Engineered and Custom Projects / Programs	Gross Reported Savings = Reported Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
3	Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the annual effect of energy savings.

2011-2014+2015 Extension Legacy Framework Initiatives

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings	Project Count
1	saveONenergy Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	Based on project completion date. Count is based of the unit of measurement shown beside the program name. Eg Retrofit is the count of Projects.
2	saveONenergy Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.		
3	saveONenergy Appliance Retirement	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	Savings are considered to begin in the year the appliance is picked up.		
4	saveONenergy HVAC Incentives	Results directly attributed to LDC based on customer applications and postal code.	Savings are considered to begin in the year that the installation occurred.		
5	saveONenergy Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system.	Savings are considered to begin in the year of the project completion date.		
6	saveONenergy Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
7	saveONenergy Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).	
		Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)			
9	saveONenergy Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	
10	saveONenergy New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.		Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
11	saveONenergy Existing Building Commissioning Incentive				

12	saveONenergy Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
13	saveONenergy Monitoring & Targeting				
14	saveONenergy Energy Manager		Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.		
14	saveONenergy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	
15	Aboriginal Conservation Program				

2015-2020 Conservation First Framework Programs

#	Program	Attributing Savings to LDCs	Savings 'Start' Date	Calculating Resource Savings	Project Count
1	Save on Energy Coupon Program	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
2	Save on Energy Heating and Cooling Program	Results directly attributed to LDC based on customer applications and postal code. LDCs may see additional participation, savings and spending relative to the March 2016 Value Added Services Report due to previously unassigned applications completed in 2015. Adjustments to reflect final 2015 verified participation will appear in your July 2016 Value Added Services Report to be issued on August 15, 2016	Savings are considered to begin in the year that the installation occurred.		
3	Save on Energy New Construction Program	Results are directly attributed to LDC based on LDC identified in CDM LDC Report Template.	Savings are considered to begin in the year of the project completion date.		
4	Save on Energy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.		
5	Save on Energy Audit Funding Program	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
6	Save on Energy Retrofit Program	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date as reported in the CDM LDC Report Template	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).	
7	Save on Energy Small Business Lighting Program	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date. Count is based off the actual completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	
8	Save on Energy High Performance New Construction Program	Results are directly attributed to LDC based on LDC identified in the application.		Peak demand and energy savings are determined by the total savings for a given project as reported in the CDM LDC Report Template. Preliminary unverified net savings are calculated by multiplying reported savings by 2014 Net-to-gross ratios and realization rates.	Based on project completion date. Could be a future completion date as incentives are paid before the project is completed.
9	Save on Energy Existing Building Commissioning Program				Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
10	Save on Energy Process and Systems Upgrades Program	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the project was in-service.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
11	Save on Energy Monitoring and Targeting Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011, 2012 or 2013.	Savings are considered to begin in the year in which the incentive project was completed.		
12	Save on Energy Energy Manager Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.		Based on project completion date. Could be a future completion date as incentives are paid before the project is completed.
13	Business Refrigeration Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
14	Social Benchmarking Program		Savings are considered to begin in the year in which the report was sent.	Peak demand and energy savings are determined using the verified measure level (home) per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level (home).	
15	First Nations Conservation Program		Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	

IESO Value Added Services Costs

1) IESO Value Added Services Costs are based on activity reported as of March 31, 2016.

2) Save on Energy Heating & Cooling Program activity may be greater than the March 2016 IESO Value Added Services Report due to previously unassigned applications being assigned to LDCs through the Evaluation, Measurement & Verification Process based on updated applicant postal code mappings. These additional applications and costs will be reflected in the July 2016 IESO Value Added Services Report.

3) Future years may include adjustments to prior years based on delays of Value-Added Service report submissions to IESO from IESO Value-Added Service providers.

4) IESO Value Added Services costs are calculated based on the prevailing IESO Value Added Services Rates as per the applicable IESO Central Services Strategy and Rate Guideline.

Year	Local Distribution Company	Allocation
2016 03 31 - Current	Algoma Power Inc.	0.1820%
2016 03 31 - Current	Atikokan Hydro Inc.	0.0229%
2016 03 31 - Current	Attawapiskat Power Corporation	0.0149%
2016 03 31 - Current	Bluewater Power Distribution Corporation	0.6152%
2016 03 31 - Current	Brantford Power Inc.	0.6715%
2016 03 31 - Current	Burlington Hydro Inc.	1.3392%
2016 03 31 - Current	Canadian Niagara Power Inc.	0.3472%
2016 03 31 - Current	Centre Wellington Hydro Ltd.	0.1058%
2016 03 31 - Current	Chapleau Public Utilities Corporation	0.0282%
2016 03 31 - Current	COLLUS PowerStream Corp.	0.2546%
2016 03 31 - Current	Cooperative Hydro Embrun Inc.	0.0563%
2016 03 31 - Current	E.L.K. Energy Inc.	0.2455%
2016 03 31 - Current	Energy+ Inc.	1.1217%
2016 03 31 - Current	Enersource Hydro Mississauga Inc.	4.6424%
2016 03 31 - Current	Entegrus Powerlines Inc.	0.7018%
2016 03 31 - Current	EnWin Utilities Ltd.	1.4909%
2016 03 31 - Current	Erie Thames Powerlines Corporation	0.3197%
2016 03 31 - Current	Espanola Regional Hydro Distribution Corporation	0.0637%
2016 03 31 - Current	Essex Powerlines Corporation	0.6061%
2016 03 31 - Current	Festival Hydro Inc.	0.3248%
2016 03 31 - Current	Fort Albany Power Corporation	0.0099%
2016 03 31 - Current	Fort Frances Power Corporation	0.0900%
2016 03 31 - Current	Greater Sudbury Hydro Inc.	0.7993%
2016 03 31 - Current	Grimsby Power Incorporated	0.1813%
2016 03 31 - Current	Guelph Hydro Electric Systems Inc.	0.8531%
2016 03 31 - Current	Halton Hills Hydro Inc.	0.5897%
2016 03 31 - Current	Hearst Power Distribution Company Limited	0.0510%
2016 03 31 - Current	Horizon Utilities Corporation	3.7200%
2016 03 31 - Current	Hydro 2000 Inc.	0.0394%
2016 03 31 - Current	Hydro Hawkesbury Inc.	0.1467%
2016 03 31 - Current	Hydro One Brampton Networks Inc.	3.5920%
2016 03 31 - Current	Hydro One Networks Inc.	27.2865%
2016 03 31 - Current	Hydro Ottawa Limited	6.6052%
2016 03 31 - Current	InnPower Corporation	0.3309%
2016 03 31 - Current	Kashechewan Power Corporation	0.0177%
2016 03 31 - Current	Kenora Hydro Electric Corporation Ltd.	0.0896%
2016 03 31 - Current	Kingston Hydro Corporation	0.2939%
2016 03 31 - Current	Kitchener-Wilmot Hydro Inc.	1.5077%
2016 03 31 - Current	Lakefront Utilities Inc.	0.1128%
2016 03 31 - Current	Lakeland Power Distribution Ltd.	0.2288%
2016 03 31 - Current	London Hydro Inc.	2.6114%
2016 03 31 - Current	Midland Power Utility Corporation	0.1014%
2016 03 31 - Current	Milton Hydro Distribution Inc.	0.6579%
2016 03 31 - Current	Newmarket-Tay Power Distribution Ltd.	0.5977%
2016 03 31 - Current	Niagara Peninsula Energy Inc.	0.8158%
2016 03 31 - Current	Niagara-on-the-Lake Hydro Inc.	0.1304%
2016 03 31 - Current	North Bay Hydro Distribution Limited	0.4153%

2016 03 31 - Current	Northern Ontario Wires Inc.	0.0860%
2016 03 31 - Current	Oakville Hydro Electricity Distribution Inc.	1.5097%
2016 03 31 - Current	Orangeville Hydro Limited	0.2004%
2016 03 31 - Current	Orillia Power Distribution Corporation	0.2220%
2016 03 31 - Current	Oshawa PUC Networks Inc.	1.4845%
2016 03 31 - Current	Ottawa River Power Corporation	0.1225%
2016 03 31 - Current	Peterborough Distribution Incorporated	0.4607%
2016 03 31 - Current	PowerStream Inc.	7.8184%
2016 03 31 - Current	PUC Distribution Inc.	0.6545%
2016 03 31 - Current	Renfrew Hydro Inc.	0.0477%
2016 03 31 - Current	Rideau St. Lawrence Distribution Inc.	0.0670%
2016 03 31 - Current	Sioux Lookout Hydro Inc.	0.0776%
2016 03 31 - Current	St. Thomas Energy Inc.	0.2780%
2016 03 31 - Current	Thunder Bay Hydro Electricity Distribution Inc.	0.8172%
2016 03 31 - Current	Tillsonburg Hydro Inc.	0.1169%
2016 03 31 - Current	Toronto Hydro-Electric System Limited	15.5698%
2016 03 31 - Current	Veridian Connections Inc.	2.3879%
2016 03 31 - Current	Wasaga Distribution Inc.	0.1754%
2016 03 31 - Current	Waterloo North Hydro Inc.	0.9590%
2016 03 31 - Current	Welland Hydro-Electric System Corp.	0.3103%
2016 03 31 - Current	Wellington North Power Inc.	0.0570%
2016 03 31 - Current	West Coast Huron Energy Inc.	0.0585%
2016 03 31 - Current	Westario Power Inc.	0.3654%
2016 03 31 - Current	Whitby Hydro Electric Corporation	1.1240%
2011 - 2016 03 31	Algoma Power Inc.	0.2207%
2011 - 2016 03 31	Atikokan Hydro Inc.	0.0265%
2011 - 2016 03 31	Attawapiskat Power Corporation	0.0255%
2011 - 2016 03 31	Bluewater Power Distribution Corporation	0.6460%
2011 - 2016 03 31	Brant County Power Inc.	0.1979%
2011 - 2016 03 31	Brantford Power Inc.	0.7255%
2011 - 2016 03 31	Burlington Hydro Inc.	1.3757%
2011 - 2016 03 31	Cambridge and North Dumfries Hydro Inc.	0.9578%
2011 - 2016 03 31	Canadian Niagara Power Inc.	0.5110%
2011 - 2016 03 31	Centre Wellington Hydro Ltd.	0.1129%
2011 - 2016 03 31	Chapleau Public Utilities Corporation	0.0379%
2011 - 2016 03 31	COLLUS PowerStream Corp.	0.2858%
2011 - 2016 03 31	Cooperative Hydro Embrun Inc.	0.0494%
2011 - 2016 03 31	E.L.K. Energy Inc.	0.2270%
2011 - 2016 03 31	Enersource Hydro Mississauga Inc.	3.9265%
2011 - 2016 03 31	Entegrus Powerlines Inc.	0.7226%
2011 - 2016 03 31	EnWin Utilities Ltd.	1.5542%
2011 - 2016 03 31	Erie Thames Powerlines Corporation	0.3535%
2011 - 2016 03 31	Espanola Regional Hydro Distribution Corporation	0.0821%
2011 - 2016 03 31	Essex Powerlines Corporation	0.6539%
2011 - 2016 03 31	Festival Hydro Inc.	0.3498%
2011 - 2016 03 31	Fort Albany Power Corporation	0.0212%
2011 - 2016 03 31	Fort Frances Power Corporation	0.0995%
2011 - 2016 03 31	Greater Sudbury Hydro Inc.	1.0276%
2011 - 2016 03 31	Grimsby Power Incorporated	0.2279%
2011 - 2016 03 31	Guelph Hydro Electric Systems Inc.	0.8983%
2011 - 2016 03 31	Haldimand County Hydro Inc.	0.4244%
2011 - 2016 03 31	Halton Hills Hydro Inc.	0.5475%
2011 - 2016 03 31	Hearst Power Distribution Company Limited	0.0667%

2011 - 2016 03 31	Horizon Utilities Corporation	4.0429%
2011 - 2016 03 31	Hydro 2000 Inc.	0.0390%
2011 - 2016 03 31	Hydro Hawkesbury Inc.	0.1394%
2011 - 2016 03 31	Hydro One Brampton Networks Inc.	2.8180%
2011 - 2016 03 31	Hydro One Networks Inc.	29.9788%
2011 - 2016 03 31	Hydro Ottawa Limited	5.5954%
2011 - 2016 03 31	InnPower Corporation	0.3951%
2011 - 2016 03 31	Kashechewan Power Corporation	0.0286%
2011 - 2016 03 31	Kenora Hydro Electric Corporation Ltd.	0.0989%
2011 - 2016 03 31	Kingston Hydro Corporation	0.5014%
2011 - 2016 03 31	Kitchener-Wilmot Hydro Inc.	1.6310%
2011 - 2016 03 31	Lakefront Utilities Inc.	0.1907%
2011 - 2016 03 31	Lakeland Power Distribution Ltd.	0.2906%
2011 - 2016 03 31	London Hydro Inc.	2.7308%
2011 - 2016 03 31	Midland Power Utility Corporation	0.1196%
2011 - 2016 03 31	Milton Hydro Distribution Inc.	0.5695%
2011 - 2016 03 31	Newmarket-Tay Power Distribution Ltd.	0.6607%
2011 - 2016 03 31	Niagara Peninsula Energy Inc.	0.9945%
2011 - 2016 03 31	Niagara-on-the-Lake Hydro Inc.	0.1586%
2011 - 2016 03 31	Norfolk Power Distribution Inc.	0.3495%
2011 - 2016 03 31	North Bay Hydro Distribution Limited	0.5333%
2011 - 2016 03 31	Northern Ontario Wires Inc.	0.1061%
2011 - 2016 03 31	Oakville Hydro Electricity Distribution Inc.	1.4632%
2011 - 2016 03 31	Orangeville Hydro Limited	0.2120%
2011 - 2016 03 31	Orillia Power Distribution Corporation	0.2722%
2011 - 2016 03 31	Oshawa PUC Networks Inc.	1.2283%
2011 - 2016 03 31	Ottawa River Power Corporation	0.1974%
2011 - 2016 03 31	Peterborough Distribution Incorporated	0.7132%
2011 - 2016 03 31	PowerStream Inc.	6.6383%
2011 - 2016 03 31	PUC Distribution Inc.	0.8687%
2011 - 2016 03 31	Renfrew Hydro Inc.	0.0775%
2011 - 2016 03 31	Rideau St. Lawrence Distribution Inc.	0.1120%
2011 - 2016 03 31	Sioux Lookout Hydro Inc.	0.0841%
2011 - 2016 03 31	St. Thomas Energy Inc.	0.2939%
2011 - 2016 03 31	Thunder Bay Hydro Electricity Distribution Inc.	0.8738%
2011 - 2016 03 31	Tillsonburg Hydro Inc.	0.1280%
2011 - 2016 03 31	Toronto Hydro-Electric System Limited	12.7979%
2011 - 2016 03 31	Veridian Connections Inc.	2.3525%
2011 - 2016 03 31	Wasaga Distribution Inc.	0.1799%
2011 - 2016 03 31	Waterloo North Hydro Inc.	1.0019%
2011 - 2016 03 31	Welland Hydro-Electric System Corp.	0.3879%
2011 - 2016 03 31	Wellington North Power Inc.	0.0632%
2011 - 2016 03 31	West Coast Huron Energy Inc.	0.0653%
2011 - 2016 03 31	Westario Power Inc.	0.5411%
2011 - 2016 03 31	Whitby Hydro Electric Corporation	0.8651%
2011 - 2016 03 31	Woodstock Hydro Services Inc.	0.2548%

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Program Participation & Cost Report

Message from the IESO Reporting Team

The IESO is pleased to provide LDCs with the Monthly Program Participation & Cost Report.

This report is generally posted on the IESO LDC Extranet by the Friday of the week following the 15th of each month. The report provides province-wide and LDC specific program participation and costs to the extent known based on information received by the IESO from all distribution companies and IESO Value Added Service Provider.

The Monthly Program Participation & Cost Report includes preliminary, unverified results based on information received by the IESO. Upon verification of project information through the IESO Evaluation, Measurement and Verification (EM&V) process, results will be reported as 'verified'. Performance against CDM Plan information is also available in this report and is based on the LDC's approved CDM Plan as at the end of the reporting period. Where two or more LDCs have submitted a joint CDM Plan, the IESO will provide a Monthly Program Participation & Cost Report for each LDC included in the CDM Plan.

The IESO strives to improve on the current reporting processes to provide meaningful and timely information to LDCs. Your feedback is encouraged and appreciated. Should you have any feedback, questions or comments on this report please contact us at LDC.Support@ieso.ca.

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Program Participation & Cost Report
Table of Contents

Program Participation & Cost Report
How to Use This Report

The IESO is pleased to provide you with the Monthly Participation and Cost Report.

This report provides:
1) program participation;
1) electricity savings; and
2) costs

to the extent known based on information received by the IESO in accordance with Section 9.2(c)(i) of the Energy Conservation Agreement.

In addition to the above, this report also provides in greater detail:

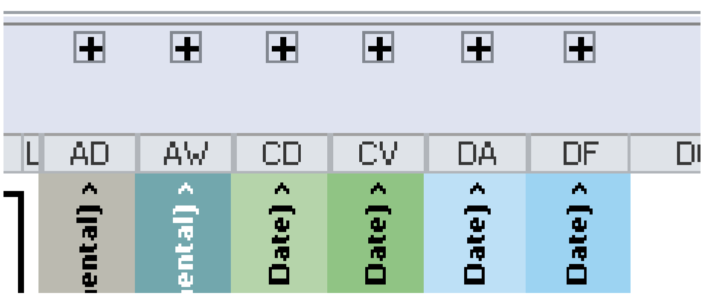
1) program participation results including:
   a) forecasts; b) actuals; and c) progress (forecast versus (vs) actuals);

2) program savings results including:
   a) net 2020 annual energy savings;
   b) allocated target, target achievement and progress towards target;
   c) incremental net first year energy savings;
   and where available reported by: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

3) program spending including:
   a) participation incentive spending;
   b) administrative expense spending (including IESO value-added services costs);
   c) aggregated total spending;
   and for each cost: i) forecasts; ii) unverified and verified actuals; and iii) progress (forecast vs actuals);

by both the LDC specific level and the province-wide aggregated level.

This report's format is a dynamic sheet that can be expanded or collapsed by clicking the + button or "Show Detail" feature under the Data tab. Each of the results categories listed above have been grouped together for easy accessibility.



Please note:

1) Cost Effectiveness Test (CET) results including:
   a) total resource cost test;
   b) program administration cost test;
   c) levelized unit energy cost test;
   will not be available for the 2015 program year in this report but will be provided to LDCs once available.

2) forecasts of: a) activity; b) savings; and c) spending; included in this report are
   based on LDC submitted and IESO approved CDM Plan - Cost Effectiveness Tools as of the end of the reporting month.
   (from the i) Program Design; ii) Budget Inputs; iii) Savings Results; and iv) CE Results; worksheets);
   Please note that this does not contain data for Legacy Framework program spending or CFF pilot program activity, savings, spending or cost effectiveness.

3) Annual FCR Progress only includes Full Cost Recovery funded program savings. In future reports, any Pay-for-Performance funded programs will be reported as a separate line item.

4) The complete list of programs and pilots launched into market in 2015 has been included, however no programs and pilots were in market for a sufficient period of time to enable a valid EM&V process. Therefore these programs and pilots have nothing to report at this time and have cells greyed out rather than reporting zero savings or spending. Any results in 2015 will be determined in a subsequent EM&V process and will be included in a future year's Annual Verified Results Report as a 2015 adjustment;

5) Pilot program savings are attributed to the LDC where the pilot program project is located in; and

6) This Monthly Participation and Cost Report provides results for the LDC and province only. No aggregated reporting is provided for LDCs that are part of a joint CDM plan;

Program Participation & Cost Report
Summary

	CDM Plan	vs	Allocated	Paid Pre-Funding
CFF Target (kWh):	9,383,555		8,719,912	
CFF Budget:	$2,160,676		$2,282,373	$91,531

Ottawa River Power Corporation
As of: 15-Apr-19

Summary of Performance Metrics

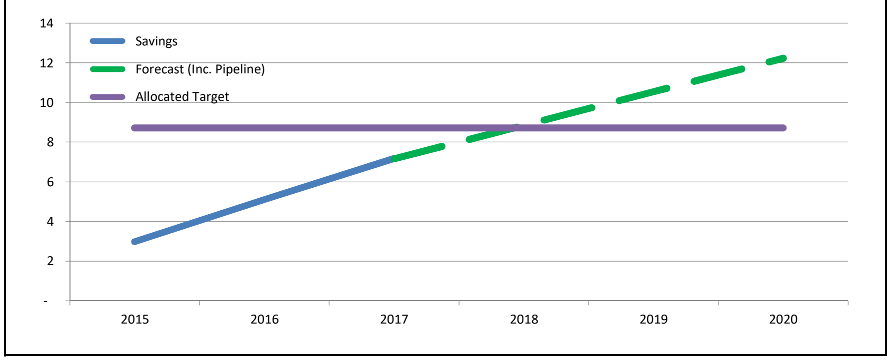
	2019 CDM Results	2019 CDM Plan %	6-year CDM Results	6-year CDM Plan %	6-year Allocated %
Net Energy Savings (kWh) as at 2020	5,089	0%	8,434,233	89.9%	96.7%
Total Actual Spending ($)	$ 48,793	13%	$ 1,363,062	63.1%	59.7%
Cost-effectiveness: Total Resource Cost Test (Ratio)	1.40		1.53		
Cost-effectiveness: Program Administrator Cost Test (Ratio)	3.58		2.98		
Cost-effectiveness: Levelized Unit Electricity Cost ($/kWh)	0.02		0.02		

LDC Ranking in the Province out of 67

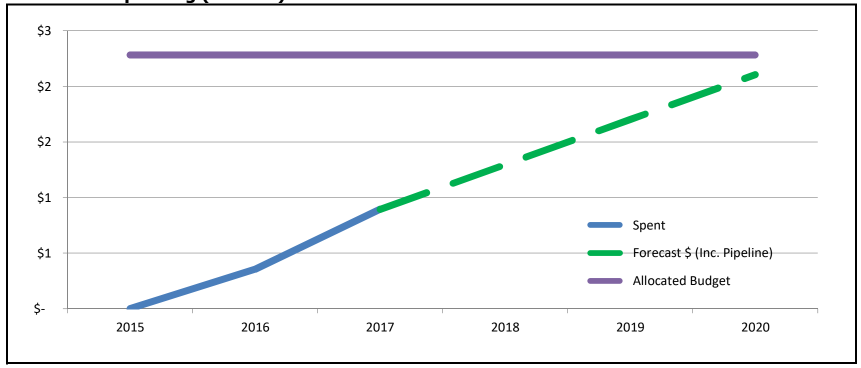
	Total % of 6-year Allocated Budget Spent	Total % of 6-year Allocated Target
This Month:	16	23
Last Month:	16	20

MTI Calculated Payout:	$	107,272	
2015-17 kWh & MTI Rate:		7,151,451	0.15 cents/kWh
Paid MTI Amount:	$	107,272	

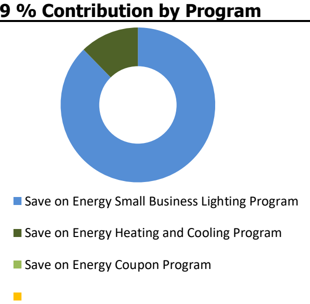
Forecasted Savings (GWh)



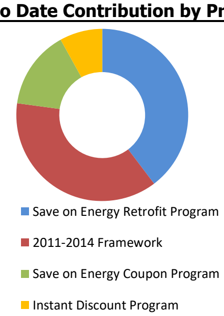
Forecasted Spending (Millions)



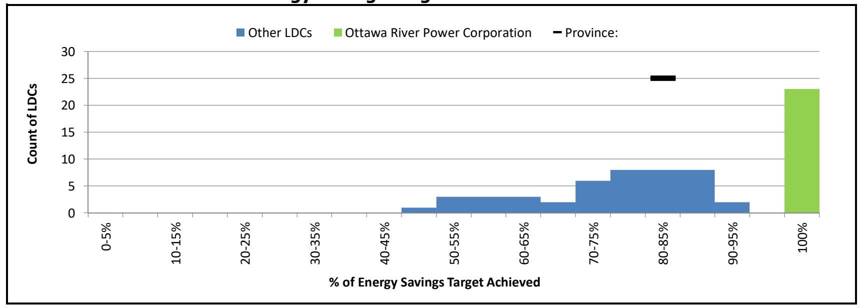
2019 % Contribution by Program



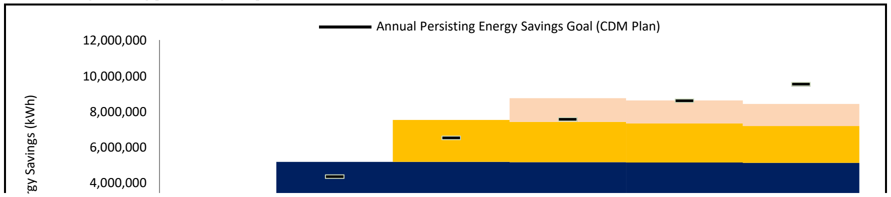
Framework to Date Contribution by Program



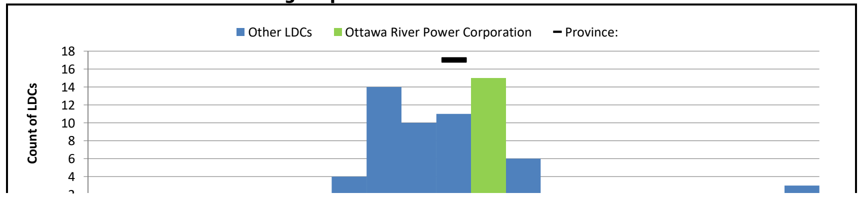
% of 2015-2020 Allocated Energy Savings Target Achieved



Persisting Energy Savings by Year



% of 2015-2020 Allocated Budget Spent



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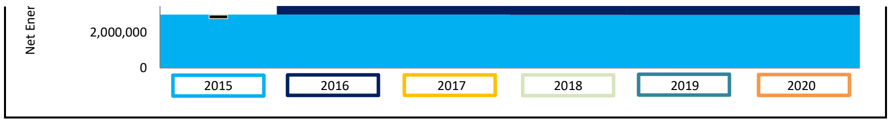

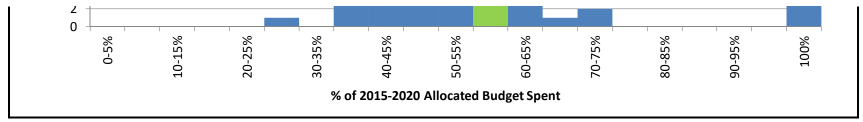

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Ottawa River Power Corporation

As of: 15-Apr-19

	Program	2019 CDM Plan Forecast % kWh Target	2019 CDM Plan Forecast % Budget Spent	6-year CDM Plan Forecast % kWh Target	6-year CDM Plan Forecast % Budget Spent	Count (Incremental)	Energy Savings (Incremental)	Energy Savings (Persisiting to 2020)	Spending (Year to Date)	Spending (Program to Date)	Cost Effectiveness (Year to Date)	Cost Effectiveness (Program to Date)
Residential (Province-Wide)	Save on Energy Coupon Program	0%	2%	105%	54%							
	Save on Energy Heating and Cooling Program	8%	26%	138%	57%							
	Save on Energy Home Assistance Program	0%	5%	47%	108%							
	Save on Energy Instant Discount Program											
	Save on Energy New Construction Program	0%	63%		32%							
	Save on Energy Smart Thermostat Program											
	Save on Energy Whole Home Program											
	Residential Programs Total	**1%**	**21%**	**158%**	**75%**							
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program	0%	1%	0%	25%							
	Save on Energy Retrofit Program	0%	9%	69%	54%							
	Save on Energy Retrofit Program - P4P											
	Save on Energy Retrofit Program Enabled Savings											
	Save on Energy Small Business Lighting Program	4%	26%	78%	110%							
	Save on Energy Business Refrigeration Program	0%	6%	34%	24%							
	Save on Energy Energy Performance Program											
	Save on Energy Existing Building Commissioning Program	0%	0%		0%							
	Save on Energy High Performance New Construction Program	0%	39%	0%	2%							
	Save on Energy High Performance New Construction Program Enabled Savings											
	Save on Energy Process & Systems Upgrades Program	0%	0%		7069%							
	Save on Energy Process & Systems Upgrades Program - P4P											
	Save on Energy Process & Systems Upgrades Program Enabled Savings											
	Save on Energy Energy Manager Program	0%	0%		0%							
	Save on Energy Monitoring & Targeting Program	0%	0%		0%							
	Non-Residential Programs Total	**0%**	**11%**	**66%**	**60%**							
Local LDC Programs	**Local LDC Programs Total**											
LDC Innovation	**LDC Innovation Pilots Total**											
Target Gap												
Non-Approved Program												
Unassigned Program												
Energy Savings from 2011-2014 Framework				**105%**								
TOTAL Conservation First (CDM Plan Forecast)		**0%**	**13%**	**90%**	**63%**							
TOTAL Conservation First (Target and Budget Allocation)				**97%**	**60%**							

Province Wide Dashboard
High Level Summary

as of: **15-Apr-19**

LDCs and IESO Centrally Delivered

6.06 TWh achieved to date. 82% of allocated target and 16% ahead of CDM plans.

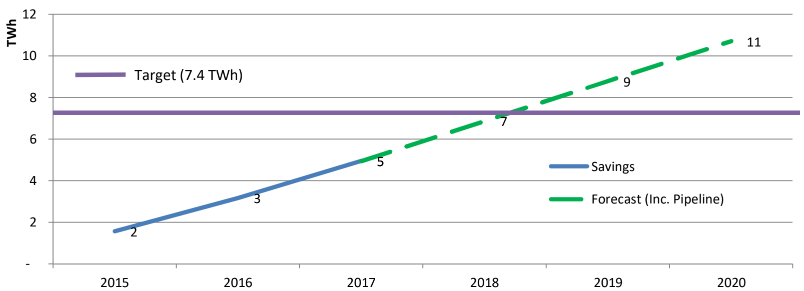
$1268.1 million spent to date. 52% of allocated budget and 19% behind CDM plans.

IAP

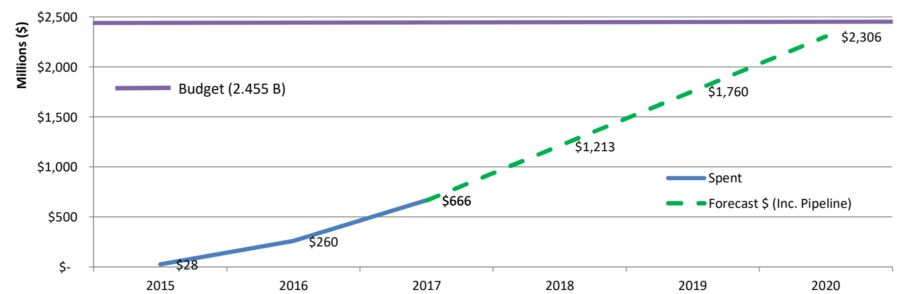
0.42 TWh achieved to date. 32% of allocated target.

$69.3 million spent to date. 27% of allocated budget.

Savings Summary (LDCs and IESO Centrally Delivered)



Spending Summary (LDCs and IESO Centrally Delivered)



LDCs Forecasted Spending in millions at 2020 (excluding First Nations)

		Allocated	Forecast	%
1	Milton Hydro Distribution Inc.	$11.91	$19.03	160%
2	Halton Hills Hydro Inc.	$8.39	$11.99	143%
3	EnWin Utilities Ltd.	$38.42	$48.31	126%
4	Tillsonburg Hydro Inc.	$2.88	$2.89	100%
5	Northern Ontario Wires Inc.	$1.17	$1.45	123%
6	Essex Powerlines Corporation	$8.53	$12.12	142%
7	Thunder Bay Hydro Electricity Distribution Inc.	$12.93	$20.95	162%
8	Brantford Power Inc.	$16.55	$17.84	108%
9	Midland Power Utility Corporation	$2.74	$2.57	94%
10	Orillia Power Distribution Corporation	$4.32	$4.46	103%
11	PUC Distribution Inc.	$7.44	$7.30	98%
12	London Hydro Inc.	$51.19	$49.80	97%
13	Hydro Ottawa Limited	$105.24	$92.54	88%
14	Algoma Power Inc.	$2.11	$1.93	92%
15	Erie Thames Powerlines Corporation	$7.11	$14.22	200%
16	Oakville Hydro Electricity Distribution Inc.	$24.58	$25.30	103%
17	Hydro One Networks Inc.	$338.36	$348.59	103%
18	Renfrew Hydro Inc.	$1.07	$1.03	96%
19	Burlington Hydro Inc.	$25.83	$25.77	100%

Central Services Spending in millions

	Total Actual	Budget
CFF Labour	$2.04	$5.40
Technical Services (to include tech reviewer)	$36.36	$77.40
IESO Infrastructure (IS, IT, CRM, Call Centre)	$6.73	$14.71
LDC Innovation Fund (Not including Whole Home)	$13.09	$30.64
Collaboration Fund	$4.60	$12.22
Capability Building, National Accounts & Energy Managers	$4.77	$37.03
Province Wide Marketing & Market Research	$35.65	$55.73
LDC Performance Incentives (MTI/ATI/ETI)	$68.04	$128.50
Centrally Delivered Programs Total	$27.92	$255.01
Centrally Delivered Provincial Total	$199.21	$616.64

Assumptions

Forecast (Deal Days): Assume savings/spending for 1 event a year.

Pipeline: Includes discounted Retrofit data in the pipeline and all PSUP and IAP projects.

Forecasts are a linear based on past performance, aside from large PSUP and IAP projects.

Forecasts include pipeline information as well as verified and unverified data.

Forecasts for savings are based on a 6 years, spending is based on a 5 years (legacy extension).

Province-Wide Progress

As of: 15-Apr-19

	Program	2019 CDM Plan Forecast % kWh Target	2019 CDM Plan Forecast % Budget Spent	6-year CDM Plan Forecast % kWh Target	6-year CDM Plan Forecast % Budget Spent	Count (Incremental)	Energy Savings (Incremental)	Energy Savings (Persisiting to 2020)	Spending (Year to Date)	Spending (Program to Date)	Cost Effectiveness (Year to Date)	Cost Effectiveness (Prorgram to Date)
Residential (Province-Wide)	Save on Energy Coupon Program	0%	2%	136%	82%							
	Save on Energy Heating and Cooling Program	2%	23%	88%	73%							
	Save on Energy Home Assistance Program	1%	5%	58%	48%							
	Save on Energy Instant Discount Program			5307%	9325%							
	Save on Energy New Construction Program	4%	24%	33%	58%							
	Save on Energy Smart Thermostat Program	0%	45%	112%	32%							
	Save on Energy Whole Home Program	0%	0%	25%	0%							
	Residential Programs Total	**1%**	**16%**	**168%**	**83%**							
Non-Residential (Province-Wide)	Save on Energy Audit Funding Program	0%	20%	56%	64%							
	Save on Energy Retrofit Program	2%	35%	84%	66%							
	Save on Energy Retrofit Program - P4P	0%	13%	38%	26%							
	Save on Energy Retrofit Program Enabled Savings		0%	240%	0%							
	Save on Energy Small Business Lighting Program	15%	32%	52%	53%							
	Save on Energy Business Refrigeration Program	13%	21%	49%	44%							
	Save on Energy Existing Building Commissioning Program	0%	5%	14%	34%							
	Save on Energy High Performance New Construction Program	1%	24%	92%	64%							
	Save on Energy High Performance New Construction Program Enabled Savings											
	Save on Energy Process & Systems Upgrades Program	1%	5%	9%	21%							
	Save on Energy Process & Systems Upgrades Program - P4P			152%	93%							
	Save on Energy Process & Systems Upgrades Program Enabled Savings											
	Save on Energy Energy Manager Program	12%	15%	68%	37%							
	Save on Energy Monitoring & Targeting Program	0%	11%	2%	26%							
	Non-Residential Programs Total	**2%**	**20%**	**61%**	**49%**							
Local LDC Programs	**Local LDC Programs Total**	**0%**	**15%**	**43%**	**40%**							
LDC Innovation	**LDC Innovation Pilots Total**	**0%**	**0%**	**188%**	**8%**							
Centrally Delivered	**Centrally Delivered Total**	**10%**		**9%**	**49%**							
Target Gap												
Non-Approved Program												
Unassigned Program												
Energy Savings from 2011-2014 Framework				**115%**								
TOTAL Conservation First (CDM Plan Forecast)		**2%**	**48%**	**82%**	**52%**							
TOTAL Conservation First (Target and Budget Allocation)				**82%**	**52%**							
Industrial Accelerator		**5%**	**27%**	**32%**	**27%**							

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Program Participation & Cost Report
IESO Value Added Services Costs and Centrally Delivered Costs

Ottawa River Power Corporation

Unless otherwise stated, all values are unverified

Year end adjustments for invalid coupons that didn't align with retailer sales data are done in the Decembers IESO reporting period.

*The IESO adjusted values reported as Value Added Services Unverified Adjustments from Previous Years to discount savings reported as ve

		Activity	Measures Installed	Net Incremental Energy Savings (kWh)	Administrative Expenses (Variable)	Participant Incentives	Total Value Added Services Spending
Provincial Value Added Services Actuals for the period	Coupon Total	Measures	38,087,165	1,035,550,189	$ 10,575,058	$ 101,323,731	$ 111,898,788
	Instant Discount Program to Date Total	Measures	31,123,156	629,597,669	$ 2,242,531	$ 53,796,834	$ 56,039,366
	Heating and Cooling Program to Date Total	Equipment	212,703	129,777,545	$ 2,403,050	$ 99,195,550	$ 101,598,600
	Smart Thermostat Program to Date Total	Equipment	21,095	6,195,178	$ 79,405	$ 794,050	$ 873,455
	LDC Value Added Services Provincial Total			**1,801,120,581**	**$ 15,300,044**	**$ 255,110,165**	**$ 270,410,209**
LDC Value Added Services Actuals for the period	Coupon Total	Measures	41,363	1,251,787	$ 10,303	$ 109,772	$ 120,075
	Instant Discount Program to Date Total	Measures	38,422	775,046	$ 2,763	$ 66,208	$ 68,971
	Heating and Cooling Program to Date Total	Equipment	340	211,435	$ 4,468	$ 94,100	$ 98,568
	Smart Thermostat Pilot Program to Date Total	Equipment	-	0	$ -	$ -	$ -
	LDC Value Added Services LDC Total			**2,238,268**	**$ 17,534**	**$ 270,080**	**$ 287,614**
Provincial Centrally Delivered Actuals for the period	CFF Labour				$ 2,041,298		$ 2,041,298
	Technical Services (to include tech reviewer)				$ 36,364,605		$ 36,364,605
	IESO Infrastructure (IS, IT, CRM, Call Centre)				$ 6,729,087		$ 6,729,087
	LDC Innovation Fund (Not including Whole Home)				$ 13,087,154		$ 13,087,154
	Collaboration Fund				$ 4,604,611		$ 4,604,611
	Capability Building, National Accounts & Energy Managers				$ 4,774,004		$ 4,774,004
	Province Wide Marketing & Market Research				$ 35,652,336		$ 35,652,336
	LDC Performance Incentives (MTI/ATI/ETI)				$ 68,036,082		$ 68,036,082
	Centrally Delivered Programs Total		161,778.2	12,529,974	$ 23,606,155	$ 4,313,506	$ 27,919,661
	Centrally Delivered Provincial Total				**$ 194,895,330**	**$ 4,313,506**	**$ 199,208,837**

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^ Month

^ By Month

Program Participation & Cost Report
Save on Energy Retrofit Program - Multi-Site Applications

Ottawa River Power Corporation

As of: 15-Apr-19

	Program	Count (Incremental) >	Energy Savings (Incremental) >	Energy Savings (Persisiting to 2020) >	2019 Incentive Budget	2019 Year to Date Incentive Actual	2019 Admin Budget	2019 Year to Date Admin Actual	2019 Total Budget	2019 Year to Date Total Actual	Spending (Year to Date) >
Provincial Actuals for the Period	Save on Energy Retrofit Program				$ 64,921,809	$ 22,884,868	$ 35,502,389	$ 7,362,819	$ 86,278,803	$ 30,247,687	
	Save on Energy Retrofit Program - P4P				$ 25,016,698	$ 5,484,635	$ 19,107,840	-	$ 42,612,031	$ 5,484,635	
	Multi-Site Applications*					$ 2,560,615		$ 222,980		$ 2,783,595	
LDC Actuals for the Period	Save on Energy Retrofit Program				$ 131,721	-	$ 130,952	$ 24,069	$ 262,673	$ 24,069	
	Save on Energy Retrofit Program - P4P				-	-	-	-	-	-	
	Multi-Site Applications*					-		-		-	

*Only contains UNVERIFIED data. For MSA in final verified results please request

a complete project list by emailing LDC.Support@ieso.ca

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Program Participation & Cost Report
Methodology

General

All results are at the end-user level (not including transmission and distribution losses).

Forecasting

Forecasting is a linear formulae used to predict savings and spending. Savings are based on a 72 month period, spending is based on a 60 month period because of the legacy extension year.

Savings and spending are calculated the same aside from the ratio used for the denominator to determine how many more months should be projected forewords ($ uses 60 months, kWh uses 72 months as described above).

Forecasting is calculated as follows:

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Pipeline: For Retrofit the pipeline data is based on projects not already submitted.

Pre stage application status' are discounted based on created year. If todays date less the creation data is 3 years or older, the discount rate is a random number between 99% - 100%, 2 years 92% - 100%, 1 year 70% - 100%

Discount rates were established based on an analysis conducted by the IESO including all province wide Retrofit data spanning from 2014 onward.

Retrofit Post stage applications and PSUI applications are not discounted at all.

Instant Discounts is projected forward based on 2018 results but discounted by half, then added back into the forecast.

Instant Discounts savings are expected to be reduced by half as there is only 1 event a year projected for Instant Discounts as appose to 2 that was in 2018.

Coupons Program is removed from future projections as the program is discontinued. It is then added back into the forecast similar to PSUI.

Savings Calculations

#	Project Type	Equations
1	Prescriptive Measures and Projects Programs	Gross Reported Savings = Activity * Per Unit Assumption Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
2	Engineered and Custom Projects / Programs	Gross Reported Savings = Reported Savings Gross Verified Savings = Gross Reported Savings * Realization Rate Net Verified Savings = Gross Verified Savings * Net-to-Gross Ratio All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)
3	Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the annual effect of energy savings.

2011-2014+2015 Extension Legacy Framework Initiatives

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings	Project Count
1	saveONenergy Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	Based on project completion date. Count is based of the unit of measurement shown beside the program name. Eg Retrofit is the count of Projects.
2	saveONenergy Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.		
3	saveONenergy Appliance Retirement	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	Savings are considered to begin in the year the appliance is picked up.		
4	saveONenergy HVAC Incentives	Results directly attributed to LDC based on customer applications and postal code.	Savings are considered to begin in the year that the installation occurred.		
5	saveONenergy Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system.	Savings are considered to begin in the year of the project completion date.		
6	saveONenergy Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
7	saveONenergy Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).	
		Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)			
9	saveONenergy Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	
10	saveONenergy New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.		Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
11	saveONenergy Existing Building Commissioning Incentive				

12	saveONenergy Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
13	saveONenergy Monitoring & Targeting				
14	saveONenergy Energy Manager		Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.		
14	saveONenergy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	
15	Aboriginal Conservation Program				

2015-2020 Conservation First Framework Programs

#	Program	Attributing Savings to LDCs	Savings 'Start' Date	Calculating Resource Savings	Project Count
1	Save on Energy Coupon Program	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
2	Save on Energy Heating and Cooling Program	Results directly attributed to LDC based on customer applications and postal code. LDCs may see additional participation, savings and spending relative to the March 2016 Value Added Services Report due to previously unassigned applications completed in 2015. Adjustments to reflect final 2015 verified participation will appear in your July 2016 Value Added Services Report to be issued on August 15, 2016	Savings are considered to begin in the year that the installation occurred.		
3	Save on Energy New Construction Program	Results are directly attributed to LDC based on LDC identified in CDM LDC Report Template.	Savings are considered to begin in the year of the project completion date.		
4	Save on Energy Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.		
5	Save on Energy Audit Funding Program	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
6	Save on Energy Retrofit Program	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date as reported in the CDM LDC Report Template	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).	
7	Save on Energy Small Business Lighting Program	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date. Count is based off the actual completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	
8	Save on Energy High Performance New Construction Program	Results are directly attributed to LDC based on LDC identified in the application.		Peak demand and energy savings are determined by the total savings for a given project as reported in the CDM LDC Report Template. Preliminary unverified net savings are calculated by multiplying reported savings by 2014 Net-to-gross ratios and realization rates.	Based on project completion date. Could be a future completion date as incentives are paid before the project is completed.
9	Save on Energy Existing Building Commissioning Program				Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
10	Save on Energy Process and Systems Upgrades Program	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the project was in-service.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).	
11	Save on Energy Monitoring and Targeting Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011, 2012 or 2013.	Savings are considered to begin in the year in which the incentive project was completed.		
12	Save on Energy Energy Manager Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.		Based on project completion date. Could be a future completion date as incentives are paid before the project is completed.
13	Business Refrigeration Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).	Based on project completion date. Count is the number of line items (rows) that are entered into the "Program Activity Information" tab in the LDC Report Template.
14	Social Benchmarking Program		Savings are considered to begin in the year in which the report was sent.	Peak demand and energy savings are determined using the verified measure level (home) per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level (home).	
15	First Nations Conservation Program		Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.	

IESO Value Added Services Costs

1) IESO Value Added Services Costs are based on activity reported as of March 31, 2016.

2) Save on Energy Heating & Cooling Program activity may be greater than the March 2016 IESO Value Added Services Report due to previously unassigned applications being assigned to LDCs through the Evaluation, Measurement & Verification Process based on updated applicant postal code mappings. These additional applications and costs will be reflected in the July 2016 IESO Value Added Services Report.

3) Future years may include adjustments to prior years based on delays of Value-Added Service report submissions to IESO from IESO Value-Added Service providers.

4) IESO Value Added Services costs are calculated based on the prevailing IESO Value Added Services Rates as per the applicable IESO Central Services Strategy and Rate Guideline.

Year	Local Distribution Company	Allocation
2016 03 31 - Current	Algoma Power Inc.	0.1820%
2016 03 31 - Current	Atikokan Hydro Inc.	0.0229%
2016 03 31 - Current	Attawapiskat Power Corporation	0.0149%
2016 03 31 - Current	Bluewater Power Distribution Corporation	0.6152%
2016 03 31 - Current	Brantford Power Inc.	0.6715%
2016 03 31 - Current	Burlington Hydro Inc.	1.3392%
2016 03 31 - Current	Canadian Niagara Power Inc.	0.3472%
2016 03 31 - Current	Centre Wellington Hydro Ltd.	0.1058%
2016 03 31 - Current	Chapleau Public Utilities Corporation	0.0282%
2016 03 31 - Current	COLLUS PowerStream Corp.	0.2546%
2016 03 31 - Current	Cooperative Hydro Embrun Inc.	0.0563%
2016 03 31 - Current	E.L.K. Energy Inc.	0.2455%
2016 03 31 - Current	Energy+ Inc.	1.1217%
2016 03 31 - Current	Enersource Hydro Mississauga Inc.	4.6424%
2016 03 31 - Current	Entegrus Powerlines Inc.	0.7018%
2016 03 31 - Current	EnWin Utilities Ltd.	1.4909%
2016 03 31 - Current	Erie Thames Powerlines Corporation	0.3197%
2016 03 31 - Current	Espanola Regional Hydro Distribution Corporation	0.0637%
2016 03 31 - Current	Essex Powerlines Corporation	0.6061%
2016 03 31 - Current	Festival Hydro Inc.	0.3248%
2016 03 31 - Current	Fort Albany Power Corporation	0.0099%
2016 03 31 - Current	Fort Frances Power Corporation	0.0900%
2016 03 31 - Current	Greater Sudbury Hydro Inc.	0.7993%
2016 03 31 - Current	Grimsby Power Incorporated	0.1813%
2016 03 31 - Current	Guelph Hydro Electric Systems Inc.	0.8531%
2016 03 31 - Current	Halton Hills Hydro Inc.	0.5897%
2016 03 31 - Current	Hearst Power Distribution Company Limited	0.0510%
2016 03 31 - Current	Horizon Utilities Corporation	3.7200%
2016 03 31 - Current	Hydro 2000 Inc.	0.0394%
2016 03 31 - Current	Hydro Hawkesbury Inc.	0.1467%
2016 03 31 - Current	Hydro One Brampton Networks Inc.	3.5920%
2016 03 31 - Current	Hydro One Networks Inc.	27.2865%
2016 03 31 - Current	Hydro Ottawa Limited	6.6052%
2016 03 31 - Current	InnPower Corporation	0.3309%
2016 03 31 - Current	Kashechewan Power Corporation	0.0177%
2016 03 31 - Current	Kenora Hydro Electric Corporation Ltd.	0.0896%
2016 03 31 - Current	Kingston Hydro Corporation	0.2939%
2016 03 31 - Current	Kitchener-Wilmot Hydro Inc.	1.5077%
2016 03 31 - Current	Lakefront Utilities Inc.	0.1128%
2016 03 31 - Current	Lakeland Power Distribution Ltd.	0.2288%
2016 03 31 - Current	London Hydro Inc.	2.6114%
2016 03 31 - Current	Midland Power Utility Corporation	0.1014%
2016 03 31 - Current	Milton Hydro Distribution Inc.	0.6579%
2016 03 31 - Current	Newmarket-Tay Power Distribution Ltd.	0.5977%
2016 03 31 - Current	Niagara Peninsula Energy Inc.	0.8158%
2016 03 31 - Current	Niagara-on-the-Lake Hydro Inc.	0.1304%
2016 03 31 - Current	North Bay Hydro Distribution Limited	0.4153%

2016 03 31 - Current	Northern Ontario Wires Inc.	0.0860%
2016 03 31 - Current	Oakville Hydro Electricity Distribution Inc.	1.5097%
2016 03 31 - Current	Orangeville Hydro Limited	0.2004%
2016 03 31 - Current	Orillia Power Distribution Corporation	0.2220%
2016 03 31 - Current	Oshawa PUC Networks Inc.	1.4845%
2016 03 31 - Current	Ottawa River Power Corporation	0.1225%
2016 03 31 - Current	Peterborough Distribution Incorporated	0.4607%
2016 03 31 - Current	PowerStream Inc.	7.8184%
2016 03 31 - Current	PUC Distribution Inc.	0.6545%
2016 03 31 - Current	Renfrew Hydro Inc.	0.0477%
2016 03 31 - Current	Rideau St. Lawrence Distribution Inc.	0.0670%
2016 03 31 - Current	Sioux Lookout Hydro Inc.	0.0776%
2016 03 31 - Current	St. Thomas Energy Inc.	0.2780%
2016 03 31 - Current	Thunder Bay Hydro Electricity Distribution Inc.	0.8172%
2016 03 31 - Current	Tillsonburg Hydro Inc.	0.1169%
2016 03 31 - Current	Toronto Hydro-Electric System Limited	15.5698%
2016 03 31 - Current	Veridian Connections Inc.	2.3879%
2016 03 31 - Current	Wasaga Distribution Inc.	0.1754%
2016 03 31 - Current	Waterloo North Hydro Inc.	0.9590%
2016 03 31 - Current	Welland Hydro-Electric System Corp.	0.3103%
2016 03 31 - Current	Wellington North Power Inc.	0.0570%
2016 03 31 - Current	West Coast Huron Energy Inc.	0.0585%
2016 03 31 - Current	Westario Power Inc.	0.3654%
2016 03 31 - Current	Whitby Hydro Electric Corporation	1.1240%
2011 - 2016 03 31	Algoma Power Inc.	0.2207%
2011 - 2016 03 31	Atikokan Hydro Inc.	0.0265%
2011 - 2016 03 31	Attawapiskat Power Corporation	0.0255%
2011 - 2016 03 31	Bluewater Power Distribution Corporation	0.6460%
2011 - 2016 03 31	Brant County Power Inc.	0.1979%
2011 - 2016 03 31	Brantford Power Inc.	0.7255%
2011 - 2016 03 31	Burlington Hydro Inc.	1.3757%
2011 - 2016 03 31	Cambridge and North Dumfries Hydro Inc.	0.9578%
2011 - 2016 03 31	Canadian Niagara Power Inc.	0.5110%
2011 - 2016 03 31	Centre Wellington Hydro Ltd.	0.1129%
2011 - 2016 03 31	Chapleau Public Utilities Corporation	0.0379%
2011 - 2016 03 31	COLLUS PowerStream Corp.	0.2858%
2011 - 2016 03 31	Cooperative Hydro Embrun Inc.	0.0494%
2011 - 2016 03 31	E.L.K. Energy Inc.	0.2270%
2011 - 2016 03 31	Enersource Hydro Mississauga Inc.	3.9265%
2011 - 2016 03 31	Entegrus Powerlines Inc.	0.7226%
2011 - 2016 03 31	EnWin Utilities Ltd.	1.5542%
2011 - 2016 03 31	Erie Thames Powerlines Corporation	0.3535%
2011 - 2016 03 31	Espanola Regional Hydro Distribution Corporation	0.0821%
2011 - 2016 03 31	Essex Powerlines Corporation	0.6539%
2011 - 2016 03 31	Festival Hydro Inc.	0.3498%
2011 - 2016 03 31	Fort Albany Power Corporation	0.0212%
2011 - 2016 03 31	Fort Frances Power Corporation	0.0995%
2011 - 2016 03 31	Greater Sudbury Hydro Inc.	1.0276%
2011 - 2016 03 31	Grimsby Power Incorporated	0.2279%
2011 - 2016 03 31	Guelph Hydro Electric Systems Inc.	0.8983%
2011 - 2016 03 31	Haldimand County Hydro Inc.	0.4244%
2011 - 2016 03 31	Halton Hills Hydro Inc.	0.5475%
2011 - 2016 03 31	Hearst Power Distribution Company Limited	0.0667%

2011 - 2016 03 31	Horizon Utilities Corporation	4.0429%
2011 - 2016 03 31	Hydro 2000 Inc.	0.0390%
2011 - 2016 03 31	Hydro Hawkesbury Inc.	0.1394%
2011 - 2016 03 31	Hydro One Brampton Networks Inc.	2.8180%
2011 - 2016 03 31	Hydro One Networks Inc.	29.9788%
2011 - 2016 03 31	Hydro Ottawa Limited	5.5954%
2011 - 2016 03 31	InnPower Corporation	0.3951%
2011 - 2016 03 31	Kashechewan Power Corporation	0.0286%
2011 - 2016 03 31	Kenora Hydro Electric Corporation Ltd.	0.0989%
2011 - 2016 03 31	Kingston Hydro Corporation	0.5014%
2011 - 2016 03 31	Kitchener-Wilmot Hydro Inc.	1.6310%
2011 - 2016 03 31	Lakefront Utilities Inc.	0.1907%
2011 - 2016 03 31	Lakeland Power Distribution Ltd.	0.2906%
2011 - 2016 03 31	London Hydro Inc.	2.7308%
2011 - 2016 03 31	Midland Power Utility Corporation	0.1196%
2011 - 2016 03 31	Milton Hydro Distribution Inc.	0.5695%
2011 - 2016 03 31	Newmarket-Tay Power Distribution Ltd.	0.6607%
2011 - 2016 03 31	Niagara Peninsula Energy Inc.	0.9945%
2011 - 2016 03 31	Niagara-on-the-Lake Hydro Inc.	0.1586%
2011 - 2016 03 31	Norfolk Power Distribution Inc.	0.3495%
2011 - 2016 03 31	North Bay Hydro Distribution Limited	0.5333%
2011 - 2016 03 31	Northern Ontario Wires Inc.	0.1061%
2011 - 2016 03 31	Oakville Hydro Electricity Distribution Inc.	1.4632%
2011 - 2016 03 31	Orangeville Hydro Limited	0.2120%
2011 - 2016 03 31	Orillia Power Distribution Corporation	0.2722%
2011 - 2016 03 31	Oshawa PUC Networks Inc.	1.2283%
2011 - 2016 03 31	Ottawa River Power Corporation	0.1974%
2011 - 2016 03 31	Peterborough Distribution Incorporated	0.7132%
2011 - 2016 03 31	PowerStream Inc.	6.6383%
2011 - 2016 03 31	PUC Distribution Inc.	0.8687%
2011 - 2016 03 31	Renfrew Hydro Inc.	0.0775%
2011 - 2016 03 31	Rideau St. Lawrence Distribution Inc.	0.1120%
2011 - 2016 03 31	Sioux Lookout Hydro Inc.	0.0841%
2011 - 2016 03 31	St. Thomas Energy Inc.	0.2939%
2011 - 2016 03 31	Thunder Bay Hydro Electricity Distribution Inc.	0.8738%
2011 - 2016 03 31	Tillsonburg Hydro Inc.	0.1280%
2011 - 2016 03 31	Toronto Hydro-Electric System Limited	12.7979%
2011 - 2016 03 31	Veridian Connections Inc.	2.3525%
2011 - 2016 03 31	Wasaga Distribution Inc.	0.1799%
2011 - 2016 03 31	Waterloo North Hydro Inc.	1.0019%
2011 - 2016 03 31	Welland Hydro-Electric System Corp.	0.3879%
2011 - 2016 03 31	Wellington North Power Inc.	0.0632%
2011 - 2016 03 31	West Coast Huron Energy Inc.	0.0653%
2011 - 2016 03 31	Westario Power Inc.	0.5411%
2011 - 2016 03 31	Whitby Hydro Electric Corporation	0.8651%
2011 - 2016 03 31	Woodstock Hydro Services Inc.	0.2548%

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Program Participation & Cost Report
Glossary

#	Term	Definition
1	2011-2014+2015 Extension Legacy Framework Programs	Programs in market from 2011-2015 resulting from the April 23, 2010 GEA CDM Ministerial Directive and funded separately from 2015-2020 Conservation First Framework Programs but whose savings in 2015 are attributed towards the 2015-2020 Conservation First Framework target.
2	2015-2020 Conservation First Framework Programs	Programs in market from 2015-2020 resulting from the March 31, 2014 CFF Ministerial Directive and funded separately from 2011-2014+2015 Extension Legacy Framework Programs.
3	Allocated Target	Each LDC's assigned portion of the Province's 7 TWh Net 2020 Annual Energy Savings Target of the 2015-2020 Conservation First Framework.
4	Allocated Budget	Each LDC's assigned portion of the Province's $ 1.835 billion CDM Plan Budget of the 2015-2020 Conservation First Framework.
5	Province-Wide Program	Programs available to all LDCs to deliver and that are consistent across the province.
6	Regional Program	Programs designed by LDCs to serve their region and approved by the IESO.
7	Local Program	Programs designed by LDCs to serve their communities and approved by the IESO.
8	Pilot Program	A program pilot that may achieve energy or demand savings and is funded extraneous to an LDC's CDM Plan Budget.
9	Initiative	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup) from the 2011-2014+2015 Extension Legacy Framework.
10	Program	A Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup) from the 2015-2020 Conservation First Framework.

11	Activity	The number of projects.
12	Unit	For a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).
13	Forecast	LDC's forecast of activity, savings, expenditures and cost effectiveness as indicated in each LDC's submitted CDM Plan Cost Effectiveness Tools.
14	Actual	The IESO determined final results of activity, savings, expenditures and cost effectiveness.
15	Progress	A comparison of Actuals versus Forecasts.
16	Full Cost Recovery Progress	For a given year, the percentage calculated by dividing: a) the sum of verified electricity savings for all years of the term up to and including the applicable year for all Programs that receive full cost recovery funding, by b) the Cumulative FCR Milestone, multiplied by 100%, as specified in Schedule A of the Energy Conservation Agreement.
17	Reported Savings	Savings determined by the LDC: 1) for prescriptive projects/programs: calculating quantity x prescriptive savings assumptions; and 2) for engineered or custom program projects/programs: calculated using prescribed methodologies.
18	Verified Savings	Savings determined by the IESO's evaluation, measurement and verification that may adjust reported savings by the realization rate.
19	Gross Savings	Savings determined as either: 1) program activity multiplied by per unit savings assumptions for prescriptive programs; or 2) reported savings multiplied by the realization rate for engineered or custom program streams.
20	Net Savings	The peak demand or energy savings attributable to conservation and demand management activities net of free-riders, etc.
21	Realization Rate	A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.
22	Net-to-Gross Adjustment	The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover.
23	Free-ridership	The percentage of participants who would have implemented the program measure or practice in the absence of the program.

24	Spillover	Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.
25	Incremental Savings	The new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.
26	First Year Savings	The peak demand or energy savings that occur in the year it was achieved (includes resource savings from only new program activity).
27	Annual Savings	The peak demand or energy savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).
28	Demand Savings	Demand savings attributable to conservation and demand management activities.
29	Energy Savings	Energy savings attributable to conservation and demand management activities.
30	Administrative Expenses	Costs incurred in the delivery of a program related to labour, marketing, third-party expenses, value added services or other central services.
31	Participant Incentives	Costs incurred in the delivery of a program related to incenting participants to perform peak demand or energy savings.
32	Total Expenditure	The sum of Administrative Expenses and Participant Incentives
33	Total Resource Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on the total costs of the program including both participants' and utility's costs.
34	Program Administrator Cost Cost Effectiveness Test	A cost effectiveness test that measures the net cost of CDM based on costs incurred by the program administrator, including incentive costs and excluding net costs incurred by the participant.
35	Levelized Unit Energy Cost Cost Effectiveness Test	A cost effectiveness test that normalizes the costs incurred by the program administrator per unit of energy or demand reduced.

Appendix B – Most Recent federal and provincial tax returns

KPMG

KPMG LLP
1800 - 150 Elgin Street
Ottawa ON K2P 2P8
Canada
Telephone (613) 212-5764
Fax (613) 212-2896

PRIVATE AND CONFIDENTIAL

Jeffrey Roy
Chief Financial Officer
Ottawa River Power Corporation
283 Pembroke Street W
Pembroke ON K8A 5N5

May 28, 2021

Dear Roy:

Subject: Ottawa River Power Corporation - Corporate Income Tax Returns

We have enclosed the corporate income tax return(s) (the "Returns") of Ottawa River Power Corporation (the “Company”) for the period ended December 31, 2020.

- ☑ T2 – *Corporation Income Tax Return* - EXEMPT
- ☑ T183 - *Information Return for Corporations Filing Electronically* (Federal - to be e-filed with CRA) - EXEMPT
- ☑ T2 – *Corporations Income Tax Return* (to be filed with Ministry of Finance) - PILS
- ☑ Instalment Schedule
- ☑ Client copy for your records

We have prepared these Returns based on our understanding of and reliance upon the facts, data, materials, assumptions and other information (collectively, the ”Information”) provided to us by the Company and/or its representatives, and we have not independently investigated or verified the accuracy or completeness of such Information. We accept no responsibility or liability for any errors attributable to our reliance upon inaccurate or incomplete Information. We recommend that you carefully review the Returns in their entirety to ensure that all of the relevant Information is correctly and completely disclosed.

When you are satisfied that the Returns are in order they must be filed (electronically or in paper format) with the respective taxing authorities by the due date (as set out in the following instructions) if late filing penalties are to be avoided or minimized, or if losses are carried back to a prior taxation year. One copy of each Return should be retained for your records (the "Client Copy") and the remaining copies should be completed by an authorized signing officer of the Company and filed as described below.

FOREIGN PROPERTY

The information return, which reports the Company's specified foreign property, is Form T1135 - *Foreign Income Verification Statement*. Form T1135 should be completed if at any time during 2020 the total cost of all specified foreign property the Company owned or held a beneficial interest in was more than Cdn$100,000.

According to the information you have provided to us, the Company did not hold specified foreign property at any time in 2020 with a total cost of more than Cdn$100,000. As such, we have **not** marked an X in box 259 on page 3 of your return and **we have not completed the Form T1135**. If the information on specified foreign property is incorrect, please let us know immediately.

The Form T1135 is due by **June 30, 2021**. The implications of late filing and/or failure to properly report specified foreign property on the Form T1135 and failure to report income from a specified foreign property on your income tax return are substantial. They include significant penalties and an increase to the normal reassessment period by an additional 3 years. Further, the reassessment period extension would impact otherwise statute-barred tax years and would impact the entire income tax return, not just the foreign income and reporting sections.

DUE DATE OF RETURNS AND PAYMENTS

All returns must be filed with the respective taxing authorities by June 30, 2021 if late filing penalties are to be avoided. We recommend the returns be sent by registered mail and the mailing receipt be kept on file in order to have evidence of the date of filing.

Any balances owing must be remitted as soon as possible if interest charges are to be minimized.

T2 – T183 – INFORMATION RETURN FOR CORPORATIONS FILING ELECTRONICALLY (FEDERAL-EXEMPT)

In order for us to electronically file the Company's corporate exempt income tax return, a signed copy of Form T183CORP – *Information Return for Corporations Filing Electronically* must be returned to us. Please note that we will not electronically file the Company's corporate income tax return until we receive the signed Form T183 Corp.

The Form T183CORP – *Information Return for Corporations Filing Electronically* includes information from your Company's income tax return and all applicable schedules.

Signature

☞ Form T183CORP – *Information Return for Corporations Filing Electronically* should be completed and signed

No amount is payable for the **2020** taxation year.

Mailing

☒ One copy of the signed Form T183 Corp should be returned to KPMG by fax at (613) 212-2896, as soon as possible, no later than June 30, 2021, in order to have the Company's Return filed on or before the due date for filing. **We will not electronically file the Return until we receive a copy of the signed T183CORP**. The Form T183CORP must **not** be sent to the CRA.

T2 – *CORPORATION INCOME TAX RETURN* - MINISTRY OF FINANCE

Signature

☞ Form T2, the certification section on page 9 should be completed and signed.

Enclosure

A cheque in the amount of **$28,440** made payable to the Minister of Finance should be attached to the return for the **2020** taxation year. You should write the company's tax account number on the back of the cheque and the taxation year for which the payment is made. Alternatively, you may make the payment at any branch of a chartered bank.

No amount is payable for the **2020** taxation year.

Mailing

☒ One copy of the Return and one copy of the Company's financial statements must be **received** by The Ministry of Finance, HYDRO PIL DIVISION, PO Box 620, 33 King Street West, Oshawa, ON, L1H 8E9 no later than **June 30, 2021.** For greater certainty, KPMG will not be mailing this Return.

NOTICES OF ASSESSMENT

If your Company receives a Notice of Assessment that does not agree with the returns prepared by us, please contact us so that we can determine whether any action should be taken. The Company has only 90 days (180 days in the case of Ontario) from the date of mailing of the Assessment in which to object. Failure to respond within the prescribed time limit will cause the Company to lose its right to object to the Assessment.

Any balances owing must be remitted by the due date (as set out in the Filing Instructions), or as soon as possible, if interest charges are to be minimized.

GENERAL RATE INCOME POOL ("GRIP")

Shareholders receiving eligible dividends as compared to non-eligible dividends, are subject to a reduced rate of income tax. Eligible dividends are paid out of the Company's GRIP balance, which at December 31, 2020 is estimated to be $4,332,230. The supporting calculation is summarized in Schedule 53 of the federal corporate tax return.

In addition, designation of eligible dividends is required, with each shareholder recipient being formally notified in writing at time of payment.

The Company did not designate the payment of an eligible dividend for the current taxation year.

INSTALMENTS

We have prepared and enclose an estimate of tax instalments as applicable for the Company for the taxation year ending on December 31, 2021. The amounts were computed with reference to the Company's taxable income and taxes payable for prior years.

If during the year it is evident that the taxable income or taxable capital for the current year will be substantially less than for the previous taxation year, your instalments may be recalculated. Overpaid instalments may, in certain circumstances, be transferred to other accounts or applied to other liabilities such as payroll withholdings. Please call your KPMG advisor in order that we may determine what course of action should be taken.

In order to avoid interest charges, the tax authorities must receive the instalment payments no later than the date indicated on the attached schedule.

If you have any questions concerning these returns, or if we may be of any further assistance, please feel free to contact us.

Yours truly,

Kevin Bennett

Kevin Bennett, CPA, CA, CFP
Partner – Tax

Enclosure

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2021-12-31

Business number 87176 4072 RC0001

The following is a list of instalments payable for the current taxation year, and the last column indicates the instalments payable to the Canada Revenue Agency (CRA). The instalments must be paid on each of the dates indicated below, otherwise non-deductible interest might be charged.

Instalment payments can be made using one of the following methods:

- electronically, using your online or telephone banking services;
- online, using the CRA's *My Payment* service, at **canada.ca/cra-my-payment**;
- by setting up a pre-authorized debit agreement, in *My Business Account*, at **canada.ca/my-cra-business-account**;
- in person, at a Canadian financial institution, **by presenting the appropriate remittance voucher** with your payment.

You can also mail a cheque or a money order payable to the Receiver General of Canada, **accompanied by the appropriate remittance voucher**, to Canada Revenue Agency, P.O. Box 3800, Station A, Sudbury ON P3A 0C3.

Do you want to calculate the tax instalments according to the extended payment date (COVID-19)?* ☐ Yes ☒ No

* The answer to this question is **Yes** when at least one of the dates entered in the **Monthly instalment workchart** or the **Quarterly instalment workchart** sections is after March 17, 2020, and before September 30, 2020.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2021-01-31	2,370		16,640	-14,270	
2021-02-28	2,370		16,640	-28,540	
2021-03-31	2,370		16,640	-42,810	
2021-04-30	2,370		16,640	-57,080	
2021-05-31	2,370		16,000	-70,710	
2021-06-30	2,370			-68,340	
2021-07-31	2,370			-65,970	
2021-08-31	2,370			-63,600	
2021-09-30	2,370			-61,230	
2021-10-31	2,370			-58,860	
2021-11-30	2,370			-56,490	
2021-12-31	2,370			-54,120	
Instalment (COVID-19)					
Totals	28,440		82,560		-54,120

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 87176 4072 RC0001

Corporation's name
002 Ottawa River Power Corporation

Address of head office
Has this address changed since the last time we notified? . . . . 010 Yes [ ] No [X]
If **yes**, complete lines 011 to 018.
011 283 Pembroke Street W
012
City
015 Pembroke
Province, territory, or state
016 ON
Country (other than Canada)
017
Postal or ZIP code
018 K8A 5N5

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
022
023
City
025
Province, territory, or state
026
Country (other than Canada)
027
Postal or ZIP code
028

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		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		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		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	X	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)

	Line	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		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

	Line	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.

Line	Product/service	Line	%
284	Energy	285	100.000 %
286		287	%
288		289	%

	Line	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		107,318	A
Deduct:				
Charitable donations from Schedule 2	311			
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		►		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			107,318	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		107,318	
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	107,318	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	107,318	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 *** 14,798 D / 11,250 = 657,689 E

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** 417 ______ – 50,000 = ______ F

Amount C 500,000 / 100,000 x Amount F ______ = ______ G

The greater of amount E and amount G 422 657,689 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			107,318	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")			107,318	H
General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 %			13,951	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			107,318	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)		107,318 K x 30 2/3 % =	32,911	L
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9)			16,098	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

Description	
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)	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")	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	40,781 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	107,318 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)	107,318 ▶	107,318	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)		40,781	I

Deduct:

Small business deduction from line 430 on page 4			J
Federal tax abatement	608	10,732	
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	13,951	
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		24,683 ▶	24,683 K

Part I tax payable – Amount I **minus** amount K	16,098 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	16,098
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		16,098

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	12,342
Total tax payable	770	28,440 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	
Total credits	890	B

Balance (amount A **minus** amount B) 28,440

Refund code 894 1 Refund

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 28,440

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 A8340

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Roy (Last name) 951 Jeffrey (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 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 (613) 732-3687 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

Corporation's name	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

General Index of Financial Information

Notes to the financial statements

Ottawa River Power Corporation (the "Corporation") was incorporated in accordance with the
provincial government's Electricity Act, 1998 under the Business Corporations Act (Ontario) on
April 22, 1999. Ottawa River Power Corporation is the successor to the former Pembroke Hydro
Electric Commission ("Pembroke Hydro"), the Town of Mississippi Mills Public Utilities
Commission ("Almonte Hydro"), the Township of Killaloe, Hagarty & Richards Hydro Electric
Commission ("Killaloe Hydro") and the Beachburg Hydro System ("Beachburg Hydro").
The shareholders of the Corporation are the City of Pembroke (78.4%), the Town of Mississippi
Mills (15.9%), the Township of Killaloe-Hagarty-Richards (3.0%) and the Township of WhitewaterRegion (2.7%).
The Corporation is the electric distribution utility for residents of the City of Pembroke, the Town
of Mississippi Mills (Almonte Ward), the Township of Killaloe and the Village of Beachburg under
a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB
and adjustments to the Corporation's distribution and power rates require OEB approval.1. Basis of presentation:
(a) Statement of compliance:
These financial statements have been prepared by management on a going-concern basis in
accordance with International Financial Reporting Standards ("IFRS") as issued by the
International Accounting Standards Board ("IASB") and interpretations as issued by the
International Financial Reporting Interpretations Committee ("IFRIC") of the IASB.
The financial statements were authorized for issue by the Board of Directors on April 22,2021.
(b) Basis of presentation:
The financial statements have been prepared on the historical cost basis.
(c) Functional and presentation currency:
These financial statements are presented in Canadian dollars, which is the Corporation's
functional currency. All financial information presented has been rounded to the nearestdollar.
(d) Use of estimates and judgments:
The preparation of financial statements in compliance with IFRS requires management to
make certain critical accounting estimates. It also requires management to exercise judgment
in applying the Corporation's accounting policies. The areas involving a higher degree of
judgment, complexity, or areas where assumptions and estimates are significant to thefinancial statements are disclosed in note 3.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
1. Basis of presentation (continued):

General Index of Financial Information
Notes to the financial statements

(e) Explanation of activities subject to rate regulation:
Ottawa River Power Corporation, as an electricity distributor, is both licensed and regulated
by the OEB which has a legislative mandate to oversee various aspects of the electricity
industry. The OEB exercises statutory authority through setting or approving all rates charged
by the Corporation and establishing standards of service for the Corporation's customers.
The OEB has broad powers relating to licensing, standards of conduct and service and the
regulation of rates charged by the Corporation and other electricity distributors in Ontario.
The Ontario government enacted the Energy Competition Act, 1998, to introduce competition
to the Ontario energy market. Rates are set by the OEB on an annual basis for May 1 toApril 30.
Regulatory risk
Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a
regulatory regime that imposes conditions that restrict the electricity distribution business
from achieving an acceptable rate of return that permits financial sustainability of its
operations including the recovery of expenses incurred for the benefit of other market
participants in the electricity industry such as transition costs and other regulatory assets. All
requests for changes in electricity distribution charges require the approval of the OEB.Recovery risk
Regulatory developments in Ontario's electricity industry, including current and possible
future consultations between the OEB and interested stakeholders, may affect distribution
rates and other permitted recoveries in the future. The Corporation is subject to a cost of
service regulatory mechanism under which the OEB establishes the revenues required (i) to
recover the forecast operating costs, including depreciation and amortization and income
taxes, of providing regulated service, and (ii) to provide a fair and reasonable return on utility
investment, or rate base. As actual operating conditions may vary from
forecast, actualreturns achieved can differ from approved returns.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies:
The preparation and presentation of financial statements can be significantly affected by the
accounting policies selected by the Corporation. The financial statements reflect the following
significant accounting policies, which are an integral part of understanding them.
The accounting policies set out below have been applied consistently to all

periods presented inthese financial statements unless otherwise indicated.
(a) Regulatory deferral accounts:
Regulatory deferral account debit balances represent future revenues associated with certain
costs incurred in the current period or in prior period(s) that are expected to be recovered
from consumers in future periods through the rate-setting process. Regulatory deferral
account credit balances are associated with the collection of certain revenue earned in the
current period or prior period(s) that are expected to be returned to consumers in future
periods through the rate-setting process. Regulatory deferral account balances can arise
from differences in amounts collected from customers (based on regulated rates) and the
corresponding cost of non-competitive electricity service incurred by the Corporation in the
wholesale market administered by the Independent Electricity System Operator (the "IESO")
after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying
the Electricity Act (the "EA") and deferred in anticipation of their future
recovery or expense inelectricity distribution service charges.
Explanation of recognized amounts
Regulatory deferral account balances are recognized and measured initially and
subsequently at cost. They are assessed for impairment on the same basis as
othernonfinancial assets as described below.
Management continually assesses the likelihood of recovery of regulatory deferral accounts.
If recovery through future rates is no longer considered probable, the amounts would be
charged to the results of operations in the period that the assessment is made.(b) Revenue recognition:
The Corporation recognizes revenue from contracts with customers when it transfers control
over a product or service to a customer either over time or at a point in time. Revenue is
measured at the consideration received or receivable, excluding sales taxes and other
amounts collected on behalf of third parties. Revenue is comprised of sales and distribution
of energy, pole use rental, collection charges, administrative services and
othermiscellaneous revenue.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(b) Revenue recognition (continued):
Sale and distribution of energy
The Corporation is licensed by the OEB to distribute electricity. 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 has determined that
they are acting
as a principal for the electricity distribution and, therefore, have
presented the electricityrevenues on a gross basis.
Revenues from the sale and distribution of electricity is recognized over
time as electricity isdelivered to the customer, as measured by meter
readings.
Other Revenues
Other revenues, which include revenues from pole use rental, collection
charges,
administrative services and other miscellaneous revenues are recognized over
time as the
services are provided, except for revenue from certain account-related
charges, which isrecognized at a point in time.
Where the Corporation has an ongoing obligation to provide services, revenues
arerecognized over time as the services are performed. Revenue earned for
service workrelated to distribution operations is recognized over time as the
corresponding costs are
recognized proportionately with the degree of completion of the services
under contract.Amounts billed in advance are recognized as deferred revenue.
Contributions in aid of construction
Certain assets may be acquired or constructed with financial assistance in
the form of
contributions from developers when the estimated revenue is less than the
cost of providing
service or where special equipment is needed to supply specific requirements.
Capitalcontributions from developers are recognized as deferred revenue and
amortized into
revenue from other sources at an equivalent rate to that used for the
depreciation of therelated property, plant and equipment.
(c) Cash:
Cash includes cash on hand with financial institutions.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(d) Financial instruments:
Financial assets and financial liabilities are recognized when the
Corporation becomes aparty to the contractual provisions of the instrument.
Accounts receivable and unbilled energy revenue are initially measured at the
transaction
price. All other financial assets and financial liabilities are initially
measured at fair value.
The Corporation determines the classification of its financial assets on the
basis of both the
business model for managing the financial assets and the contractual cash flow
characteristics of the financial asset. Financial assets are not reclassified
subsequent to their
initial recognition unless the Corporation changes its business model for
managing financialassets.

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Notes to the financial statements

A financial asset is measured at amortized cost if it is held within a
business model whose
objective is to hold assets to collect contractual cash flows, and its
contractual terms give rise
on specified dates to cash flows that are solely payments of principal and
interest on theprincipal amount outstanding.
Financial assets are classified as amortized cost. These include cash,
accounts receivable,
unbilled energy revenue, and due from Ottawa River Energy Solutions.
Subsequent to initial
recognition, financial assets at amortized cost are measured using the
effective interestmethod, less any impairment.
The Corporation measures a loss allowance for expected credit losses ("ECLs")
on financial
assets measured at amortized cost. The Corporation measures loss allowances
for accounts
receivable and unbilled revenue via a simplified approach as permitted by
IFRS 9, at an
amount equal to lifetime ECL. When determining whether the credit risk of a
financial asset
has increase, the Corporation performs a quantitative and qualitative
analysis based on the
Corporation's historical experience and forward-looking information.
Loss allowances for financial assets measured at amortized cost are deducted
from the gross
carrying amount of the assets. The gross carrying amount of a financial asset
is written off tothe extent there is no realistic prospect of recovery.
The Corporation determines the classification of its financial liabilities at
initial recognition.
The Corporation's financial liabilities are classified as amortized cost.
These include accounts
payable and accrued liabilities, due to Ottawa River Energy Solutions,
customer deposits,loan payable, and long-term debt.
Financial liabilities at amortized cost are measured using the effective
interest method.11
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(e) Customer deposits:
Customers may be required to post security to obtain electricity or other
services, which are
refundable. Where the security posted is in the form of cash, these amounts
are recorded in
the accounts as deposits. Deposits to be refunded to customers within the
next fiscal year are
classified as a current liability. Interest rates paid on customer deposits
are based on theBank of Canada's prime business rate less 2%.
(f) Property, plant and equipment:
Recognition and measurement
Property, plant and equipment ("PP&E") are recognized at cost less accumulated
depreciation and accumulated impairment losses. Cost includes the purchase
price and
directly attributable cost of acquisition or construction required to bring
the asset to the
location and condition necessary to be capable of operating in the manner

intended by theCorporation, including eligible borrowing costs.
Depreciation of PP&E is recorded in the statement of comprehensive income on a straightline
basis over the estimated useful life of the related asset. The estimated useful lives,
residual values and amortization methods are reviewed at the end of each annual reporting
period, with the effect of any changes in estimate being accounted for on a prospective basis.The estimated useful lives are as follows:

Asset Useful life
Substation and buildings 30 to 60 years
Poles, towers and fixtures 25 to 45 years
Overhead conductors and devices 25 to 60 years
Underground conduit 25 to 50 years
Underground conductors and devices 25 to 40 years
Services 3 to 25 years

Major spare parts such as spare transformers and other items kept as standby/back up
equipment are accounted for as PP&E since they support the corporation's distribution
system reliability. No amortization is recorded on these items until they are put into service.Contributions in aid of construction
When an asset is received as a capital contribution, the asset is initially recognized at its fair
value, with the corresponding amount recognized as contributions in aid of construction.12

OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020

2. Significant accounting policies (continued):
(f) Property, plant and equipment (continued):
Gains and losses on disposal
Gains and losses on disposal of an item of property, plant and equipment are determined by
comparing the net proceeds from disposal with the carrying amount of the asset, and are
included in the statement of income and comprehensive income when the asset is disposed.
When an item of property, plant and equipment with related contributions in aid of
construction is disposed, the remaining contributions are recognized in full in the statement ofincome and comprehensive income.
(g) Borrowing costs:
The Corporation capitalizes interest expenses and other finance charges directly relating to
the acquisition, construction or production of assets that take a substantial period of time to
get ready for its intended use. Capitalization commences when expenditures are beingincurred, borrowing costs are being incurred and activities that are necessary to prepare the
asset for its intended use or sale are in progress. Capitalization will be suspended during
periods in which active development is interrupted. Capitalization should cease when
substantially all of the activities necessary to prepare the asset for its intended use or saleare complete.

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Notes to the financial statements

(h) Intangible assets:
Land rights
Payments to obtain rights to access land ("land rights") are classified as intangible assets.
These include payments made for easements, right of access and right of use over land for
which the Corporation does not hold title. Land rights are measured at cost less accumulatedamortization and accumulated impairment losses.
Computer software
Computer software that is acquired or developed by the Corporation, including software that
is integral to the functionality of equipment purchased, which has finite useful lives, is
measured at cost less accumulated amortization and accumulated impairment losses.Amortization
Amortization is recognized in profit or loss on a straight-line basis over the estimated useful
lives of intangible assets, other than goodwill, from the date that they are available for use.
Half of a year's amortization is taken for the first year. Amortization of useful lives for thecurrent and comparative years are:
Asset Useful life
Land rights 25 to 30 years
Computer software 3 years
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(i) Impairment of non-financial assets:
The Corporation conducts annual internal assessments of the values of equipment to
determine whether there are events or changes in circumstances that indicate that their
carrying amount may not be recoverable. Where carrying value exceeds its recoverable
amount, which is the higher of value in use and fair value less costs to sell, the asset is
written down accordingly. Where it is not possible to estimate the recoverable amount of an
individual asset, the impairment test is carried out on an asset's cash-generating unit, which
is the lowest group of assets to which the asset belongs for which there are separately
identifiable cash inflows that are largely independent of the cash inflows from other assets.
An impairment loss is charged to the statement of income and comprehensive income,except to the extent it reverses gains previously recognized in other comprehensive income.(j) Employee future benefits:
Pension plan
The employees of the Corporation participate in the Ontario Municipal Employees Retirement
System ("OMERS"). The Corporation also makes contributions to the OMERS plan on behalfof its employees. The plan has a defined benefit option at retirement
available to some

employees, which specifies the amount of the retirement benefit plan to be received by the
employees based on length of service and rates of pay. However, the plan is accounted for
as a defined contribution plan as insufficient information is available to account for the plan as
a defined benefit plan. The contribution payable in exchange for services rendered during a
period is recognized as an expense during that period. The Corporation is only one of a
number of employers that participates in the plan and financial information provided to the
Corporation on the basis of the contractual agreements is usually insufficient to measure the
Corporation's proportionate share in the plan's assets and liabilities for defined benefitaccounting requirements.
Post-employment defined benefit plan
A defined benefit plan is a post-employment benefit plan other than a defined contribution
plan. The Corporation's net obligation on behalf of its retired employees unfunded life
insurance benefits is calculated by estimating the amount of future benefits that are expectedto be paid out discounted to determine its present value.
The calculation is performed by a qualified actuary using the projected unit credit method at
least every third year or when there are significant changes to workforce.
Defined benefit obligations are measured using the projected unit credit method discounted
to its present value using yields available on high quality corporate bonds that have maturitydates approximating the terms of the liabilities.
Remeasurements of the defined benefit obligation are recognized directly within equity in
other comprehensive income. The remeasurements include actuarial gains and losses.14
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(j) Employee future benefits (continued):
Post-employment defined benefit plan (continued)
Service costs are recognized in operating expenses and include current and past servicecosts as well as gains and losses on curtailments.
Net interest expense is recognized in finance costs and is calculated by applying the discount
rate used to measure the defined benefit obligation at the beginning of the annual period to
the balance of the net defined benefit obligation, considering the effects of benefit payments
during the period. Gains or losses arising from changes to defined benefits or plancurtailment are recognized immediately in the statement of income and comprehensive
income. Settlements of defined benefit plans are recognized in the period in which thesettlement occurs.
Other long-term service benefits
Other employee benefits that are expected to be settled wholly within 12 months after the end

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Notes to the financial statements

of the reporting period are presented as current liabilities. Other employee benefits that are
not expected to be settled wholly within 12 months after the end of the reporting period are
presented as non-current liabilities and calculated using the projected unit credit method and
then discounted using yields available on high quality corporate bonds that have maturity
dates approximating to the expected remaining period to settlement.
(k) Payments in lieu of taxes payable:
The Corporation is a Municipal Electricity Utility ("MEU") for purposes of the payments in lieu
of taxes ("PILs") regime contained in the Electricity Act, 1998. As a MEU, the Corporation is
exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).
Under the Electricity Act, 1998, the Corporation is required to make, for each taxation year,
PILs to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001.
These payments are calculated in accordance with the rules for computing taxable income
and taxable capital and other relevant amounts contained in the Income Tax Act (Canada)
and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and relatedregulations.
Current and deferred tax
Provision in lieu of taxes is comprised of current and deferred tax. Current tax and deferred
tax are recognized in total income and other comprehensive income except to the extent that
it relates to items recognized directly in equity or regulatory deferral account balances (note10).
Current PILs are recognized on the taxable income or loss for the current year plus any
adjustment in respect of previous years. Current PILs are determined using tax rates and tax
laws that have been enacted or substantively enacted by the year-end date.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(k) Payments in lieu of taxes payable (continued):
Deferred tax assets and liabilities are recognized where the carrying amount of an asset or
liability differs from its tax base. The amount of the deferred tax asset or liability is measured
at the amount expected to be recovered from or paid to the taxation authorities. This amount
is determined using tax rates and tax laws that have been enacted or substantively enacted
by the year-end date and are expected to apply when the liabilities/(assets)
aresettled/(recovered). The Corporation recognized deferred tax arising from
temporarydifference on regulatory deferral account balances.
Recognition of deferred tax assets for unused tax losses, tax credits and

deductible
temporary differences is restricted to those instances where it is probable that future taxable
profit will be available against which the deferred tax asset can be utilized.
At the end of each reporting period, the Corporation reassesses both recognized and
unrecognized deferred tax assets. The Corporation recognizes a previously unrecognized
deferred tax asset to the extent that it has become probable that future
taxable profit willallow the deferred tax asset to be recovered.
(l) Finance income and finance costs:
Finance income is comprised of interest income on funds invested. Interest income is
recognized as it accrues in the statement of income and comprehensive income,
using theeffective interest method.
Finance cost is comprised of interest payable on debt.
(m) Inventory:
Cost of inventory is comprised of direct materials, which typically consists of distribution
assets not deemed as major spares, unless purchased for specific capital projects in process
or as spare units. Costs, after deducting rebates and discounts, are assigned to individual
items of inventory on the basis of weighted average cost. Decommissioned assets that are
transferred to inventory are tested for impairment once they are removed from service and
placed in inventory. Inventory is recognized at the lower of cost and net realizable value. Net
realizable value is the estimated selling price in the ordinary course of business less the
estimated costs of completion and the estimated costs necessary to make the sale.(n) Leases:
At the inception of the contract, the Corporation assesses whether the contract is, or
contains, a lease based on whether the contract conveys the right to control the use of an
identified asset for a period of time, in exchange for consideration.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(n) Leases (continued):
The corporation recognizes a right-of-use ("ROU") assets and a lease liability at the lease
commencement date. ROU assets are initially measured at cost and subsequently carried at
cost less accumulated depreciation and impairments, if any. The initial cost of an ROU asset
equals the amount of the initial measurement of the corresponding lease liability, plus any
initial direct costs incurred to bring the assets into operation.
Lease liabilities are initially measured at the present value of lease payments that are not
paid at the commencement date. The lease payments are discounted using the

rate implicitin the lease, or, if that rate cannot be readily determined, the Corporation's incremental
borrowing rate which reflects the Corporation's ability to borrow money over a similar term,
for an asset of similar value to the underlying asset, similar security or in a similar economic
environment. Variable lease payments that do not depend on an index or rate are notincluded in the measurement of the lease liability.
Lease liabilities are 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 Company changes its
assessment of whether it will exercise a purchase, extension or termination option.
When a lease liability is remeasured in this way, a corresponding adjustment is made to the
carrying amount of the ROU asset, or is recorded in profit or loss if the carrying amount of the
ROU asset has been reduced to zero. Payments under lease liabilities are apportioned
between interest expense and a reduction of the outstanding lease liability.
Where the Corporation is reasonably certain it will obtain ownership of the ROU asset before
the end of the lease term, the asset is depreciated over its useful life on a straight-line basis.
Otherwise, depreciation is calculated over the shorter period of the lease term and the asset's
useful life. The lease term includes periods covered by an option to extend if the Corporationis reasonably certain to exercise that option.
The Corporation has elected to apply the practical expedient not to recognize ROU assets
and lease liabilities for short-term leases that have a lease term of 12 months or less and
leases of low-value assets. The lease payments associated with these leases arerecognized as an expense on a straight-line basis over the lease term.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
3. Use of estimates and judgments:
The Corporation makes certain estimates and assumptions regarding the future. Estimates and
judgments are continually evaluated based on historical experience and other factors, including
expectations of future events that are believed to be reasonable under the circumstances. In the
future, actual experience may differ from these estimates and assumptions. The estimates and
assumptions that have a significant risk of causing a material adjustment to the carrying amounts
of assets and liabilities within the next financial year are discussed below.
Employee future benefits

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The cost of post-employment life insurance benefits are determined using actuarial valuations. An actuarial valuation involves making various assumptions. Due to the complexity of the valuation, the underlying assumptions and its long term nature, post-employment life insurance benefits are highly sensitive to changes in these assumptions. All assumptions are reviewed at each reportingdate.

Payments in lieu of taxes payable

The Corporation is required to make payments in lieu of tax calculated on the same basis as income taxes on taxable income earned and capital taxes. Significant judgment is required in determining the provision for income taxes. There are many transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Corporation recognizes liabilities for anticipated tax audit issues based on the Corporation's current understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred tax provisions in the period in which such determination is made.

Accounts receivable impairment

In determining the allowance for doubtful accounts, the Corporation considers historical loss experience of account balances based on the aging and arrears status of accounts receivable balances, observable changes in national or local economic conditions that correlate with default on receivables, financial difficulty of the borrower, and it becoming probable that the borrower willenter bankruptcy or financial re-organization.

Useful lives of depreciable assets

Depreciation expense is calculated based on estimates of the useful lives of equipment. Management estimates the useful lives of the various types of assets using assumptions and estimates of life characteristics of similar assets based on a long history of experience.18

OTTAWA RIVER POWER CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2020

4. Accounts receivable:

	2020	2019
Residential and commercial energy and rentals	$ 2,053,023	$ 2,167,669
Work at customers premises	175,202	151,022
Employee purchases	826	-
HST recoverable	220,055	144,860
Other miscellaneous receivables	458,329	697,229
Due from related party	30,303	53,646
	2,937,738	3,214,426
Allowance for doubtful accounts	(179,775)	(99,382)
	$ 2,757,963	$ 3,115,044

Due to their short-term natures, the carrying amounts of the various components of accountsreceivable approximate their fair values.

Corporation's name	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

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Notes to the financial statements

5. Related party transactions:
(a) The ultimate parent:
The common shares of Ottawa River Power Corporation are owned by the City of Pembroke,
the Town of Mississippi Mills, the Township of Killaloe-Hagarty-Richards and the Township of
Whitewater Region, which all constitute local governments. Consequently, the Corporation is
exempt from some of the general disclosure requirements of IAS 24 with
relation totransactions with government-related parties, and has applied the
government-relateddisclosure requirements.
(b) Transactions with related parties:
The following summarizes the Corporation's related party transactions for the year. These
transactions are in the normal course of operations and are measured at the exchange value
(the amount of consideration established and agreed to by the related parties).19
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
5. Related party transactions (continued):
(b) Transactions with related parties (continued):
Ottawa River Energy Solutions Inc.
The Corporation has agreed to provide operating capital to Ottawa River Energy Solutions
Inc. Advances are due on demand. Interest on the operating loan is charged at the Royal
Bank of Canada prime rate, calculated semi-annually and payable on April 30. The loan
agreement does not provide for interest on payable amounts. The interest calculation
commenced January 1, 2003. At December 31, 2020, no amounts have been drawn
on theoperating loan (2019 - $Nil).
The Corporation provides services to Ottawa River Energy Solutions Inc., at cost. A summary
of amounts charged by the Corporation to the Ottawa River Energy Solutions
Inc. are asfollows:
2020 2019
Labour on customer premises $ 423,426 $ 610,658
Administration services 16,636 62,835
Rent and Service Charges 29,554 29,627
$ 469,616 $ 703,120
Included in the statement of income and comprehensive income is fibre services of $24,240
(2019 - $24,240) and solar generation of $34,578 (2019 - $17,983) paid to
Ottawa RiverEnergy Solutions Inc.
At December 31, 2020, the Corporation has an amount of $Nil due from (2019 -
$339,312due from) Ottawa River Energy Solutions Inc. The Corporation also has accounts payable
and accrued liabilities of $17,900 (2019 - $35,183) due to Ottawa River Energy Solutions Inc.
and accounts receivable include $30,303 (2019 - $53,646) due from Ottawa River Energy
Solutions Inc. Ottawa River Energy Solutions Inc. is affiliated by virtue of
common ownership.20

Corporation's name	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

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Notes to the financial statements

OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
5. Related party transactions (continued):
(b) Transactions with related parties (continued):
Corporation of the City of Pembroke
The Corporation provides electricity and services to the principal shareholder, the City of
Pembroke. Electrical energy is sold to the City at the same prices and terms as other
electricity customers consuming equivalent amounts of electricity. A summary of amountscharged by the Corporation to the City of Pembroke are as follows:
2020 2019
Electrical energy $ 875,341 $ 953,013
Merchandising Jobbing 44,420 44,512
$ 919,761 $ 997,525
At December 31, 2020, accounts payable and accrued liabilities include $80,732 (2019 -
$45,799) due to the City of Pembroke and accounts receivable include $81,938
(2019 -$104,484) due from the City of Pembroke.
Dividends in the amount of $Nil (2019 - $193,101) have been paid to the City of Pembroke.
Property taxes and water and sewer charges paid to the City of Pembroke amounted to
$23,172 (2019 - $12,307). The Corporation incurred interest on the financing provided by theCity of Pembroke in the amount of $234,426 (2019 - $234,426).
(c) Key management personnel compensation:
The key management personnel of the Corporation has been defined as members of itsboard of directors and executive management team members.
2020 2019
Board of directors' fees $ 38,483 $ 38,805
Short-term employment benefits and salaries 572,256 578,858
Post-employment benefits 59,308 59,582
$ 670,047 $ 677,245
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
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6. Inventory:
Inventory consists of maintenance and construction materials amounting to
$430,126 (2019 - $491,988).7. Property, plant and equipment:
Poles, Overhead Underground Assets
Substation and towers and conductors Underground conductor under
Land buildings fixtures and devices conduit and devices Services construction
TotalCost:
Balance, December 31, 2019 $ 258,350 $ 462,673 $ 3,945,562 $ 5,139,842 $
1,236,713 $ 2,683,591 $ 3,907,690 $ 1,363,879 $ 18,998,300
Additions during the year - 50,192 2,025,406 226,900 49,766 265,109 206,769
101,662 2,925,804
Transfers during the year - - - - - - - (1,583,020) (1,583,020)
Disposals during the year - - - (4,670) (8,025) - (27,382) - (40,077)
Balance, December 31, 2020 258,350 512,865 5,970,968 5,362,072 1,278,454
2,948,700 4,087,077 (117,479) 20,301,007Accumulated depreciation
Balance, December 31, 2019 - 106,924 1,215,097 1,038,519 410,532 523,553
2,061,658 - 5,356,283
Depreciation for the year - 27,956 204,155 185,346 40,185 102,828 356,029 -

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Notes to the financial statements

916,499Disposals during the year - - - (4,670) (8,025) - (27,382) - (40,077)
Balance, December 31, 2020 - 134,880 1,419,252 1,219,195 442,692 626,381
2,390,305 - 6,232,705Net book value
Balance, December 31, 2019 $ 258,350 $ 355,749 $ 2,730,465 $ 4,101,323 $
826,181 $ 2,160,038 $ 1,846,032 $ 1,363,879 $ 13,642,017
Balance, December 31, 2020 258,350 377,985 4,551,716 4,142,877 835,762
2,322,319 1,696,772 (117,479) 14,068,302
During the year, no provision for the cost of funds used during construction
was capitalized. Included in additions is a right of use asset of $45,570
which is non-cash and is not included in the statement of cash flows.
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
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7. Property, plant and equipment (continued):
Poles, Overhead Underground Assets
Substation and towers and conductors Underground conductor under
Land buildings fixtures and devices conduit and devices Services construction
TotalCost:
Balance, December 31, 2018 $ 258,350 $ 458,483 $ 3,857,171 $ 4,772,325 $
1,081,904 $ 2,390,071 $ 3,677,721 $ - $ 16,496,025
Additions during the year - 4,190 147,245 367,517 154,809 444,627 507,664
1,363,879 2,989,931
Disposals during the year - - (58,854) - - (151,107) (277,695) - (487,656)
Balance, December 31, 2019 258,350 462,673 3,945,562 5,139,842 1,236,713
2,683,591 3,907,690 1,363,879 18,998,300Accumulated depreciation
Balance, December 31, 2018 - 87,696 1,021,043 857,721 351,519 382,685
2,004,079 - 4,704,743
Depreciation for the year - 19,228 194,054 180,798 59,013 140,868 335,274 -
929,235Disposals during the year - - - - - - (277,695) - (277,695)
Balance, December 31, 2019 - 106,924 1,215,097 1,038,519 410,532 523,553
2,061,658 - 5,356,283Net book value
Balance, December 31, 2018 $ 258,350 $ 370,787 $ 2,836,128 $ 3,914,604 $
730,385 $ 2,007,386 $ 1,673,642 $ - $ 11,791,282
Balance, December 31, 2019 258,350 355,749 2,730,465 4,101,323 826,181
2,160,038 1,846,032 1,363,879 13,642,01723
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
8. Intangible assets:
Intangible assets consist of the following:
Land Computer
rights software Total
Cost:
Balance, December 31, 2019 $ 2,748 $ 286,017 $ 288,765
Additions - 5,473 5,473
Disposals - (103,007) (103,007)
Balance, December 31, 2020 2,748 188,483 191,231
Accumulated amortization
Balance, December 31, 2019 2,010 260,750 262,760
Amortization for the year 335 15,937 16,272
Disposals - (103,007) (103,007)
Balance, December 31, 2020 2,345 173,680 176,025
Carrying amount
Balance, December 31, 2019 $ 738 $ 25,267 $ 26,005
Balance, December 31, 2020 403 14,803 15,206

Corporation's name	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

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Notes to the financial statements

Land Computer
rights software Total
Cost:
Balance, December 31, 2018 $ 2,748 $ 269,356 $ 272,104
Additions - 16,661 16,661
Balance, December 31, 2019 2,748 286,017 288,765
Accumulated amortization
Balance, December 31, 2018 1,675 239,343 241,018
Amortization for the year 335 21,407 21,742
Balance, December 31, 2019 2,010 260,750 262,760
Carrying amount
Balance, December 31, 2018 $ 1,073 $ 30,013 $ 31,086
Balance, December 31, 2019 738 25,267 26,005
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
9. Payments in lieu of corporate income taxes:
PILs recognized in total income comprise the following:
2020 2019
Current tax expense:
Current year $ 28,438 $ 119,672
Deferred tax expense:
Origination and reversal of temporary differences 151,120 53,536
$ 179,558 $ 253,208
Statutory Canadian federal and provincial tax rates for the current year
comprise 15% (2019 -
15%) for federal corporate tax and 11.5% (2019 - 11.5%) for corporate tax in
Ontario. The PILs
expense varies from amounts which would be computed by applying the
Corporation's combinedstatutory income tax rate as follows:
2020 2019
Income before provision for PILs $ 706,090 $ 968,478
Statutory Canadian federal and provincial tax rate 26.50% 26.50%
Provision for PILs at statutory rate 187,114 256,647
Increase (decrease) in income tax resulting from:
Permanent differences 92 2,838
Regulatory (7,648) (6,277)
$ 179,558 $ 253,208
Effective tax rate 25.43% 26.10%
The movement in the deferred tax asset is as follows:
2020 2019
Opening balance, January 1 $ 845,115 $ 898,651
Recognized in regulatory deferral credits (151,120) (53,536)
Closing balance, December 31 $ 693,995 $ 845,115
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
9. Payments in lieu of corporate income taxes (continued):
Deferred tax assets are attributable to the following:
2020 2019
Property, plant and equipment $ 540,821 $ 708,938
Employee future benefits 153,174 136,177
$ 693,995 $ 845,115
The utilization of this tax asset is dependent on future taxable profits in

excess of profits arising
from the reversal of existing taxable temporary differences. The Corporation
believes that this
asset should be recognized as it will be recovered through future services.
10. Regulatory deferral accounts:
All amounts deferred as regulatory account debit balances are subject to
approval by the OEB.
As such, amounts subject to deferral could be altered by the regulators.
Due to previous, existing or expected future regulatory articles or
decisions, the Corporation has
the following amounts expected to be recovered from customer (returned to
customers) in future
periods and as such regulatory deferral account balances are comprised of:
Balances
Dec 31, arising in Recovery/ Other Dec 31,
2019 the period reversal movements* 2020
Regulatory assets:
RARA approved
May 1, 2019 $ 287,349 $ (220,111) $ - $ - $ 67,238
Regulatory liabilities:
Regulatory liability for
deferred income taxes 845,115 (151,120) - - 693,995
RARA approved
May 1, 2016 40,524 2,193 - - 42,717
Retail settlement variances 706,745 (673,143) - - 33,602
Pole Attachment variance 128,154 - 207,839 - 335,993
1,720,538 (822,070) 207,839 - 1,106,307
Net regulatory liability $ (1,433,189) $ 601,959 $ (207,839) $ 797,163 $
(1,039,069)*Other movements represent reclassifications of balances.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
10. Regulatory deferral accounts (continued):
Carrying charges
Carrying charges are calculated monthly on the opening balance of the
applicable variance
account using a specified interest rate as outlined by the OEB. The
Corporation intends to seek
recovery of carrying charge income earned in future rate applications.
Regulatory asset recovery accounts ("RARA")
The RARA are comprised of the cumulative balances of regulatory assets and
regulatory
liabilities approved for disposition by the OEB, reduced by amounts settled
with customers
through billing of approved disposition rate riders. The RARA are subject to
carrying chargesfollowing the OEB prescribed methodology and rates.
In 2016 the Corporation received approval in its Cost of Service Application
to dispose of the
RARA balances from December 31, 2010 and May 1, 2012. These liabilities were
transferred to
the RARA effective May 1, 2016. The RARA amounts from May 1, 2013 were
approved fordisposal by the OEB.
The RARA approved May 1, 2016 have expired and the Corporation will apply for
disposal of the
remaining balances in the next Cost of Service Application to the OEB.

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For rates effective May 1, 2019, the Corporation applied and was approved for
a RARA for rates
effective May 1, 2019 by the OEB. The RARA will be recovered from customers
(returned to
customers) through a variety of rate-riders implemented May 1, 2020 and
ending April 30, 2021.Retail settlement variances ("RSVAs")
RSVAs are comprised of the variances between amounts charged by the
Corporation to its
customers, based on regulated rates, and the corresponding cost of
non-competitive electricity
service incurred by the Corporation. The settlement variances relate
primarily to service charges,
non-competitive electricity charges and the global adjustment. Accordingly,
the Corporation has
deferred the variances between the costs incurred and the related recoveries
in accordance with
the criteria set out in the accounting principles prescribed by the OEB. The
balance for settlement
variances continues to be calculated and attracts carrying charges in
accordance with the OEB'sdirection.
Deferred income taxes
This regulatory liability account relates to the expected future electricity
distribution rate
adjustments for customers arising from timing differences in the recognition
of future incometaxes.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
10. Regulatory deferral accounts (continued):
Other
Included in other are amounts related to pole attachment variance and to
incremental capital
module. The OEB approved an increase in the pole attachment charges effective
January 1,
2019. The incremental capital module provides electricity distributors with a
funding mechanism
to address their capital needs. ORPC applied for incremental capital funding
of $1,698,850 to
build a new substation. The application was approved by the OEB in 2019. As
of December 31,
2020, ORPC incurred $2,059,754 (2019 - $1,363,879) in construction costs
related to the
substation and recovered $211,883 (2019 - $84,776) from customers.
11. Accounts payable and accrued liabilities:
2020 2019
Hydro One $ 2,062,489 $ 2,591,636
Embedded generation 562,505 478,729
Trade payables 459,212 624,200
Accrued interest on long-term debt 162 77,735
Customer credit balances 524,637 538,989
Other accounts payable and accruals 1,176,237 416,683
Customer deposits 25,053 95,865
Due to relates parties 98,632 80,982
$ 4,908,927 $ 4,904,819
Due to its short-term nature, the carrying amount of the accounts payable and

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Notes to the financial statements

accrued liabilitiesapproximates its fair value.
12. Contributions in aid of construction:
The continuity of deferred contributions in aid of construction is as follows:

	2020	2019
Deferred contributions, net, beginning of year	$ 1,033,626	$ 745,012
Contributions in aid of construction received	101,293	312,300
Contributions in aid of construction recognized as other revenue	(28,856)	(23,686)
Deferred contributions, net, end of year	$ 1,106,063	$ 1,033,626

All contributions in aid of construction are cash contributions. There has not been anycontributions of property, plant and equipment.

13. Employee future benefits:
(a) Pension plan:
The employees of the Corporation participate in the Ontario Municipal Employees Retirement System ("OMERS"). Although the plan has a defined retirement benefit plan for employees, the related obligation of the Corporation cannot be identified. The OMERS plan has several unrelated participating municipalities and costs are not specifically attributed to eachparticipant.
The plan specifies the amount of the retirement benefit to be received by the employees based on the length of service and rates of pay. The plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund. The employer portion of amounts paid to OMERS during the year was $208,385 (2019 - $192,175). The contributions were made for current service $204,363 (2019 - $192,175) and past service $4,022 (2019 - $Nil) and these have been recognized in total income.
Each year, an independent actuary determines the funding status of OMERS PrimaryPension Plan by comparing the actuarial value of invested assets to the estimated present value of all pension benefits that members have earned to date. The most recent actuarial valuation of the Plan was conducted at December 31, 2020. The results of this valuation disclosed total actuarial liabilities of $111.8 billion (2019 - $106.4 billion) in respect of benefits accrued for service with actuarial assets at that date of $108.6 billion (2019 - $103.0 billion), indicating an actuarial deficit of $3.2 billion (2019 - $3.4 billion). Because OMERS is a multiemployer plan, any pension plan surpluses or deficits are a joint responsibility of Ontario municipal organizations and their employees, as a result, the Corporation does not recognizeany share of the OMERS pension surplus or deficit.
(b) Post-employment life insurance plan:
The Corporation provides unfunded life insurance benefits on behalf of its

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retired employees.
These benefits are provided through a group defined benefit plan. The Corporation has
reported its share of the defined benefit costs and related liabilities, as calculated by an
actuary, in these financial statements. The accrued benefit liability and the expense for the
year ended December 31, 2020 is based on results determined by actuarial valuation as atDecember 31, 2019.
The plan is exposed to a number of risks, including:
? Interest rate risk: decreases/increases in the discount rate used (high quality corporatebonds) will increase/decrease the defined benefit obligation.
? Longevity risk: changes in the estimation of mortality rates of current and formeremployees.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
13. Employee future benefits (continued):
(b) Post-employment life insurance plan (continued):
Information about the group unfunded defined benefit plan as a whole and changes in the
present value of the unfunded defined benefit obligation and the accrued benefit liability areas follows:
2020 2019
Defined benefit obligation, beginning of year $ 377,700 $ 192,672
Amounts recognized in net income:
Current service cost 4,497 4,712
Interest on cost obligation 11,994 5,741
16,941 10,453
Benefit payments (26,291) (24,211)
Projected defined benefit obligation before
actuarial valuation 367,900 178,914
Actuarial loss recognized in other comprehensive income 56,942 198,786
Defined benefit obligation, end of year $ 424,842 $ 377,700
Significant actuarial assumptions for the measurement of the defined benefit obligation as atDecember 31 are as follows:
2020 2019
Discount rate 2.50% 3.25%
Rate of compensation increase 2.65% 2.65%
Retirement age Variable Variable
Sensitivity analysis for each significant actuarial assumption to which the Corporation isexposed is as follows:
? 1% decrease in the discount rate increases the defined benefit obligation by $88,400.
? 1% increase in the discount rate decreases the defined benefit obligation by $66,500.
? Change with 1-year greater life expectancy decrease the defined benefit obligationby $14,200.
? Change with 1-year increase in retirement age assumption decrease the defined benefitobligation by $1,000.
? The expected average remaining service lifetime at December 31, 2020 was 18.2 years(2019 - 18.2 years).
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)

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Notes to the financial statements

Year ended December 31, 2020
14. Long-term debt:
2020 2019
5.37182% Promissory note payable to the Corporation
of the City of Pembroke, due May 1, 2022 $ 4,364,000 $ 4,364,000
5.37182% Promissory note payable to the Corporation
of the Village of Beachburg, due May 1, 2022 147,000 147,000
5.37182% Promissory note payable to the Corporation
of the Township of Killaloe, Hagarty and Richards,
due May 1, 2022 172,348 172,348
5.37182% Promissory note payable to the Corporation
of the Town of Mississippi Mills, due May 1, 2022 902,490 902,490
2.56% Promissory note payable in blended monthly
payments of $ 7,112 to Ontario Infrastructure and
Lands Corporation, due June 30, 2050 1,765,930 -
7,351,768 5,585,838
Less: current portion of long-term debt 41,664 -
$ 7,310,104 $ 5,585,838
In January 2019 the Corporation obtained a construction loan from Ontario
Infrastructure and
Lands Corporation in order to fund the construction of a new substation in
Almonte. The
agreement provided two credit facilities for a total committed amount of
$1,785,850. The facilities
are a short term loan which is a non-revolving floating rate construction
loan and a term loan
which is a non-revolving fixed rate term loan. In fiscal 2019 the Corporation
received proceeds of
$1,219,507 against the non-revolving construction loan. The shot term
facility matured at the
earlier of project completion or June 2020. Upon completion of the project
the short term loan
was converted to the term loan with a maturity date of June 30, 2050.
Interest on promissory notes is calculated annually and payable quarterly to
the shareholders.31
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
15. Capital stock:
(a) Authorized:
Unlimited number of common shares
Unlimited number of non-cumulative special shares
Unlimited number of non-voting, non-cumulative Class A special shares,
redeemable at onedollar per share
Unlimited number of non-voting, non-cumulative Class B special shares,
redeemable at onedollar per share
Unlimited number of non-voting, non-cumulative Class C special shares,
redeemable at onedollar per share
Unlimited number of non-voting, non-cumulative Class D special shares,
redeemable at onedollar per share
Articles of amendment were issued on October 17, 2014 to authorize the Class
A, B, C and D
special shares. Class A, B, C and D special shares were issued on January 15,
2015.Dividends on special shares are payable at the discretion of the Board
of
Directors.(b) Issued:

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As at December 31, 2020, the common shares of the Corporation are held as follows:Common Percentage
shares ownership
Corporation of the City of Pembroke 4,364 78.38%
Corporation of the Town of Mississippi Mills 888 15.94%
Corporation of the Township of Killaloe, Hagarty and Richards 169 3.04%
Corporation of the Township of Whitewater Region 147 2.64%
5,568 100.00%
No movement in common share capital has occurred during 2020 or 2019.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
15. Capital stock (continued):
(b) Authorized (continued):
As at December 31, 2020, the special shares of the Corporation are held as follows:Special
shares Class
Corporation of the City of Pembroke 4,364 A
Corporation of the Town of Mississippi Mills 888 B
Corporation of the Township of Killaloe, Hagarty and Richards 169 C
Corporation of the Township of Whitewater Region 147 D
5,568
The special shares were issued on January 15, 2015. There was no movement on specialshare capital during 2020 or 2019.
(c) Dividends per share:
2020 2019
Class A special shares $ - $ 44.25
Class B special shares - 73.41
Class C special shares - 73.29
Class D special shares - 52.88
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
16. Commitments:
City of Pembroke
The Corporation rents its premises in Pembroke, Ontario, from the Corporation of The City of
Pembroke under the terms of a ten-year operating lease at an annual rental of $12. The lease
contained an option which allowed the lessee to purchase the property on or before December 1,
2009, at a cost of three hundred and sixty thousand, five hundred and eighty-three dollars
($360,583) together with any assessable environmental clean-up costs. The Corporation is
currently in discussions with the Corporation of the City of Pembroke regarding the status of thislease.
Mississippi River Power Corporation
The Corporation rents office premises from Mississippi River Power Corporation at a monthly cost
of $10,438. The lease expires on September 30, 2025.
The Corporation rents substation premises from Mississippi River Power Corporation at amonthly cost of $575. The lease expires on December 31, 2026.
Runge Stationers

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Notes to the financial statements

The Corporation rents a postage machine premises from Runge Stationers at a monthly cost of$548. The lease expires on June 1, 2021.

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OTTAWA RIVER POWER CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2020

17. Contingencies:

(a) Insurance claims:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance
Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group ofpersons formed for the purpose of exchanging reciprocal contracts of indemnity or interinsurance
with each other. MEARIE is licensed to provide general liability insurance to member electric utilities.

Insurance premiums charged to each municipal electric utility consist of a levy per thousand
dollars of service revenue subject to a credit or surcharge based on each electric utility's
claims experience. Effective January 1, 2001, coverage is provided to a level of $20 millionper incident.

No provision has been made for these potential liabilities as the Corporation expects thatthese claims are adequately covered by its insurance.

18. Revenue:

2020 2019

Revenue from contracts with customers

Power recovery $ 26,611,504 $ 23,310,296

Distribution:

Residential service 3,024,238 3,086,650

General service 864,436 911,048

Larger users 935,864 954,104

4,824,538 4,951,802

$ 31,436,042 $ 28,262,098

2020 2019

Other operating revenue:

Late payment charges $ 29,688 $ 47,921

Property and equipment rent 83,947 44,436

Change of occupancy and connection fees 46,500 48,983

Merchandising jobbing 440,859 671,758

Interest 5,455 12,967

Billing and collection charges 7,301 10,785

Gain on disposal of property, plant and equipment - 43,872

$ 613,750 $ 880,722

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OTTAWA RIVER POWER CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2020

19. Expenses by nature:

Distribution operation and maintenance

2020 2019

Materials, supplies, small tools recovery $ (54,686) $ (33,658)

Salaries and benefits 1,018,835 986,773

Training and travel 10,908 59,900

Office and general 55,815 2,127

Utilities 45,718 41,317

Insurance 5 3,145

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Notes to the financial statements

Property taxes 23,172 12,307
$ 1,099,767 $ 1,071,911
Community relations
2020 2019
Advertising $ 35,251 $ 28,478
Safety program 1,412 35,779
$ 36,663 $ 64,257
Billing and collecting
2020 2019
Smart meter reading and operations $ 55,013 $ 52,758
Postage 112,995 116,709
Salaries and benefits 487,242 382,247
Information technology 60,738 60,576
Office and general 72,812 31,620
Bad debts 57,859 105,151
Collection agency costs (1,978) 9,948
$ 844,681 $ 759,009
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
19. Expenses by nature (continued):
General and administrative
2020 2019
Salaries and benefits $ 759,607 $ 715,736
Memberships, fees and dues 87,471 88,063
Legal 12,878 20,330
Audit 49,953 57,222
Professional Services 4,200 -
Building maintenance 96,494 134,332
Advertising 4,720 5,200
Regulatory 120,822 116,010
Information technology 19,145 19,225
Telephone 42,988 40,604
Insurance 35,105 29,852
Bank charges 21,615 25,051
Office supplies and materials 34,255 53,610
$ 1,289,253 $ 1,305,235
20. Financial risk management:
As part of its operations, the Corporation carries out transactions that expose it to financial risks
such as credit, liquidity and market risks. The following is a discussion of risks and related
mitigation strategies that have been identified by the Corporation for financial instruments. This is
not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks identified.(a) Credit risk:
Credit risk is the risk that one party to a financial instrument will cause a loss for the other
party by failing to pay for its obligation. The maximum credit exposure is limited to the
carrying amount of cash, accounts receivable, and unbilled revenue presented on thebalance sheet.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)

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Notes to the financial statements

Year ended December 31, 2020
20. Financial risk management (continued):
(a) Credit risk (continued):
The Corporation limits its exposure to credit loss by placing its cash with a high credit quality
financial institution. The Corporation maintains cash with two major financial institutions.
Eligible deposits per financial institution are insured to a maximum basic insurance level of
$100,000, including principal and interest by the Canada Deposit Insurance Corporation. The
Corporation is exposed to credit risk related to accounts receivable and unbilled revenue
arising from its day-to-day electricity and service revenue. Exposure to credit risk is limited
due to the Corporation's large and diverse customer base. The Corporation has
approximately 11,000 customers, the majority of which are residential. No single customer
accounts for revenue in excess of 10% of total revenue. The Corporation limits its credit risk
by collecting deposits, following collection policies, monitoring accounts receivable aging, and
utilizing collection agencies. The Ontario Energy Board has prescribed certain rules for the
payment of deposits by customers. Although these rules limit the risk of the Corporation, no
deposits are required by customers who have shown good payment history for the previous
12-month period. The Corporation does not have any material accounts receivable balances
greater than 90 days outstanding. The Corporation believes that its accounts receivablerepresent a low credit risk.
The carrying amount of accounts receivable is reduced through the use of an allowance for
doubtful accounts and the amount of the related impairment loss is recognized in net income.
The provision is based on account age and customer standing. Subsequent
recoveries ofreceivables previously provisioned are credited to net income.
The value of accounts receivable, by age, and the related bad debt provision are presented in
the following table. Unbilled revenue which is not included in the table below is considered allcurrent.

	2020	2019
Under 30 days	$ 2,535,849	$ 2,963,895
30 to 60 days	90,554	75,169
61 to 90 days	66,513	58,595
Over 90 days	244,822	116,767
	2,937,738	3,214,426
Allowance for doubtful accounts	(179,775)	(99,382)
Total accounts receivable	$ 2,757,963	$ 3,115,044

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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
20. Financial risk management (continued):
(b) Liquidity risk:

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Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they come due. 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 $1,000,000 line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financialcommitments as they come due.

0 to 3 3 months 1 year to
months to 1 year 2 years Thereafter
Accounts payable and
accrued liabilities $ 4,908,927 $ - $ - $ -
Long-term debt 10,056 31,608 5,627,502 1,682,602
Total, December 31, 2020 $ 4,918,983 $ 31,608 $ 5,627,502 $ 1,682,602
0 to 3 3 months 1 year to
months to 1 year 2 years Thereafter
Accounts payable and
accrued liabilities $ 4,904,819 $ - $ - $ -
Loan payable 1,222,312 - - -
Line of credit 400,000
Long-term debt 74,930 175,035 300,060 5,585,838
Total, December 31, 2019 $ 6,602,061 $ 175,035 $ 300,060 $ 5,585,838

(c) Market risk:

The Corporation is not exposed to significant market risk given they do not have investments in foreign currency, and have minimal investment in interest bearing instruments.(d) Impact of COVID-19:

In March 2020, the COVID-19 outbreak was declared a pandemic by the World HealthOrganization. This resulted in governments worldwide, enacting emergency measures to combat the spread of the virus. Beyond COVID-19 restrictions at operating locations the COVID-19 pandemic has not had a significant impact on the Corporation to date. The situation is dynamic and continuously evolving, and ultimately financial impact of the pandemic on the Corporation remains unknown as of the date of the approval of thesefinancial statements.

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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020

20. Financial risk management (continued):

(e) Changes in risk exposure:

Other than described in note 20(d), there has been no change to the Corporation's riskexposure from 2019

21. Energy purchase:

The Corporation is dependent on Hydro One for a significant portion of the electricity it purchases. The amount owing to Hydro One at December 31, 2020 is $2,062,489 (2019 -$2,591,635). Included in cost of power in the statement of income and

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comprehensive income is
$25,908,846 (2019 - $22,039,605) purchased from Hydro One.
22. Bank indebtedness, bankers' acceptances and letters of credit:
The Corporation has a bilateral demand line of credit for $1,000,000 with a
Canadian chartered
bank. The line of credit bears interest at the bank's prime rate. At December
31, 2020, noamounts had been drawn on the line of credit (2019 - $400,000).
23. Capital management:
The Corporation considers its capital to be its long-term debt, capital stock
and retained earnings.
The Corporation's main objectives when managing capital are to: i) ensure
sufficient liquidity to
maintain and improve its electricity distribution system, support its
financial obligations and
execute its operating and strategic plans; ii) minimize the cost of capital
while taking into
consideration current and future industry, market and economic risks and
conditions; iii) maintain
an optimal capital structure that provides necessary financial flexibility
and considers recoveries
of financing charges permitted by the OEB, while also ensuring compliance
with any financial
covenants, and iv) provide an adequate return to its shareholders.
The Corporation relies on its cash flow from operations to fund its dividend
distributions to itsshareholders.

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
Ottawa River Power Corporation	87176 4072 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			526,532	A
Add:				
Provision for income taxes – current	101	28,438		
Provision for income taxes – deferred	102	151,120		
Amortization of tangible assets	104	903,915		
Non-deductible meals and entertainment expenses	121	347		
Other reserves on lines 270 and 275 from Schedule 13	125	99,382		
Reserves from financial statements – balance at the end of the year	126	604,617		
Subtotal of additions		1,787,819	1,787,819	

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	CIAC increase	101,293
	Total of column 2	101,293

Total of column 2	296	101,293		
Subtotal of other additions	199	101,293	101,293	D
Total additions	500	1,889,112	1,889,112	
Amount A **plus** line 500			2,415,644	B
Deduct:				
Capital cost allowance from Schedule 8	403	1,370,200		
Other reserves on line 280 from Schedule 13	413	179,775		
Reserves from financial statements – balance at the beginning of the year	414	477,082		
Subtotal of deductions		2,027,057	2,027,057	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Amortization of contributions in aid of construction	28,856
2	FT in regulatory liabilities	151,120
3	Election - 13(7.4)	101,293
	Total of column 2	281,269

Total of column 2	396	281,269		
Subtotal of other deductions	499	281,269	281,269	E
Total deductions	510	2,308,326	2,308,326	
Net income (loss) for income tax purposes (amount B **minus** line 510)			107,318	C

Enter amount C on line 300 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
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- 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
107,318		107,318	12,342

	Line	Amount		Total	
Ontario basic income tax (from Schedule 500)	270	12,342			
Ontario small business deduction (from Schedule 500)	402				
Subtotal (line 270 **minus** line 402)		12,342	►	12,342	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)				12,342	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")				12,342	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")				12,342	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")				12,342	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)				12,342	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	12,342	

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 12,342

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
Ottawa River Power Corporation	87176 4072 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	Buildings	367,439	50,192	50,192				0	417,631
2.	2	Electrical distributing equipement	3,072,300						0	3,072,300
3.	8	Equipment	361,121	84,526	84,526				0	445,647
4.	10	Computer Hardware & Vehicles	258,872						0	258,872
5.	45	Computer Hardware	6,695	32,757	32,757				0	39,452
6.	47	Electrical distributing equipment	7,091,364	2,555,375	2,555,375				0	9,646,739
7.	50	Computer hardware post March 2007	3,073						0	3,073
8.	14.1		1,238,118						0	1,238,118
9.	12	Software		5,473					0	5,473
		Totals	12,398,982	2,728,323	2,722,850					15,127,305

	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	Buildings		50,192	25,096		4	0	0	17,709	399,922
2.	2	Electrical distributing equipem					6	0	0	184,338	2,887,962

	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
3.	8	Equipment		84,526	42,263		20	0	0	97,582	348,065
4.	10	Computer Hardware & Vehicle					30	0	0	77,662	181,210
5.	45	Computer Hardware		32,757	16,379		45	0	0	25,124	14,328
6.	47	Electrical distributing equipme		2,555,375	1,277,688		8	0	0	873,954	8,772,785
7.	50	Computer hardware post Marc					55	0	0	1,690	1,383
8.	14.1						5	0	0	86,668	1,151,450
9.	12	Software					100	0	0	5,473	
		Totals		2,722,850	1,361,426					1,370,200	13,757,105

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
Ottawa River Power Corporation	87176 4072 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	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	Ottawa River Energy Solutions Inc.		86613 9025 RC0001	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)

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SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on an amalgamation or the wind-up of a subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

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 $
Reserve for doubtful debts	X	110 99,382	115	179,775	99,382	120 179,775
Reserve for undelivered goods and services not rendered		130	135			140
Reserve for prepaid rent		150	155			160
Reserve for refundable containers		190	195			200
Reserve for unpaid amounts		210	215			220
Other tax reserves		230	235			240
Totals		270 99,382	275	179,775	99,382	280 179,775

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

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	Future Employee Benefits	377,700		424,842	377,700	424,842
2						
	Reserves from Part 2 of Schedule 13	99,382		179,775	99,382	179,775
	Totals	477,082		604,617	477,082	604,617

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.

Attached Schedule with Total

Part 1 – Financial statement reserves – Federal – Add

Title Part 1 – Financial statement reserves – Federal – Add

Description	Operator (Note)	Amount
Post Retirement Benefits - AP		
230600 OPEB Liability	+	424,842 00
	+	
	Total	424,842 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 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 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	47,142	1245045-01			

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 . . . . 47,142 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 47,142 B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer (EPSP only)

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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	Ottawa River Power Corporation	87176 4072 RC0001	1	500,000	100.0000	500,000	
2	Ottawa River Energy Solutions Inc.	86613 9025 RC0001	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
Ottawa River Power Corporation	87176 4072 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:

	Line	Amount		
Reserves that have not been deducted in calculating income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	5,591,406		
Retained earnings	104	3,923,266		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	7,351,768		
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)		16,866,440 ►	16,866,440	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)			16,866,440	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121	693,995		
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)		693,995 ►	693,995	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		16,172,445	

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	
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	

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)		16,172,445	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	16,172,445	

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) 16,172,445 x (Taxable income earned in Canada **610** 107,318 / Taxable income 107,318) = **Taxable capital employed in Canada** **690** 16,172,445

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
Due to ORES		
LT debt	+	7,310,104 00
Current portion of long term debt	+	41,664 00
	+	
	Total	7,351,768 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
Ottawa River Power Corporation	87176 4072 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	Corporation of the City of Pembroke	121936140RC0001			79.000	79.000
2	Corporation of the Town of Mississippi Mills	866266653RC0001			16.000	16.000
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Ottawa River Power Corporation	87176 4072 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	107,318	1A
Ontario basic rate of tax for the year	**11.5** %	1B
Ontario basic income tax (amount 1A **multiplied** by amount 1B) Note 2	12,342	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	107,318	2A
Line 405 of the T2 return	107,318	2B
Line 410 of the T2 return	500,000	2C
Line 415 of the T2 return	14,798	2D

Amount 2C 500,000 x Amount 2D 14,798 / 11,250 = 657,689 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 = 107,318.00 / 107,318 = 1.00000 2I

Amount 2H **multiplied** by amount 2I		2J
Ontario taxable income (amount 1A)	107,318	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
Ottawa River Power Corporation	87176 4072 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	24,400,539
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	2,308,691
Total assets (total of lines 112 to 116)		26,709,230
Total revenue of the corporation for the tax year **	142	32,443,913
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	1,109,729
Total revenue (total of lines 142 to 146)		33,553,642

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

Net income/loss per financial statements *			210	526,532
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	28,438		
Provision for deferred income taxes (debits)/cost of future income taxes	222	151,120		
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		179,558		179,558 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			
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	382			
383	384			
385	386			
387	388			
389	390			
Subtotal				B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	706,090

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** ______

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** ______

Amount from line 520 ______ 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 ______ x (Number of days in the tax year after June 30, 2010 366 / Number of days in the tax year 366) x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) . . . . ______ 3

Gross CMT: amount on line 3 above x OAF ** . . . . **540** ______

Deduct:

Foreign tax credit for CMT purposes *** . . . . **550** ______

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . ______ D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 12,342

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)		12,342 1		
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)	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:		6		
Subtotal (if negative, enter "0")		12,342 ►	12,342	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		12,342		
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")		12,342 ►	12,342	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 ☒

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.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Ottawa River Power Corporation	87176 4072 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	Ottawa River Energy Solutions Inc.	86613 9025 RC0001	2,308,691	1,109,729
		Total	450 2,308,691	550 1,109,729

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

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2021-12-31

Business number 87176 4072 RC0001

The following is a list of instalments payable for the current taxation year, and the last column indicates the instalments payable to the Canada Revenue Agency (CRA). The instalments must be paid on each of the dates indicated below, otherwise non-deductible interest might be charged.

Instalment payments can be made using one of the following methods:

- electronically, using your online or telephone banking services;
- online, using the CRA's *My Payment* service, at **canada.ca/cra-my-payment**;
- by setting up a pre-authorized debit agreement, in *My Business Account*, at **canada.ca/my-cra-business-account**;
- in person, at a Canadian financial institution, **by presenting the appropriate remittance voucher** with your payment.

You can also mail a cheque or a money order payable to the Receiver General of Canada, **accompanied by the appropriate remittance voucher**, to Canada Revenue Agency, P.O. Box 3800, Station A, Sudbury ON P3A 0C3.

Do you want to calculate the tax instalments according to the extended payment date (COVID-19)?* ☐ Yes ☒ No

* The answer to this question is **Yes** when at least one of the dates entered in the **Monthly instalment workchart** or the **Quarterly instalment workchart** sections is after March 17, 2020, and before September 30, 2020.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2021-01-31			16,640	-16,640	
2021-02-28			16,640	-33,280	
2021-03-31			16,640	-49,920	
2021-04-30			16,640	-66,560	
2021-05-31			16,000	-82,560	
2021-06-30				-82,560	
2021-07-31				-82,560	
2021-08-31				-82,560	
2021-09-30				-82,560	
2021-10-31				-82,560	
2021-11-30				-82,560	
2021-12-31				-82,560	
Instalment (COVID-19)					
Totals			82,560		-82,560

Canada Revenue Agency — Agence du revenu du Canada

Information Return for Corporations Filing Electronically

- **Do not send this form to the Canada Revenue Agency (CRA) unless we ask for it. We will not keep or return this form.**
- Complete this return for every initial and amended T2 Corporation Income Tax Return electronically filed with the CRA on your behalf.
- By completing Part 2 and signing Part 3, you acknowledge that, under the Income Tax Act, you have to keep all records used to prepare your T2 Corporation Income Tax Return, and provide this information to us on request.
- Part 4 must be completed by either you or the electronic transmitter of your T2 Corporation Income Tax Return.
- Give the signed original of this return to the transmitter and keep a copy in your own records for six years.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted your return.

Part 1 – Identification

Corporation's name: Ottawa River Power Corporation

Business number: 87176 4072 RC0001

Tax year start (Year Month Day): 2020-01-01

Tax year-end (Year Month Day): 2020-12-31

Is this an amended return? ☐ Yes ☒ No

Get your CRA mail electronically delivered in My Business Account at canada.ca/my-cra-business-account (optional)

Email address: ____________________

I understand that by providing an email address, I am **registering** the corporation to receive email notifications from the CRA. I understand and agree that all notices and other correspondence eligible for electronic delivery will no longer be printed and mailed. The CRA will notify the corporation at this email address when they are available in My Business Account and requiring immediate attention. They will be presumed to have been received on the date that the email is sent. For more information, see **canada.ca/cra-business-email-notifications**.

Part 2 – Declaration

Enter the following amounts, if applicable, from the T2 return for the tax year noted above:

Net income or loss for income tax purposes from Schedule 1, financial statements, or General Index of Financial Information (GIFI) (line 300)	107,318
Part I tax payable (line 700)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	

Part 3 – Certification and authorization

I, Roy (Last name) Jeffrey (First name), Chief Financial Officer (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the T2 Corporation Income Tax Return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information 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.

I authorize the transmitter identified in Part 4 to electronically file the T2 Corporation Income Tax Return identified in Part 1. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

Date (yyyy/mm/dd): ____________ Signature of an authorized signing officer of the corporation: ____________ Telephone number: (613) 732-3687

Part 4 – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part 1.

Name of person or firm: KPMG LLP

Electronic filer number: A8340

Privacy statement

Personal information 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 and CRA PPU 211 on Info Source at **canada.ca/cra-info-source**.

200

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

EXEMPT FROM TAX

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 87176 4072 RC0001

Corporation's name
002 Ottawa River Power Corporation

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.
011 283 Pembroke Street W
012
City: 015 Pembroke
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal or ZIP code: 018 K8A 5N5

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
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal or ZIP code: 028

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)
[X] 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		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		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		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	X	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		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		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	Energy	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		107,318	A
Deduct:				
Charitable donations from Schedule 2	311			
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		►		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			107,318	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		107,318	
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	107,318	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		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 *** 14,798 D / 11,250 = 657,689 E

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** 417 ______ – 50,000 = ______ F

Amount C 500,000 / 100,000 x Amount F ______ = ______ G

The greater of amount E and amount G	422	657,689	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				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")				H
General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 %				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		107,318	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)		107,318	K x 30 2 / 3 % =	32,911 L
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9)				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)	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")	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	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	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)	►		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) ______ I

Deduct:

Small business deduction from line 430 on page 4			J
Federal tax abatement	608		
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		
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		►	K

Part I tax payable – Amount I **minus** amount K ______ 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	
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		

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	
Total tax payable	770	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	
Total credits	890	B

Balance (amount A **minus** amount B)

Refund code 894 1 Refund

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 A8340

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Roy (Last name) 951 Jeffrey (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 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 (613) 732-3687 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

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	9,304,857	9,340,912
	Total tangible capital assets	2008	+	20,301,005	18,998,299
	Total accumulated amortization of tangible capital assets	2009	–	6,232,705	5,356,283
	Total intangible capital assets	2178	+	191,230	288,764
	Total accumulated amortization of intangible capital assets	2179	–	176,024	262,759
	Total long-term assets	2589	+	1,012,176	1,221,236
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	24,400,539	24,230,169
Liabilities					
	Total current liabilities	3139	+	4,956,507	6,524,326
	Total long-term liabilities	3450	+	9,986,302	8,717,703
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	14,942,809	15,242,029
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	9,457,730	8,988,140
	Total liabilities and shareholder equity	3640	=	24,400,539	24,230,169
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	3,923,266	3,595,520

* Generic item

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year-end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	31,436,043	28,262,098
	Cost of sales	8518	–	26,867,428	21,833,638
	Gross profit/loss	8519	=	4,568,615	6,428,460
	Cost of sales	8518	+	26,867,428	21,833,638
	Total operating expenses	9367	+	4,870,395	6,340,704
	Total expenses (mandatory field)	9368	=	31,737,823	28,174,342
	Total revenue (mandatory field)	8299	+	32,443,913	29,142,819
	Total expenses (mandatory field)	9368	–	31,737,823	28,174,342
	Net non-farming income	9369	=	706,090	968,477
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	706,090	968,477
	Total – other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	28,438	199,672
	Future (deferred) income tax provision	9995	–	151,120	53,536
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	526,532	715,269

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax Year End Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, General Index of Financial Information (GIFI) and T4012, T2 Corporation – Income Tax Guide.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . 095 Yes [X] No [ ]

Is the accountant connected* with the corporation? . . . . . 097 Yes [ ] No [X]

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: 198

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . 099 Yes [ ] No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: 110

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . 101 Yes [X] No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . 104 Yes [ ] No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . 105 Yes [ ] No [X]

Is contingent liability information mentioned in the notes? . . . . . 106 Yes [X] No [ ]

Is information regarding commitments mentioned in the notes? . . . . . 107 Yes [X] No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . 108 Yes [ ] No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** Yes [ ] No [X]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** Yes [ ] No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** Yes [ ] No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** Yes [ ] No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** Yes [ ] No [X]

If **yes**, you have to maintain a separate reconciliation.

Corporation's name	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

General Index of Financial Information

Notes to the financial statements

Ottawa River Power Corporation (the "Corporation") was incorporated in accordance with the
provincial government's Electricity Act, 1998 under the Business Corporations Act (Ontario) on
April 22, 1999. Ottawa River Power Corporation is the successor to the former Pembroke Hydro
Electric Commission ("Pembroke Hydro"), the Town of Mississippi Mills Public Utilities
Commission ("Almonte Hydro"), the Township of Killaloe, Hagarty & Richards Hydro Electric
Commission ("Killaloe Hydro") and the Beachburg Hydro System ("Beachburg Hydro").
The shareholders of the Corporation are the City of Pembroke (78.4%), the Town of Mississippi
Mills (15.9%), the Township of Killaloe-Hagarty-Richards (3.0%) and the Township of WhitewaterRegion (2.7%).
The Corporation is the electric distribution utility for residents of the City of Pembroke, the Town
of Mississippi Mills (Almonte Ward), the Township of Killaloe and the Village of Beachburg under
a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB
and adjustments to the Corporation's distribution and power rates require OEB approval.1. Basis of presentation:
(a) Statement of compliance:
These financial statements have been prepared by management on a going-concern basis in
accordance with International Financial Reporting Standards ("IFRS") as issued by the
International Accounting Standards Board ("IASB") and interpretations as issued by the
International Financial Reporting Interpretations Committee ("IFRIC") of the IASB.
The financial statements were authorized for issue by the Board of Directors on April 22,2021.
(b) Basis of presentation:
The financial statements have been prepared on the historical cost basis.
(c) Functional and presentation currency:
These financial statements are presented in Canadian dollars, which is the Corporation's
functional currency. All financial information presented has been rounded to the nearestdollar.
(d) Use of estimates and judgments:
The preparation of financial statements in compliance with IFRS requires management to
make certain critical accounting estimates. It also requires management to exercise judgment
in applying the Corporation's accounting policies. The areas involving a higher degree of
judgment, complexity, or areas where assumptions and estimates are
significant to thefinancial statements are disclosed in note 3.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
1. Basis of presentation (continued):

General Index of Financial Information

Notes to the financial statements

(e) Explanation of activities subject to rate regulation:
Ottawa River Power Corporation, as an electricity distributor, is both licensed and regulated
by the OEB which has a legislative mandate to oversee various aspects of the electricity
industry. The OEB exercises statutory authority through setting or approving all rates charged
by the Corporation and establishing standards of service for the Corporation's customers.
The OEB has broad powers relating to licensing, standards of conduct and service and the
regulation of rates charged by the Corporation and other electricity distributors in Ontario.
The Ontario government enacted the Energy Competition Act, 1998, to introduce competition
to the Ontario energy market. Rates are set by the OEB on an annual basis for May 1 toApril 30.
Regulatory risk
Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a
regulatory regime that imposes conditions that restrict the electricity distribution business
from achieving an acceptable rate of return that permits financial sustainability of its
operations including the recovery of expenses incurred for the benefit of other market
participants in the electricity industry such as transition costs and other regulatory assets. All
requests for changes in electricity distribution charges require the approval of the OEB.Recovery risk
Regulatory developments in Ontario's electricity industry, including current and possible
future consultations between the OEB and interested stakeholders, may affect distribution
rates and other permitted recoveries in the future. The Corporation is subject to a cost of
service regulatory mechanism under which the OEB establishes the revenues required (i) to
recover the forecast operating costs, including depreciation and amortization and income
taxes, of providing regulated service, and (ii) to provide a fair and reasonable return on utility
investment, or rate base. As actual operating conditions may vary from
forecast, actualreturns achieved can differ from approved returns.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies:
The preparation and presentation of financial statements can be significantly affected by the
accounting policies selected by the Corporation. The financial statements reflect the following
significant accounting policies, which are an integral part of understanding them.
The accounting policies set out below have been applied consistently to all

General Index of Financial Information

Notes to the financial statements

periods presented inthese financial statements unless otherwise indicated.
(a) Regulatory deferral accounts:
Regulatory deferral account debit balances represent future revenues associated with certain
costs incurred in the current period or in prior period(s) that are expected to be recovered
from consumers in future periods through the rate-setting process. Regulatory deferral
account credit balances are associated with the collection of certain revenue earned in the
current period or prior period(s) that are expected to be returned to consumers in future
periods through the rate-setting process. Regulatory deferral account balances can arise
from differences in amounts collected from customers (based on regulated rates) and the
corresponding cost of non-competitive electricity service incurred by the Corporation in the
wholesale market administered by the Independent Electricity System Operator (the "IESO")
after May 1, 2002. These amounts have been accumulated pursuant to regulation underlying
the Electricity Act (the "EA") and deferred in anticipation of their future
recovery or expense inelectricity distribution service charges.
Explanation of recognized amounts
Regulatory deferral account balances are recognized and measured initially and
subsequently at cost. They are assessed for impairment on the same basis as
othernonfinancial assets as described below.
Management continually assesses the likelihood of recovery of regulatory deferral accounts.
If recovery through future rates is no longer considered probable, the amounts would be
charged to the results of operations in the period that the assessment is made.(b) Revenue recognition:
The Corporation recognizes revenue from contracts with customers when it transfers control
over a product or service to a customer either over time or at a point in time. Revenue is
measured at the consideration received or receivable, excluding sales taxes and other
amounts collected on behalf of third parties. Revenue is comprised of sales and distribution
of energy, pole use rental, collection charges, administrative services and
othermiscellaneous revenue.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(b) Revenue recognition (continued):
Sale and distribution of energy
The Corporation is licensed by the OEB to distribute electricity. 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

General Index of Financial Information

Notes to the financial statements

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 has determined that
they are acting
as a principal for the electricity distribution and, therefore, have
presented the electricityrevenues on a gross basis.
Revenues from the sale and distribution of electricity is recognized over
time as electricity isdelivered to the customer, as measured by meter
readings.
Other Revenues
Other revenues, which include revenues from pole use rental, collection
charges,
administrative services and other miscellaneous revenues are recognized over
time as the
services are provided, except for revenue from certain account-related
charges, which isrecognized at a point in time.
Where the Corporation has an ongoing obligation to provide services, revenues
arerecognized over time as the services are performed. Revenue earned for
service workrelated to distribution operations is recognized over time as the
corresponding costs are
recognized proportionately with the degree of completion of the services
under contract.Amounts billed in advance are recognized as deferred revenue.
Contributions in aid of construction
Certain assets may be acquired or constructed with financial assistance in
the form of
contributions from developers when the estimated revenue is less than the
cost of providing
service or where special equipment is needed to supply specific requirements.
Capitalcontributions from developers are recognized as deferred revenue and
amortized into
revenue from other sources at an equivalent rate to that used for the
depreciation of therelated property, plant and equipment.
(c) Cash:
Cash includes cash on hand with financial institutions.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(d) Financial instruments:
Financial assets and financial liabilities are recognized when the
Corporation becomes aparty to the contractual provisions of the instrument.
Accounts receivable and unbilled energy revenue are initially measured at the
transaction
price. All other financial assets and financial liabilities are initially
measured at fair value.
The Corporation determines the classification of its financial assets on the
basis of both the
business model for managing the financial assets and the contractual cash flow
characteristics of the financial asset. Financial assets are not reclassified
subsequent to their
initial recognition unless the Corporation changes its business model for
managing financialassets.

General Index of Financial Information

Notes to the financial statements

A financial asset is measured at amortized cost if it is held within a business model whose
objective is to hold assets to collect contractual cash flows, and its contractual terms give rise
on specified dates to cash flows that are solely payments of principal and interest on theprincipal amount outstanding.
Financial assets are classified as amortized cost. These include cash, accounts receivable,
unbilled energy revenue, and due from Ottawa River Energy Solutions. Subsequent to initial
recognition, financial assets at amortized cost are measured using the effective interestmethod, less any impairment.
The Corporation measures a loss allowance for expected credit losses ("ECLs") on financial
assets measured at amortized cost. The Corporation measures loss allowances for accounts
receivable and unbilled revenue via a simplified approach as permitted by IFRS 9, at an
amount equal to lifetime ECL. When determining whether the credit risk of a financial asset
has increase, the Corporation performs a quantitative and qualitative analysis based on the
Corporation's historical experience and forward-looking information.
Loss allowances for financial assets measured at amortized cost are deducted from the gross
carrying amount of the assets. The gross carrying amount of a financial asset is written off tothe extent there is no realistic prospect of recovery.
The Corporation determines the classification of its financial liabilities at initial recognition.
The Corporation's financial liabilities are classified as amortized cost. These include accounts
payable and accrued liabilities, due to Ottawa River Energy Solutions, customer deposits,loan payable, and long-term debt.
Financial liabilities at amortized cost are measured using the effective interest method.11
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(e) Customer deposits:
Customers may be required to post security to obtain electricity or other services, which are
refundable. Where the security posted is in the form of cash, these amounts are recorded in
the accounts as deposits. Deposits to be refunded to customers within the next fiscal year are
classified as a current liability. Interest rates paid on customer deposits are based on theBank of Canada's prime business rate less 2%.
(f) Property, plant and equipment:
Recognition and measurement
Property, plant and equipment ("PP&E") are recognized at cost less accumulated
depreciation and accumulated impairment losses. Cost includes the purchase price and
directly attributable cost of acquisition or construction required to bring the asset to the
location and condition necessary to be capable of operating in the manner

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intended by theCorporation, including eligible borrowing costs.
Depreciation of PP&E is recorded in the statement of comprehensive income on a straightline
basis over the estimated useful life of the related asset. The estimated useful lives,
residual values and amortization methods are reviewed at the end of each annual reporting
period, with the effect of any changes in estimate being accounted for on a prospective basis.The estimated useful lives are as follows:
Asset Useful life
Substation and buildings 30 to 60 years
Poles, towers and fixtures 25 to 45 years
Overhead conductors and devices 25 to 60 years
Underground conduit 25 to 50 years
Underground conductors and devices 25 to 40 years
Services 3 to 25 years
Major spare parts such as spare transformers and other items kept as standby/back up
equipment are accounted for as PP&E since they support the corporation's distribution
system reliability. No amortization is recorded on these items until they are put into service.Contributions in aid of construction
When an asset is received as a capital contribution, the asset is initially recognized at its fair
value, with the corresponding amount recognized as contributions in aid of construction.12
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(f) Property, plant and equipment (continued):
Gains and losses on disposal
Gains and losses on disposal of an item of property, plant and equipment are determined by
comparing the net proceeds from disposal with the carrying amount of the asset, and are
included in the statement of income and comprehensive income when the asset is disposed.
When an item of property, plant and equipment with related contributions in aid of
construction is disposed, the remaining contributions are recognized in full in the statement ofincome and comprehensive income.
(g) Borrowing costs:
The Corporation capitalizes interest expenses and other finance charges directly relating to
the acquisition, construction or production of assets that take a substantial period of time to
get ready for its intended use. Capitalization commences when expenditures are beingincurred, borrowing costs are being incurred and activities that are necessary to prepare the
asset for its intended use or sale are in progress. Capitalization will be suspended during
periods in which active development is interrupted. Capitalization should cease when
substantially all of the activities necessary to prepare the asset for its intended use or saleare complete.

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(h) Intangible assets:
Land rights
Payments to obtain rights to access land ("land rights") are classified as intangible assets.
These include payments made for easements, right of access and right of use over land for
which the Corporation does not hold title. Land rights are measured at cost less accumulatedamortization and accumulated impairment losses.
Computer software
Computer software that is acquired or developed by the Corporation, including software that
is integral to the functionality of equipment purchased, which has finite useful lives, is
measured at cost less accumulated amortization and accumulated impairment losses.Amortization
Amortization is recognized in profit or loss on a straight-line basis over the estimated useful
lives of intangible assets, other than goodwill, from the date that they are available for use.
Half of a year's amortization is taken for the first year. Amortization of useful lives for thecurrent and comparative years are:
Asset Useful life
Land rights 25 to 30 years
Computer software 3 years
13
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(i) Impairment of non-financial assets:
The Corporation conducts annual internal assessments of the values of equipment to
determine whether there are events or changes in circumstances that indicate that their
carrying amount may not be recoverable. Where carrying value exceeds its recoverable
amount, which is the higher of value in use and fair value less costs to sell, the asset is
written down accordingly. Where it is not possible to estimate the recoverable amount of an
individual asset, the impairment test is carried out on an asset's cash-generating unit, which
is the lowest group of assets to which the asset belongs for which there are separately
identifiable cash inflows that are largely independent of the cash inflows from other assets.
An impairment loss is charged to the statement of income and comprehensive income,except to the extent it reverses gains previously recognized in other comprehensive income.(j) Employee future benefits:
Pension plan
The employees of the Corporation participate in the Ontario Municipal Employees Retirement
System ("OMERS"). The Corporation also makes contributions to the OMERS plan on behalfof its employees. The plan has a defined benefit option at retirement
available to some

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employees, which specifies the amount of the retirement benefit plan to be
received by the
employees based on length of service and rates of pay. However, the plan is
accounted for
as a defined contribution plan as insufficient information is available to
account for the plan as
a defined benefit plan. The contribution payable in exchange for services
rendered during a
period is recognized as an expense during that period. The Corporation is
only one of a
number of employers that participates in the plan and financial information
provided to the
Corporation on the basis of the contractual agreements is usually
insufficient to measure the
Corporation's proportionate share in the plan's assets and liabilities for
defined benefitaccounting requirements.
Post-employment defined benefit plan
A defined benefit plan is a post-employment benefit plan other than a defined
contribution
plan. The Corporation's net obligation on behalf of its retired employees
unfunded life
insurance benefits is calculated by estimating the amount of future benefits
that are expectedto be paid out discounted to determine its present value.
The calculation is performed by a qualified actuary using the projected unit
credit method at
least every third year or when there are significant changes to workforce.
Defined benefit obligations are measured using the projected unit credit
method discounted
to its present value using yields available on high quality corporate bonds
that have maturitydates approximating the terms of the liabilities.
Remeasurements of the defined benefit obligation are recognized directly
within equity in
other comprehensive income. The remeasurements include actuarial gains and
losses.14
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(j) Employee future benefits (continued):
Post-employment defined benefit plan (continued)
Service costs are recognized in operating expenses and include current and
past servicecosts as well as gains and losses on curtailments.
Net interest expense is recognized in finance costs and is calculated by
applying the discount
rate used to measure the defined benefit obligation at the beginning of the
annual period to
the balance of the net defined benefit obligation, considering the effects of
benefit payments
during the period. Gains or losses arising from changes to defined benefits
or plancurtailment are recognized immediately in the statement of income and
comprehensive
income. Settlements of defined benefit plans are recognized in the period in
which thesettlement occurs.
Other long-term service benefits
Other employee benefits that are expected to be settled wholly within 12
months after the end

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of the reporting period are presented as current liabilities. Other employee benefits that are
not expected to be settled wholly within 12 months after the end of the reporting period are
presented as non-current liabilities and calculated using the projected unit credit method and
then discounted using yields available on high quality corporate bonds that have maturity
dates approximating to the expected remaining period to settlement.
(k) Payments in lieu of taxes payable:
The Corporation is a Municipal Electricity Utility ("MEU") for purposes of the payments in lieu
of taxes ("PILs") regime contained in the Electricity Act, 1998. As a MEU, the Corporation is
exempt from tax under the Income Tax Act (Canada) and the Corporations Tax Act (Ontario).
Under the Electricity Act, 1998, the Corporation is required to make, for each taxation year,
PILs to Ontario Electricity Financial Corporation ("OEFC"), commencing October 1, 2001.
These payments are calculated in accordance with the rules for computing taxable income
and taxable capital and other relevant amounts contained in the Income Tax Act (Canada)
and the Corporation Tax Act (Ontario) as modified by the Electricity Act, 1998, and relatedregulations.
Current and deferred tax
Provision in lieu of taxes is comprised of current and deferred tax. Current tax and deferred
tax are recognized in total income and other comprehensive income except to the extent that
it relates to items recognized directly in equity or regulatory deferral account balances (note10).
Current PILs are recognized on the taxable income or loss for the current year plus any
adjustment in respect of previous years. Current PILs are determined using tax rates and tax
laws that have been enacted or substantively enacted by the year-end date.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(k) Payments in lieu of taxes payable (continued):
Deferred tax assets and liabilities are recognized where the carrying amount of an asset or
liability differs from its tax base. The amount of the deferred tax asset or liability is measured
at the amount expected to be recovered from or paid to the taxation authorities. This amount
is determined using tax rates and tax laws that have been enacted or substantively enacted
by the year-end date and are expected to apply when the liabilities/(assets)
aresettled/(recovered). The Corporation recognized deferred tax arising from
temporarydifference on regulatory deferral account balances.
Recognition of deferred tax assets for unused tax losses, tax credits and

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deductible
temporary differences is restricted to those instances where it is probable that future taxable
profit will be available against which the deferred tax asset can be utilized.
At the end of each reporting period, the Corporation reassesses both recognized and
unrecognized deferred tax assets. The Corporation recognizes a previously unrecognized
deferred tax asset to the extent that it has become probable that future taxable profit willallow the deferred tax asset to be recovered.
(l) Finance income and finance costs:
Finance income is comprised of interest income on funds invested. Interest income is
recognized as it accrues in the statement of income and comprehensive income, using theeffective interest method.
Finance cost is comprised of interest payable on debt.
(m) Inventory:
Cost of inventory is comprised of direct materials, which typically consists of distribution
assets not deemed as major spares, unless purchased for specific capital projects in process
or as spare units. Costs, after deducting rebates and discounts, are assigned to individual
items of inventory on the basis of weighted average cost. Decommissioned assets that are
transferred to inventory are tested for impairment once they are removed from service and
placed in inventory. Inventory is recognized at the lower of cost and net realizable value. Net
realizable value is the estimated selling price in the ordinary course of business less the
estimated costs of completion and the estimated costs necessary to make the sale.(n) Leases:
At the inception of the contract, the Corporation assesses whether the contract is, or
contains, a lease based on whether the contract conveys the right to control the use of an
identified asset for a period of time, in exchange for consideration.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
2. Significant accounting policies (continued):
(n) Leases (continued):
The corporation recognizes a right-of-use ("ROU") assets and a lease liability at the lease
commencement date. ROU assets are initially measured at cost and subsequently carried at
cost less accumulated depreciation and impairments, if any. The initial cost of an ROU asset
equals the amount of the initial measurement of the corresponding lease liability, plus any
initial direct costs incurred to bring the assets into operation.
Lease liabilities are initially measured at the present value of lease payments that are not
paid at the commencement date. The lease payments are discounted using the

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rate implicitin the lease, or, if that rate cannot be readily determined, the Corporation's incremental
borrowing rate which reflects the Corporation's ability to borrow money over a similar term,
for an asset of similar value to the underlying asset, similar security or in a similar economic
environment. Variable lease payments that do not depend on an index or rate are notincluded in the measurement of the lease liability.
Lease liabilities are 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 Company changes its
assessment of whether it will exercise a purchase, extension or termination option.
When a lease liability is remeasured in this way, a corresponding adjustment is made to the
carrying amount of the ROU asset, or is recorded in profit or loss if the carrying amount of the
ROU asset has been reduced to zero. Payments under lease liabilities are apportioned
between interest expense and a reduction of the outstanding lease liability.
Where the Corporation is reasonably certain it will obtain ownership of the ROU asset before
the end of the lease term, the asset is depreciated over its useful life on a straight-line basis.
Otherwise, depreciation is calculated over the shorter period of the lease term and the asset's
useful life. The lease term includes periods covered by an option to extend if the Corporationis reasonably certain to exercise that option.
The Corporation has elected to apply the practical expedient not to recognize ROU assets
and lease liabilities for short-term leases that have a lease term of 12 months or less and
leases of low-value assets. The lease payments associated with these leases arerecognized as an expense on a straight-line basis over the lease term.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
3. Use of estimates and judgments:
The Corporation makes certain estimates and assumptions regarding the future. Estimates and
judgments are continually evaluated based on historical experience and other factors, including
expectations of future events that are believed to be reasonable under the circumstances. In the
future, actual experience may differ from these estimates and assumptions. The estimates and
assumptions that have a significant risk of causing a material adjustment to the carrying amounts
of assets and liabilities within the next financial year are discussed below.
Employee future benefits

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The cost of post-employment life insurance benefits are determined using actuarial valuations. An
actuarial valuation involves making various assumptions. Due to the complexity of the valuation,
the underlying assumptions and its long term nature, post-employment life insurance benefits are
highly sensitive to changes in these assumptions. All assumptions are reviewed at each reportingdate.
Payments in lieu of taxes payable
The Corporation is required to make payments in lieu of tax calculated on the same basis as
income taxes on taxable income earned and capital taxes. Significant judgment is required in
determining the provision for income taxes. There are many transactions and calculations
undertaken during the ordinary course of business for which the ultimate tax determination is
uncertain. The Corporation recognizes liabilities for anticipated tax audit issues based on the
Corporation's current understanding of the tax law. Where the final tax outcome of these matters
is different from the amounts that were initially recorded, such differences will impact the current
and deferred tax provisions in the period in which such determination is made.
Accounts receivable impairment
In determining the allowance for doubtful accounts, the Corporation considers historical loss
experience of account balances based on the aging and arrears status of accounts receivable
balances, observable changes in national or local economic conditions that correlate with default
on receivables, financial difficulty of the borrower, and it becoming
probable that the borrower willenter bankruptcy or financial re-organization.
Useful lives of depreciable assets
Depreciation expense is calculated based on estimates of the useful lives of equipment.
Management estimates the useful lives of the various types of assets using assumptions and
estimates of life characteristics of similar assets based on a long history of experience.18
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
4. Accounts receivable:
2020 2019
Residential and commercial energy and rentals $ 2,053,023 $ 2,167,669
Work at customers premises 175,202 151,022
Employee purchases 826 -
HST recoverable 220,055 144,860
Other miscellaneous receivables 458,329 697,229
Due from related party 30,303 53,646
2,937,738 3,214,426
Allowance for doubtful accounts (179,775) (99,382)
$ 2,757,963 $ 3,115,044
Due to their short-term natures, the carrying amounts of the various components of accountsreceivable approximate their fair values.

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5. Related party transactions:
(a) The ultimate parent:
The common shares of Ottawa River Power Corporation are owned by the City of Pembroke,
the Town of Mississippi Mills, the Township of Killaloe-Hagarty-Richards and the Township of
Whitewater Region, which all constitute local governments. Consequently, the Corporation is
exempt from some of the general disclosure requirements of IAS 24 with
relation totransactions with government-related parties, and has applied the
government-relateddisclosure requirements.
(b) Transactions with related parties:
The following summarizes the Corporation's related party transactions for the year. These
transactions are in the normal course of operations and are measured at the exchange value
(the amount of consideration established and agreed to by the related parties).19
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
5. Related party transactions (continued):
(b) Transactions with related parties (continued):
Ottawa River Energy Solutions Inc.
The Corporation has agreed to provide operating capital to Ottawa River Energy Solutions
Inc. Advances are due on demand. Interest on the operating loan is charged at the Royal
Bank of Canada prime rate, calculated semi-annually and payable on April 30. The loan
agreement does not provide for interest on payable amounts. The interest calculation
commenced January 1, 2003. At December 31, 2020, no amounts have been drawn
on theoperating loan (2019 - $Nil).
The Corporation provides services to Ottawa River Energy Solutions Inc., at cost. A summary
of amounts charged by the Corporation to the Ottawa River Energy Solutions
Inc. are asfollows:
2020 2019
Labour on customer premises $ 423,426 $ 610,658
Administration services 16,636 62,835
Rent and Service Charges 29,554 29,627
$ 469,616 $ 703,120
Included in the statement of income and comprehensive income is fibre services of $24,240
(2019 - $24,240) and solar generation of $34,578 (2019 - $17,983) paid to
Ottawa RiverEnergy Solutions Inc.
At December 31, 2020, the Corporation has an amount of $Nil due from (2019 -
$339,312due from) Ottawa River Energy Solutions Inc. The Corporation also has accounts payable
and accrued liabilities of $17,900 (2019 - $35,183) due to Ottawa River Energy Solutions Inc.
and accounts receivable include $30,303 (2019 - $53,646) due from Ottawa River Energy
Solutions Inc. Ottawa River Energy Solutions Inc. is affiliated by virtue of
common ownership.20

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Notes to Financial Statements (continued)
Year ended December 31, 2020
5. Related party transactions (continued):
(b) Transactions with related parties (continued):
Corporation of the City of Pembroke
The Corporation provides electricity and services to the principal shareholder, the City of
Pembroke. Electrical energy is sold to the City at the same prices and terms as other
electricity customers consuming equivalent amounts of electricity. A summary of amountscharged by the Corporation to the City of Pembroke are as follows:
2020 2019
Electrical energy $ 875,341 $ 953,013
Merchandising Jobbing 44,420 44,512
$ 919,761 $ 997,525
At December 31, 2020, accounts payable and accrued liabilities include $80,732 (2019 -
$45,799) due to the City of Pembroke and accounts receivable include $81,938 (2019 -$104,484) due from the City of Pembroke.
Dividends in the amount of $Nil (2019 - $193,101) have been paid to the City of Pembroke.
Property taxes and water and sewer charges paid to the City of Pembroke amounted to
$23,172 (2019 - $12,307). The Corporation incurred interest on the financing provided by theCity of Pembroke in the amount of $234,426 (2019 - $234,426).
(c) Key management personnel compensation:
The key management personnel of the Corporation has been defined as members of itsboard of directors and executive management team members.
2020 2019
Board of directors' fees $ 38,483 $ 38,805
Short-term employment benefits and salaries 572,256 578,858
Post-employment benefits 59,308 59,582
$ 670,047 $ 677,245
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
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6. Inventory:
Inventory consists of maintenance and construction materials amounting to $430,126 (2019 - $491,988).7. Property, plant and equipment:
Poles, Overhead Underground Assets
Substation and towers and conductors Underground conductor under
Land buildings fixtures and devices conduit and devices Services construction
TotalCost:
Balance, December 31, 2019 $ 258,350 $ 462,673 $ 3,945,562 $ 5,139,842 $ 1,236,713 $ 2,683,591 $ 3,907,690 $ 1,363,879 $ 18,998,300
Additions during the year - 50,192 2,025,406 226,900 49,766 265,109 206,769 101,662 2,925,804
Transfers during the year - - - - - - - (1,583,020) (1,583,020)
Disposals during the year - - - (4,670) (8,025) - (27,382) - (40,077)
Balance, December 31, 2020 258,350 512,865 5,970,968 5,362,072 1,278,454 2,948,700 4,087,077 (117,479) 20,301,007Accumulated depreciation
Balance, December 31, 2019 - 106,924 1,215,097 1,038,519 410,532 523,553 2,061,658 - 5,356,283
Depreciation for the year - 27,956 204,155 185,346 40,185 102,828 356,029 -

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916,499Disposals during the year - - - (4,670) (8,025) - (27,382) - (40,077)
Balance, December 31, 2020 - 134,880 1,419,252 1,219,195 442,692 626,381
2,390,305 - 6,232,705Net book value
Balance, December 31, 2019 $ 258,350 $ 355,749 $ 2,730,465 $ 4,101,323 $
826,181 $ 2,160,038 $ 1,846,032 $ 1,363,879 $ 13,642,017
Balance, December 31, 2020 258,350 377,985 4,551,716 4,142,877 835,762
2,322,319 1,696,772 (117,479) 14,068,302
During the year, no provision for the cost of funds used during construction
was capitalized. Included in additions is a right of use asset of $45,570
which is non-cash and is not included in the statement of cash flows.
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
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7. Property, plant and equipment (continued):
Poles, Overhead Underground Assets
Substation and towers and conductors Underground conductor under
Land buildings fixtures and devices conduit and devices Services construction
TotalCost:
Balance, December 31, 2018 $ 258,350 $ 458,483 $ 3,857,171 $ 4,772,325 $
1,081,904 $ 2,390,071 $ 3,677,721 $ - $ 16,496,025
Additions during the year - 4,190 147,245 367,517 154,809 444,627 507,664
1,363,879 2,989,931
Disposals during the year - - (58,854) - - (151,107) (277,695) - (487,656)
Balance, December 31, 2019 258,350 462,673 3,945,562 5,139,842 1,236,713
2,683,591 3,907,690 1,363,879 18,998,300Accumulated depreciation
Balance, December 31, 2018 - 87,696 1,021,043 857,721 351,519 382,685
2,004,079 - 4,704,743
Depreciation for the year - 19,228 194,054 180,798 59,013 140,868 335,274 -
929,235Disposals during the year - - - - - - (277,695) - (277,695)
Balance, December 31, 2019 - 106,924 1,215,097 1,038,519 410,532 523,553
2,061,658 - 5,356,283Net book value
Balance, December 31, 2018 $ 258,350 $ 370,787 $ 2,836,128 $ 3,914,604 $
730,385 $ 2,007,386 $ 1,673,642 $ - $ 11,791,282
Balance, December 31, 2019 258,350 355,749 2,730,465 4,101,323 826,181
2,160,038 1,846,032 1,363,879 13,642,01723
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
8. Intangible assets:
Intangible assets consist of the following:
Land Computer
rights software Total
Cost:
Balance, December 31, 2019 $ 2,748 $ 286,017 $ 288,765
Additions - 5,473 5,473
Disposals - (103,007) (103,007)
Balance, December 31, 2020 2,748 188,483 191,231
Accumulated amortization
Balance, December 31, 2019 2,010 260,750 262,760
Amortization for the year 335 15,937 16,272
Disposals - (103,007) (103,007)
Balance, December 31, 2020 2,345 173,680 176,025
Carrying amount
Balance, December 31, 2019 $ 738 $ 25,267 $ 26,005
Balance, December 31, 2020 403 14,803 15,206

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Land Computer
rights software Total
Cost:
Balance, December 31, 2018 $ 2,748 $ 269,356 $ 272,104
Additions - 16,661 16,661
Balance, December 31, 2019 2,748 286,017 288,765
Accumulated amortization
Balance, December 31, 2018 1,675 239,343 241,018
Amortization for the year 335 21,407 21,742
Balance, December 31, 2019 2,010 260,750 262,760
Carrying amount
Balance, December 31, 2018 $ 1,073 $ 30,013 $ 31,086
Balance, December 31, 2019 738 25,267 26,005
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
9. Payments in lieu of corporate income taxes:
PILs recognized in total income comprise the following:
2020 2019
Current tax expense:
Current year $ 28,438 $ 119,672
Deferred tax expense:
Origination and reversal of temporary differences 151,120 53,536
$ 179,558 $ 253,208
Statutory Canadian federal and provincial tax rates for the current year
comprise 15% (2019 -
15%) for federal corporate tax and 11.5% (2019 - 11.5%) for corporate tax in
Ontario. The PILs
expense varies from amounts which would be computed by applying the
Corporation's combinedstatutory income tax rate as follows:
2020 2019
Income before provision for PILs $ 706,090 $ 968,478
Statutory Canadian federal and provincial tax rate 26.50% 26.50%
Provision for PILs at statutory rate 187,114 256,647
Increase (decrease) in income tax resulting from:
Permanent differences 92 2,838
Regulatory (7,648) (6,277)
$ 179,558 $ 253,208
Effective tax rate 25.43% 26.10%
The movement in the deferred tax asset is as follows:
2020 2019
Opening balance, January 1 $ 845,115 $ 898,651
Recognized in regulatory deferral credits (151,120) (53,536)
Closing balance, December 31 $ 693,995 $ 845,115
25
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
9. Payments in lieu of corporate income taxes (continued):
Deferred tax assets are attributable to the following:
2020 2019
Property, plant and equipment $ 540,821 $ 708,938
Employee future benefits 153,174 136,177
$ 693,995 $ 845,115
The utilization of this tax asset is dependent on future taxable profits in

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excess of profits arising
from the reversal of existing taxable temporary differences. The Corporation
believes that this
asset should be recognized as it will be recovered through future services.
10. Regulatory deferral accounts:
All amounts deferred as regulatory account debit balances are subject to
approval by the OEB.
As such, amounts subject to deferral could be altered by the regulators.
Due to previous, existing or expected future regulatory articles or
decisions, the Corporation has
the following amounts expected to be recovered from customer (returned to
customers) in future
periods and as such regulatory deferral account balances are comprised of:
Balances
Dec 31, arising in Recovery/ Other Dec 31,
2019 the period reversal movements* 2020
Regulatory assets:
RARA approved
May 1, 2019 $ 287,349 $ (220,111) $ - $ - $ 67,238
Regulatory liabilities:
Regulatory liability for
deferred income taxes 845,115 (151,120) - - 693,995
RARA approved
May 1, 2016 40,524 2,193 - - 42,717
Retail settlement variances 706,745 (673,143) - - 33,602
Pole Attachment variance 128,154 - 207,839 - 335,993
1,720,538 (822,070) 207,839 - 1,106,307
Net regulatory liability $ (1,433,189) $ 601,959 $ (207,839) $ 797,163 $
(1,039,069)*Other movements represent reclassifications of balances.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
10. Regulatory deferral accounts (continued):
Carrying charges
Carrying charges are calculated monthly on the opening balance of the
applicable variance
account using a specified interest rate as outlined by the OEB. The
Corporation intends to seek
recovery of carrying charge income earned in future rate applications.
Regulatory asset recovery accounts ("RARA")
The RARA are comprised of the cumulative balances of regulatory assets and
regulatory
liabilities approved for disposition by the OEB, reduced by amounts settled
with customers
through billing of approved disposition rate riders. The RARA are subject to
carrying chargesfollowing the OEB prescribed methodology and rates.
In 2016 the Corporation received approval in its Cost of Service Application
to dispose of the
RARA balances from December 31, 2010 and May 1, 2012. These liabilities were
transferred to
the RARA effective May 1, 2016. The RARA amounts from May 1, 2013 were
approved fordisposal by the OEB.
The RARA approved May 1, 2016 have expired and the Corporation will apply for
disposal of the
remaining balances in the next Cost of Service Application to the OEB.

Corporation's name	Business number	Tax year end Year Month Day
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For rates effective May 1, 2019, the Corporation applied and was approved for a RARA for rates effective May 1, 2019 by the OEB. The RARA will be recovered from customers (returned to customers) through a variety of rate-riders implemented May 1, 2020 and ending April 30, 2021.Retail settlement variances ("RSVAs")

RSVAs are comprised of the variances between amounts charged by the Corporation to its customers, based on regulated rates, and the corresponding cost of non-competitive electricity service incurred by the Corporation. The settlement variances relate primarily to service charges, non-competitive electricity charges and the global adjustment. Accordingly, the Corporation has deferred the variances between the costs incurred and the related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. The balance for settlement variances continues to be calculated and attracts carrying charges in accordance with the OEB'sdirection.

Deferred income taxes

This regulatory liability account relates to the expected future electricity distribution rate adjustments for customers arising from timing differences in the recognition of future incometaxes.

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OTTAWA RIVER POWER CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2020

10. Regulatory deferral accounts (continued):

Other

Included in other are amounts related to pole attachment variance and to incremental capital module. The OEB approved an increase in the pole attachment charges effective January 1, 2019. The incremental capital module provides electricity distributors with a funding mechanism to address their capital needs. ORPC applied for incremental capital funding of $1,698,850 to build a new substation. The application was approved by the OEB in 2019. As of December 31, 2020, ORPC incurred $2,059,754 (2019 - $1,363,879) in construction costs related to the substation and recovered $211,883 (2019 - $84,776) from customers.

11. Accounts payable and accrued liabilities:

2020 2019

Hydro One $ 2,062,489 $ 2,591,636

Embedded generation 562,505 478,729

Trade payables 459,212 624,200

Accrued interest on long-term debt 162 77,735

Customer credit balances 524,637 538,989

Other accounts payable and accruals 1,176,237 416,683

Customer deposits 25,053 95,865

Due to relates parties 98,632 80,982

$ 4,908,927 $ 4,904,819

Due to its short-term nature, the carrying amount of the accounts payable and

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accrued liabilitiesapproximates its fair value.
12. Contributions in aid of construction:
The continuity of deferred contributions in aid of construction is as follows:
2020 2019
Deferred contributions, net, beginning of year $ 1,033,626 $ 745,012
Contributions in aid of construction received 101,293 312,300
Contributions in aid of construction recognized
as other revenue (28,856) (23,686)
Deferred contributions, net, end of year $ 1,106,063 $ 1,033,626
All contributions in aid of construction are cash contributions. There has
not been anycontributions of property, plant and equipment.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
13. Employee future benefits:
(a) Pension plan:
The employees of the Corporation participate in the Ontario Municipal
Employees Retirement
System ("OMERS"). Although the plan has a defined retirement benefit plan for
employees,
the related obligation of the Corporation cannot be identified. The OMERS
plan has several
unrelated participating municipalities and costs are not specifically
attributed to eachparticipant.
The plan specifies the amount of the retirement benefit to be received by the
employees
based on the length of service and rates of pay. The plan is financed by
equal contributions
from participating employers and employees, and by the investment earnings of
the fund. The
employer portion of amounts paid to OMERS during the year was $208,385 (2019 -
$192,175). The contributions were made for current service $204,363 (2019 -
$192,175) and
past service $4,022 (2019 - $Nil) and these have been recognized in total
income.
Each year, an independent actuary determines the funding status of OMERS
PrimaryPension Plan by comparing the actuarial value of invested assets to
the
estimated present
value of all pension benefits that members have earned to date. The most
recent actuarial
valuation of the Plan was conducted at December 31, 2020. The results of this
valuation
disclosed total actuarial liabilities of $111.8 billion (2019 - $106.4
billion) in respect of benefits
accrued for service with actuarial assets at that date of $108.6 billion
(2019 - $103.0 billion),
indicating an actuarial deficit of $3.2 billion (2019 - $3.4 billion).
Because OMERS is a
multiemployer plan, any pension plan surpluses or deficits are a joint
responsibility of Ontario
municipal organizations and their employees, as a result, the Corporation
does not recognizeany share of the OMERS pension surplus or deficit.
(b) Post-employment life insurance plan:
The Corporation provides unfunded life insurance benefits on behalf of its

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retired employees.
These benefits are provided through a group defined benefit plan. The Corporation has
reported its share of the defined benefit costs and related liabilities, as calculated by an
actuary, in these financial statements. The accrued benefit liability and the expense for the
year ended December 31, 2020 is based on results determined by actuarial valuation as atDecember 31, 2019.
The plan is exposed to a number of risks, including:
? Interest rate risk: decreases/increases in the discount rate used (high quality corporatebonds) will increase/decrease the defined benefit obligation.
? Longevity risk: changes in the estimation of mortality rates of current and formeremployees.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
13. Employee future benefits (continued):
(b) Post-employment life insurance plan (continued):
Information about the group unfunded defined benefit plan as a whole and changes in the
present value of the unfunded defined benefit obligation and the accrued benefit liability areas follows:
2020 2019
Defined benefit obligation, beginning of year $ 377,700 $ 192,672
Amounts recognized in net income:
Current service cost 4,497 4,712
Interest on cost obligation 11,994 5,741
16,941 10,453
Benefit payments (26,291) (24,211)
Projected defined benefit obligation before
actuarial valuation 367,900 178,914
Actuarial loss recognized in other comprehensive income 56,942 198,786
Defined benefit obligation, end of year $ 424,842 $ 377,700
Significant actuarial assumptions for the measurement of the defined benefit obligation as atDecember 31 are as follows:
2020 2019
Discount rate 2.50% 3.25%
Rate of compensation increase 2.65% 2.65%
Retirement age Variable Variable
Sensitivity analysis for each significant actuarial assumption to which the Corporation isexposed is as follows:
? 1% decrease in the discount rate increases the defined benefit obligation by $88,400.
? 1% increase in the discount rate decreases the defined benefit obligation by $66,500.
? Change with 1-year greater life expectancy decrease the defined benefit obligationby $14,200.
? Change with 1-year increase in retirement age assumption decrease the defined benefitobligation by $1,000.
? The expected average remaining service lifetime at December 31, 2020 was 18.2 years(2019 - 18.2 years).
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)

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Year ended December 31, 2020
14. Long-term debt:
2020 2019
5.37182% Promissory note payable to the Corporation
of the City of Pembroke, due May 1, 2022 $ 4,364,000 $ 4,364,000
5.37182% Promissory note payable to the Corporation
of the Village of Beachburg, due May 1, 2022 147,000 147,000
5.37182% Promissory note payable to the Corporation
of the Township of Killaloe, Hagarty and Richards,
due May 1, 2022 172,348 172,348
5.37182% Promissory note payable to the Corporation
of the Town of Mississippi Mills, due May 1, 2022 902,490 902,490
2.56% Promissory note payable in blended monthly
payments of $ 7,112 to Ontario Infrastructure and
Lands Corporation, due June 30, 2050 1,765,930 -
7,351,768 5,585,838
Less: current portion of long-term debt 41,664 -
$ 7,310,104 $ 5,585,838
In January 2019 the Corporation obtained a construction loan from Ontario
Infrastructure and
Lands Corporation in order to fund the construction of a new substation in
Almonte. The
agreement provided two credit facilities for a total committed amount of
$1,785,850. The facilities
are a short term loan which is a non-revolving floating rate construction
loan and a term loan
which is a non-revolving fixed rate term loan. In fiscal 2019 the Corporation
received proceeds of
$1,219,507 against the non-revolving construction loan. The shot term
facility matured at the
earlier of project completion or June 2020. Upon completion of the project
the short term loan
was converted to the term loan with a maturity date of June 30, 2050.
Interest on promissory notes is calculated annually and payable quarterly to
the shareholders.31
OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
15. Capital stock:
(a) Authorized:
Unlimited number of common shares
Unlimited number of non-cumulative special shares
Unlimited number of non-voting, non-cumulative Class A special shares,
redeemable at onedollar per share
Unlimited number of non-voting, non-cumulative Class B special shares,
redeemable at onedollar per share
Unlimited number of non-voting, non-cumulative Class C special shares,
redeemable at onedollar per share
Unlimited number of non-voting, non-cumulative Class D special shares,
redeemable at onedollar per share
Articles of amendment were issued on October 17, 2014 to authorize the Class
A, B, C and D
special shares. Class A, B, C and D special shares were issued on January 15,
2015.Dividends on special shares are payable at the discretion of the Board
of
Directors.(b) Issued:

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Notes to the financial statements

As at December 31, 2020, the common shares of the Corporation are held as follows:Common Percentage
shares ownership
Corporation of the City of Pembroke 4,364 78.38%
Corporation of the Town of Mississippi Mills 888 15.94%
Corporation of the Township of Killaloe, Hagarty and Richards 169 3.04%
Corporation of the Township of Whitewater Region 147 2.64%
5,568 100.00%
No movement in common share capital has occurred during 2020 or 2019.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
15. Capital stock (continued):
(b) Authorized (continued):
As at December 31, 2020, the special shares of the Corporation are held as follows:Special
shares Class
Corporation of the City of Pembroke 4,364 A
Corporation of the Town of Mississippi Mills 888 B
Corporation of the Township of Killaloe, Hagarty and Richards 169 C
Corporation of the Township of Whitewater Region 147 D
5,568
The special shares were issued on January 15, 2015. There was no movement on specialshare capital during 2020 or 2019.
(c) Dividends per share:
2020 2019
Class A special shares $ - $ 44.25
Class B special shares - 73.41
Class C special shares - 73.29
Class D special shares - 52.88
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
16. Commitments:
City of Pembroke
The Corporation rents its premises in Pembroke, Ontario, from the Corporation of The City of
Pembroke under the terms of a ten-year operating lease at an annual rental of $12. The lease
contained an option which allowed the lessee to purchase the property on or before December 1,
2009, at a cost of three hundred and sixty thousand, five hundred and eighty-three dollars
($360,583) together with any assessable environmental clean-up costs. The Corporation is
currently in discussions with the Corporation of the City of Pembroke regarding the status of thislease.
Mississippi River Power Corporation
The Corporation rents office premises from Mississippi River Power Corporation at a monthly cost
of $10,438. The lease expires on September 30, 2025.
The Corporation rents substation premises from Mississippi River Power Corporation at amonthly cost of $575. The lease expires on December 31, 2026.
Runge Stationers

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The Corporation rents a postage machine premises from Runge Stationers at a
monthly cost of$548. The lease expires on June 1, 2021.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
17. Contingencies:
(a) Insurance claims:
The Corporation is a member of the Municipal Electric Association Reciprocal
Insurance
Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a
group ofpersons formed for the purpose of exchanging reciprocal contracts of
indemnity or interinsurance
with each other. MEARIE is licensed to provide general liability insurance to
member electric utilities.
Insurance premiums charged to each municipal electric utility consist of a
levy per thousand
dollars of service revenue subject to a credit or surcharge based on each
electric utility's
claims experience. Effective January 1, 2001, coverage is provided to a level
of $20 millionper incident.
No provision has been made for these potential liabilities as the Corporation
expects thatthese claims are adequately covered by its insurance.
18. Revenue:
2020 2019
Revenue from contracts with customers
Power recovery $ 26,611,504 $ 23,310,296
Distribution:
Residential service 3,024,238 3,086,650
General service 864,436 911,048
Larger users 935,864 954,104
4,824,538 4,951,802
$ 31,436,042 $ 28,262,098
2020 2019
Other operating revenue:
Late payment charges $ 29,688 $ 47,921
Property and equipment rent 83,947 44,436
Change of occupancy and connection fees 46,500 48,983
Merchandising jobbing 440,859 671,758
Interest 5,455 12,967
Billing and collection charges 7,301 10,785
Gain on disposal of property, plant and equipment - 43,872
$ 613,750 $ 880,722
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
19. Expenses by nature:
Distribution operation and maintenance
2020 2019
Materials, supplies, small tools recovery $ (54,686) $ (33,658)
Salaries and benefits 1,018,835 986,773
Training and travel 10,908 59,900
Office and general 55,815 2,127
Utilities 45,718 41,317
Insurance 5 3,145

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Property taxes 23,172 12,307
$ 1,099,767 $ 1,071,911
Community relations
2020 2019
Advertising $ 35,251 $ 28,478
Safety program 1,412 35,779
$ 36,663 $ 64,257
Billing and collecting
2020 2019
Smart meter reading and operations $ 55,013 $ 52,758
Postage 112,995 116,709
Salaries and benefits 487,242 382,247
Information technology 60,738 60,576
Office and general 72,812 31,620
Bad debts 57,859 105,151
Collection agency costs (1,978) 9,948
$ 844,681 $ 759,009
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
19. Expenses by nature (continued):
General and administrative
2020 2019
Salaries and benefits $ 759,607 $ 715,736
Memberships, fees and dues 87,471 88,063
Legal 12,878 20,330
Audit 49,953 57,222
Professional Services 4,200 -
Building maintenance 96,494 134,332
Advertising 4,720 5,200
Regulatory 120,822 116,010
Information technology 19,145 19,225
Telephone 42,988 40,604
Insurance 35,105 29,852
Bank charges 21,615 25,051
Office supplies and materials 34,255 53,610
$ 1,289,253 $ 1,305,235
20. Financial risk management:
As part of its operations, the Corporation carries out transactions that expose it to financial risks
such as credit, liquidity and market risks. The following is a discussion of risks and related
mitigation strategies that have been identified by the Corporation for financial instruments. This is
not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks identified.(a) Credit risk:
Credit risk is the risk that one party to a financial instrument will cause a loss for the other
party by failing to pay for its obligation. The maximum credit exposure is limited to the
carrying amount of cash, accounts receivable, and unbilled revenue presented on thebalance sheet.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)

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Notes to the financial statements

Year ended December 31, 2020

20. Financial risk management (continued):

(a) Credit risk (continued):

The Corporation limits its exposure to credit loss by placing its cash with a high credit quality financial institution. The Corporation maintains cash with two major financial institutions.

Eligible deposits per financial institution are insured to a maximum basic insurance level of $100,000, including principal and interest by the Canada Deposit Insurance Corporation. The Corporation is exposed to credit risk related to accounts receivable and unbilled revenue arising from its day-to-day electricity and service revenue. Exposure to credit risk is limited due to the Corporation's large and diverse customer base. The Corporation has approximately 11,000 customers, the majority of which are residential. No single customer accounts for revenue in excess of 10% of total revenue. The Corporation limits its credit risk by collecting deposits, following collection policies, monitoring accounts receivable aging, and utilizing collection agencies. The Ontario Energy Board has prescribed certain rules for the payment of deposits by customers. Although these rules limit the risk of the Corporation, no deposits are required by customers who have shown good payment history for the previous 12-month period. The Corporation does not have any material accounts receivable balances greater than 90 days outstanding. The Corporation believes that its accounts receivablerepresent a low credit risk.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in net income.

The provision is based on account age and customer standing. Subsequent recoveries ofreceivables previously provisioned are credited to net income.

The value of accounts receivable, by age, and the related bad debt provision are presented in the following table. Unbilled revenue which is not included in the table below is considered allcurrent.

	2020	2019
Under 30 days	$ 2,535,849	$ 2,963,895
30 to 60 days	90,554	75,169
61 to 90 days	66,513	58,595
Over 90 days	244,822	116,767
	2,937,738	3,214,426
Allowance for doubtful accounts	(179,775)	(99,382)
Total accounts receivable	$ 2,757,963	$ 3,115,044

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OTTAWA RIVER POWER CORPORATION

Notes to Financial Statements (continued)

Year ended December 31, 2020

20. Financial risk management (continued):

(b) Liquidity risk:

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Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as
they come due. 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 $1,000,000 line of credit and monitors cash
balances to ensure that sufficient levels of liquidity are on hand to meet financialcommitments as they come due.
0 to 3 3 months 1 year to
months to 1 year 2 years Thereafter
Accounts payable and
accrued liabilities $ 4,908,927 $ - $ - $ -
Long-term debt 10,056 31,608 5,627,502 1,682,602
Total, December 31, 2020 $ 4,918,983 $ 31,608 $ 5,627,502 $ 1,682,602
0 to 3 3 months 1 year to
months to 1 year 2 years Thereafter
Accounts payable and
accrued liabilities $ 4,904,819 $ - $ - $ -
Loan payable 1,222,312 - - -
Line of credit 400,000
Long-term debt 74,930 175,035 300,060 5,585,838
Total, December 31, 2019 $ 6,602,061 $ 175,035 $ 300,060 $ 5,585,838
(c) Market risk:
The Corporation is not exposed to significant market risk given they do not have investments
in foreign currency, and have minimal investment in interest bearing instruments.(d) Impact of COVID-19:
In March 2020, the COVID-19 outbreak was declared a pandemic by the World HealthOrganization. This resulted in governments worldwide, enacting emergency
measures to
combat the spread of the virus. Beyond COVID-19 restrictions at operating locations the
COVID-19 pandemic has not had a significant impact on the Corporation to date. The
situation is dynamic and continuously evolving, and ultimately financial impact of the
pandemic on the Corporation remains unknown as of the date of the approval of thesefinancial statements.
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OTTAWA RIVER POWER CORPORATION
Notes to Financial Statements (continued)
Year ended December 31, 2020
20. Financial risk management (continued):
(e) Changes in risk exposure:
Other than described in note 20(d), there has been no change to the Corporation's riskexposure from 2019
21. Energy purchase:
The Corporation is dependent on Hydro One for a significant portion of the electricity it
purchases. The amount owing to Hydro One at December 31, 2020 is $2,062,489
(2019 -$2,591,635). Included in cost of power in the statement of income and

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comprehensive income is
$25,908,846 (2019 - $22,039,605) purchased from Hydro One.
22. Bank indebtedness, bankers' acceptances and letters of credit:
The Corporation has a bilateral demand line of credit for $1,000,000 with a
Canadian chartered
bank. The line of credit bears interest at the bank's prime rate. At December
31, 2020, noamounts had been drawn on the line of credit (2019 - $400,000).
23. Capital management:
The Corporation considers its capital to be its long-term debt, capital stock
and retained earnings.
The Corporation's main objectives when managing capital are to: i) ensure
sufficient liquidity to
maintain and improve its electricity distribution system, support its
financial obligations and
execute its operating and strategic plans; ii) minimize the cost of capital
while taking into
consideration current and future industry, market and economic risks and
conditions; iii) maintain
an optimal capital structure that provides necessary financial flexibility
and considers recoveries
of financing charges permitted by the OEB, while also ensuring compliance
with any financial
covenants, and iv) provide an adequate return to its shareholders.
The Corporation relies on its cash flow from operations to fund its dividend
distributions to itsshareholders.

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
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- 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			526,532	A

Add:

	Line	Amount		
Provision for income taxes – current	101	28,438		
Provision for income taxes – deferred	102	151,120		
Amortization of tangible assets	104	903,915		
Non-deductible meals and entertainment expenses	121	347		
Other reserves on lines 270 and 275 from Schedule 13	125	99,382		
Reserves from financial statements – balance at the end of the year	126	604,617		
Subtotal of additions		1,787,819	1,787,819	

Other additions:

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	CIAC increase	101,293
	Total of column 2	101,293

	Line	Amount		
Total of column 2	296	101,293		
Subtotal of other additions	199	101,293	101,293	D
Total additions	500	1,889,112	1,889,112	
Amount A **plus** line 500			2,415,644	B

Deduct:

	Line	Amount		
Capital cost allowance from Schedule 8	403	1,370,200		
Other reserves on line 280 from Schedule 13	413	179,775		
Reserves from financial statements – balance at the beginning of the year	414	477,082		
Subtotal of deductions		2,027,057	2,027,057	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Amortization of contributions in aid of construction	28,856
2	FT in regulatory liabilities	151,120
3	Election - 13(7.4)	101,293
	Total of column 2	281,269

	Line	Amount		
Total of column 2	396	281,269		
Subtotal of other deductions	499	281,269	281,269	E
Total deductions	510	2,308,326	2,308,326	
Net income (loss) for income tax purposes (amount B **minus** line 510)			107,318	C

Enter amount C on line 300 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
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- 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

Ontario basic income tax (from Schedule 500) 270

Ontario small business deduction (from Schedule 500) 402

Subtotal (line 270 **minus** line 402) ► 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) 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") 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") 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") 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) 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) 290

(if a credit, enter amount in brackets) Include this amount on line 255.

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

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
Ottawa River Power Corporation	87176 4072 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	Buildings	367,439	50,192	50,192				0	417,631
2.	2	Electrical distributing equipement	3,072,300						0	3,072,300
3.	8	Equipment	361,121	84,526	84,526				0	445,647
4.	10	Computer Hardware & Vehicles	258,872						0	258,872
5.	45	Computer Hardware	6,695	32,757	32,757				0	39,452
6.	47	Electrical distributing equipment	7,091,364	2,555,375	2,555,375				0	9,646,739
7.	50	Computer hardware post March 2007	3,073						0	3,073
8.	14.1		1,238,118						0	1,238,118
9.	12	Software		5,473					0	5,473
		Totals	12,398,982	2,728,323	2,722,850					15,127,305

	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	Buildings		50,192	25,096		4	0	0	17,709	399,922
2.	2	Electrical distributing equipem					6	0	0	184,338	2,887,962

	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
3.	8	Equipment		84,526	42,263		20	0	0	97,582	348,065
4.	10	Computer Hardware & Vehicle					30	0	0	77,662	181,210
5.	45	Computer Hardware		32,757	16,379		45	0	0	25,124	14,328
6.	47	Electrical distributing equipme		2,555,375	1,277,688		8	0	0	873,954	8,772,785
7.	50	Computer hardware post Marc					55	0	0	1,690	1,383
8.	14.1						5	0	0	86,668	1,151,450
9.	12	Software					100	0	0	5,473	
		Totals		2,722,850	1,361,426					1,370,200	13,757,105

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
Ottawa River Power Corporation	87176 4072 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.	Ottawa River Energy Solutions Inc.		86613 9025 RC0001	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)

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SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 RC0001	2020-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on an amalgamation or the wind-up of a subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, *Summary of Dispositions of Capital Property*. The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

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 $
Reserve for doubtful debts	X	110 99,382	115	179,775	99,382	120 179,775
Reserve for undelivered goods and services not rendered		130	135			140
Reserve for prepaid rent		150	155			160
Reserve for refundable containers		190	195			200
Reserve for unpaid amounts		210	215			220
Other tax reserves		230	235			240
Totals		270 99,382	275	179,775	99,382	280 179,775

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*, as an addition. The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

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	Future Employee Benefits	377,700		424,842	377,700	424,842
2						
	Reserves from Part 2 of Schedule 13	99,382		179,775	99,382	179,775
	Totals	477,082		604,617	477,082	604,617

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.

Attached Schedule with Total

Part 1 – Financial statement reserves – Federal – Add

Title Part 1 – Financial statement reserves – Federal – Add

Description	Operator (Note)	Amount
Post Retirement Benefits - AP		
230600 OPEB Liability	+	424,842 00
	+	
	Total	424,842 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 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
Ottawa River Power Corporation	87176 4072 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	47,142	1245045-01			

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 . . . . 47,142 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 47,142 B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") 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	Ottawa River Power Corporation	87176 4072 RC0001	1	500,000	100.0000	500,000	
2	Ottawa River Energy Solutions Inc.	86613 9025 RC0001	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
Ottawa River Power Corporation	87176 4072 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			
Capital stock (or members' contributions if incorporated without share capital)	103	5,591,406		
Retained earnings	104	3,923,266		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108	7,351,768		
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)		16,866,440 ▶	16,866,440	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)			16,866,440 A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121	693,995	
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)		693,995 ►	693,995 B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		16,172,445

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	
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	

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)		16,172,445 C
Deduct: Investment allowance for the year (line 490)		D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	16,172,445

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)						
16,172,445	x	Taxable income earned in Canada **610**	1,000	=	**Taxable capital employed in Canada** **690**	16,172,445
		Taxable income	1,000			

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
Due to ORES		
LT debt	+	7,310,104 00
Current portion of long term debt	+	41,664 00
	+	
	Total	7,351,768 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
Ottawa River Power Corporation	87176 4072 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	Corporation of the City of Pembroke	121936140RC0001			79.000	79.000
2	Corporation of the Town of Mississippi Mills	866266653RC0001			16.000	16.000
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
Ottawa River Power Corporation	87176 4072 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	24,400,539
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	2,308,691
Total assets (total of lines 112 to 116)		26,709,230
Total revenue of the corporation for the tax year **	142	32,443,913
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	1,109,729
Total revenue (total of lines 142 to 146)		33,553,642

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

Net income/loss per financial statements *			210	526,532
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	28,438		
Provision for deferred income taxes (debits)/cost of future income taxes	222	151,120		
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		179,558		179,558 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			
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	382			
383	384			
385	386			
387	388			
389	390			
Subtotal				B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	706,090

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** ______

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** ______

Amount from line 520 ______ 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 ______ x Number of days in the tax year after June 30, 2010 366 / Number of days in the tax year 366 x 2.7 % = ______ 2

Subtotal (amount 1 **plus** amount 2) . . . . ______ 3

Gross CMT: amount on line 3 above x OAF ** . . . . **540** ______

Deduct:

Foreign tax credit for CMT purposes *** . . . . **550** ______

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . ______ D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) . . . . ______

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) 1

For a corporation that is not a life insurance corporation:

CMT after foreign tax credit deduction (amount D from Part 3) . . 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: 6

Subtotal (if negative, enter "0") ► N

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) . . . .

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") ► 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 ☒

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.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Ottawa River Power Corporation	87176 4072 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	Ottawa River Energy Solutions Inc.	86613 9025 RC0001	2,308,691	1,109,729
		Total	450 2,308,691	550 1,109,729

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

Line 996 Summary – Amended Tax Return – Description of Changes

Taxation year end 2017-12-31
Filing date of the amended tax return . . . .
Abbreviated description . . . .

996 Description of changes (*Maximum 500 lines*)

1. Taxation return has been amended to incorporate changes as a result of the
2. reassessment of the December 31, 2015 taxation return by the Ministry of
3. Finance and subsequent amendment of the December 31, 2016 taxation return
4. The changes can be summarized as follows:
5. - Schedule 13S has been completed to report the opening balance of employee
6. future benefits which agrees to the closing balance on the amended 2016
7. taxation return. The closing balance reports the amount of employee future
8. benefits reported in the 2017 financial statements.
9. - Schedule 1 includes an addback for 50% of meals and entertaiment deducted
10. in the 2016 financial statements.
11. - Taxable capital of the prior year has been updated to agree with the
12. adjustments made on the amended 2016 taxation return. As a result the
13. corporation is entitled to a portion of the small business deduction.
14. - Schedule 33 has been updated to reflect the correct amounts as reported on
15. the 2017 financial statements.
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Appendix C – PDF of PILs Model

Ontario Energy Board

Income Tax/PILs Workform for 2022 Filers

Version 1.00

Utility Name	Ottawa River Power Corporation
Assigned EB Number	EB-2021-0052
Name and Title	Jeffrey Roy, Chief Financial Officer
Phone Number	(613)732-3687x227
Email Address	jroy@orpowercorp.com
Date	30-Sep-21
Last COS Re-based Year	**2016**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Income Tax/PILs Workform for 2022 Filers

Ontario Energy Board

Income Tax/PILs Workform for 2022 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	**-454,628**	
Test Year - Payments in Lieu of Taxes (PILs)	T0	**-**	
Test Year - Grossed-up PILs	T0	**-**	
Effective Federal Tax Rate	T0	**12.9%**	
Effective Ontario Tax Rate	T0	**8.6%**	
Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	443,101	
Taxable Income	T1	-11,527	
Difference	calculated	-454,628	as above

Income Tax/PILs Workform for 2022 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	Y	
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	

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Income Tax/PILs Workform for 2022 Filers

			Test Year	Bridge Year	
Rate Base		S	**$ 13,282,397**	**$ 12,817,314**	

Return on Ratebase

			Test Year	
Deemed ShortTerm Debt %	4.00%	T	$ 531,296	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$ 7,438,142	*X = S * U*
Deemed Equity %	40.00%	V	$ 5,312,959	*Y = S * V*
Short Term Interest Rate	1.75%	Z	$ 9,298	*AC = W * Z*
Long Term Interest	2.73%	AA	$ 203,061	*AD = X * AA*
Return on Equity (Regulatory Income)	8.34%	AB	**$ 443,101**	*AE = Y * AB* T1
Return on Rate Base			**$ 655,460**	*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?	Yes	Yes	Yes
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.*	No	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

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Income Tax/PILs Workform for 2022 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**
Federal income tax							
General Corporate Rate	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%
Adjusted Federal Rate	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%
Federal Income Tax	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%
Combined Federal and Ontario	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
Ontario Small Business Limit	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%
Ontario Small Business Rate	4.50%	4.50%	3.50%	3.50%	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 2022 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	$ 107,318	**A**
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	**B**			
	Federal tax rate (Maximum 15%)	**C**			
	Combined tax rate (Maximum 26.5%)			0.00%	**D = B+C**
Total Income Taxes				**$ -**	**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				**$ -**	**I = E - H**

Ontario Energy Board

Income Tax/PILs Workform for 2022 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)**	706,090		706,090
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	903,915		903,915
Amortization of intangible assets	106			0
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			0
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	347		347
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	99,382		99,382
Reserves from financial statements – balance at the end of the year	126	604,617		604,617
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
	295			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))		101,293		101,293
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
				0

				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**1,709,554**	**0**	**1,709,554**
Deductions:				
Gain on disposal of assets per financial statements	401			0
Non-taxable dividends under section 83	402			0
Capital cost allowance from Schedule 8	403	1,370,200		1,370,200
Terminal loss from Schedule 8	404			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413	179,775		179,775
Reserves from financial statements - balance at beginning of year	414	477,082		477,082
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			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 Contributions in Aid of Construction	395	28,856		28,856
Deferred Tax Recognized in Regulatory Deferral Credits	395	151,120		151,120
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received		101,293		101,293
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
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
				0
Closing Regulatory Accounts				0
Capital Assets Additions Included in Regulatory Balance				0
18(9.1) deduction (1/9)				0
Amortization Deffered Revenue				0
				0
				0
				0
Total Deductions		**2,308,326**	**0**	**2,308,326**
Net Income for Tax Purposes		**107,318**	**0**	**107,318**
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		**107,318**	**0**	**107,318**

Ontario Energy Board

Income Tax/PILs Workform for 2022 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	B4

Ontario Energy Board

Income Tax/PILs Workform for 2022 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year	Working Paper Reference
1	Buildings, Distribution System (acq'd post 1987)	$ 399,922		$ 399,922	B8
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]			$ -	B8
2	Distribution System (acq'd pre 1988)	$ 2,887,962		$ 2,887,962	B8
3	Buildings (acq'd pre 1988)			$ -	B8
6	Certain Buildings; Fences			$ -	B8
8	General Office Equipment, Furniture, Fixtures	$ 348,065		$ 348,065	B8
10	Motor Vehicles, Fleet	$ 181,210		$ 181,210	B8
10.1	Certain Automobiles			$ -	B8
12	Computer Application Software (Non-Systems)			$ -	B8
13_1	Lease # 1			$ -	B8
13_2	Lease # 2			$ -	B8
13_3	Lease # 3			$ -	B8
13_4	Lease # 4			$ -	B8
14	Limited Period Patents, Franchises, Concessions or Licences			$ -	B8
14.1	Eligible Capital Property (acq'd pre 2017)	$ 1,151,450		$ 1,151,450	B8
14.1	Eligible Capital Property (acq'd post 2016)			$ -	B8
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage			$ -	B8
42	Fibre Optic Cable			$ -	B8
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -	B8
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -	B8
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	$ 14,328		$ 14,328	B8
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			$ -	B8
47	Distribution System (acq'd post Feb 22/05)	$ 8,772,785		$ 8,772,785	B8
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	$ 1,383		$ 1,383	B8
95	CWIP			$ -	B8
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
	SUB-TOTAL - UCC	13,757,105	0	13,757,105	

Income Tax/PILs Workform for 2022 Filers

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)			0	B13
Tax reserves not deducted for accounting purposes				
Reserve for doubtful accounts ss. 20(1)(l)	179,775		179,775	B13
Reserve for undelivered goods and services not rendered ss. 20(1)(m)			0	B13
Reserve for unpaid amounts ss. 20(1)(n)			0	B13
Debt & share issue expenses ss. 20(1)(e)			0	B13
Other tax reserves			0	B13
			0	
			0	
			0	
			0	
			0	
Total	**179,775**	**0**	**179,775**	
Financial Statement Reserves (not deductible for Tax Purposes)				
General reserve for inventory obsolescence (non-specific)			0	B13
General reserve for bad debts	179,775		179,775	B13
Accrued Employee Future Benefits:			0	B13
- Medical and Life Insurance			0	B13
-Short & Long-term Disability			0	B13
-Accmulated Sick Leave			0	B13
- Termination Cost			0	B13
- Other Post-Employment Benefits	424,842		424,842	B13
Provision for Environmental Costs			0	B13
Restructuring Costs			0	B13
Accrued Contingent Litigation Costs			0	B13
Accrued Self-Insurance Costs			0	B13
Other Contingent Liabilities			0	B13
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0	B13
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0	B13
Other			0	B13
			0	
			0	
Total	**604,617**	**0**	**604,617**	

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Income Tax/PILs Workform for 2022 Filers

PILS Tax Provision - Bridge Year

Wires Only

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate		Reference	Wires Only	
Regulatory Taxable Income						B1	$ 90,786	**A**
Ontario (Max 11.5%)	11.5%	7.9%	$ 7,151	7.9%	**B**			
Federal (Max 15%)	15.0%	12.4%	$ 11,240	12.4%	**C**			
Combined effective tax rate (Max 26.5%)							20.26%	**D = B + C**
Total Income Taxes							**$ 18,391**	**E = A * D**
Investment Tax Credits								**F**
Miscellaneous Tax Credits								**G**
Total Tax Credits							**$ -**	**H = F + G**
Corporate PILs/Income Tax Provision for Bridge Year							**$ 18,391**	**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 2022 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	**(A + 101 + 102)**		700,000
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		924,213
Amortization of intangible assets	106		
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		
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		250
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	179,775
Reserves from financial statements- balance at end of year	126	B13	604,617
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		

Adjusted Taxable Income - Bridge Year

Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			194,750
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			**1,903,605**
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	1,501,121
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	179,775
Reserves from financial statements - balance at beginning of year	414	B13	604,617
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions			

Ontario Energy Board

Income Tax/PILs Workform for 2022 Filers

Adjusted Taxable Income - Bridge Year

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 Contributions in Aid of Construction	395		32,556
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			194,750
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
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	**2,512,819**
Net Income for Tax Purposes		calculated	**90,786**
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	**90,786**

Ontario Energy Board

Income Tax/PILs Workform for 2022 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	0	
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

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	T4

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Income Tax/PILs Workform for 2022 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)	Working Paper Reference
1	Buildings, Distribution System (acq'd post 1987)	H8	$ 399,922	$ 10,343						$ 410,265	$ -	$ -	0.50	$ -	$ 5,172	4%			$ 16,204		$ 394,061	T8
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	6%			$ -		$ -	T8
2	Distribution System (acq'd pre 1988)	H8	$ 2,887,962							$ 2,887,962	$ -	$ -		$ -	$ -	6%			$ 173,278		$ 2,714,684	T8
3	Buildings (acq'd pre 1988)	H8	$ -							$ -	$ -	$ -		$ -	$ -	5%			$ -		$ -	T8
6	Certain Buildings; Fences	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -	T8
8	General Office Equipment, Furniture, Fixtures	H8	$ 348,065	$ 36,561						$ 384,626	$ -	$ -	0.50	$ -	$ 18,281	20%			$ 73,269		$ 311,357	T8
10	Motor Vehicles, Fleet	H8	$ 181,210	$ 13,602						$ 194,812	$ -	$ -	0.50	$ -	$ 6,801	30%			$ 56,403		$ 138,409	T8
10.1	Certain Automobiles	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -	T8
12	Computer Application Software (Non-Systems)	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	100%			$ -		$ -	T8
13_1	Lease # 1	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
13_2	Lease # 2	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
13_3	Lease # 3	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
13_4	Lease # 4	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
14	Limited Period Patents, Franchises, Concessions or Licences	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -	T8
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	H8	$ 1,151,450							$ 1,151,450	$ -	$ -		$ -	$ -	7%			$ 80,602		$ 1,070,849	T8
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	5%			$ -		$ -	T8
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -	T8
42	Fibre Optic Cable	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -	T8
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -	T8
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -	T8
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	H8	$ 14,328							$ 14,328	$ -	$ -		$ -	$ -	45%			$ 6,448		$ 7,880	T8
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -	T8
47	Distribution System (acq'd post Feb 22/05)	H8	$ 8,772,785	$ 859,188						$ 9,631,973	$ -	$ -	0.50	$ -	$ 429,594	8%			$ 736,190		$ 8,895,783	T8
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	H8	$ 1,383	$ 336,273						$ 337,656	$ -	$ -	0.50	$ -	$ 168,137	55%			$ 93,236		$ 244,420	T8
95	CWIP	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -	T8
	CCA Adjustment for Accelerated CCA - Bridge Year	H8	$ -							$ -	$ -	$ -		$ -	$ -				$ 265,492		-$ 265,492	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
		H8	$ -							$ -	$ -	$ -		$ -	$ -						$ -	T8
	TOTALS		$ 13,757,105	$ 1,255,967	$ -	$ -	$ -	$ -	$ -	$ 15,013,072	$ -	$ -		$ -	$ 627,984		$ -	$ -	$ 1,501,121	B1	$ 13,511,951	

Ontario Energy Board

Income Tax/PILs Workform for 2022 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	179,775		179,775				179,775	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	
		0		0				0		0	
		0		0				0		0	
Total		**179,775**	**0**	**179,775**	B1	**0**	**0**	**179,775**	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	179,775		179,775				179,775	T13	0	
Accrued Employee Future Benefits:	H13	0		0				0	T13	0	
- Medical and Life Insurance	H13	0		0				0	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	424,842		424,842				424,842	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	
		0		0				0		0	
		0		0				0		0	
Total		**604,617**	**0**	**604,617**	B1	**0**	**0**	**604,617**	B1	**0**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2022 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income						T1	-$ 11,527	**A**
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				
Ontario (Max 11.5%)	11.5%	8.6%	-$ 997	8.6%	**B**			
Federal (Max 15%)	15.0%	12.9%	-$ 1,491	12.9%	**C**			
Combined effective tax rate (Max 26.5%)							21.59%	**D = B + C**
Total Income Taxes							**-$ 2,488**	**E = A * D**
Investment Tax Credits								**F**
Miscellaneous Tax Credits								**G**
Total Tax Credits							**$ -**	**H = F + G**
Corporate PILs/Income Tax Provision for Test Year							**$ -**	**I = E - H** S. Summary
Corporate PILs/Income Tax Provision Gross Up [1]					78.41%	**J = 1-D**	**$ -**	**K = I/J-I**
Income Tax (grossed-up)							**$ -**	**L = K + I** S. Summary

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 2022 Filers

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	443,101
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		957,283
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		
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		
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		250
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	179,775
Reserves from financial statements- balance at end of year	126	T13	604,617
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		
	295		
	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			423,652
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			

Total Additions			**2,165,577**
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	1,371,875
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	179,775
Reserves from financial statements - balance at beginning of year	414	T13	604,617
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 Contributions in Aid	395		40,286
	395		
	395		
	395		
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			423,652
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
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	**2,620,205**
NET INCOME FOR TAX PURPOSES		calculated	**-11,527**
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	**-11,527**

T0

Ontario Energy Board

Income Tax/PILs Workform for 2022 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	0		0
Amount to be used in Test Year and Price Cap Years	T1	0		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	calculated	0		0
Loss Carry Forward Generated in Test Year (if any)	T1	11,527		11,527
Other Adjustments				0
Balance available for use in Future Years	calculated	11,527		11,527

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 2022 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)
1	Buildings, Distribution System (acq'd post 1987)	B8	$ 394,061	42,000		-414
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	B8	$ -			0
2	Distribution System (acq'd pre 1988)	B8	$ 2,714,684			0
3	Buildings (acq'd pre 1988)	B8	$ -			0
6	Certain Buildings; Fences	B8	$ -			0
8	General Office Equipment, Furniture, Fixtures	B8	$ 311,357	5,000		-7,312
10	Motor Vehicles, Fleet	B8	$ 138,409	5,000		-4,081
10.1	Certain Automobiles	B8	$ -			0
12	Computer Application Software (Non-Systems)	B8	$ -			0
13_1	Lease # 1	B8	$ -			0
13_2	Lease # 2	B8	$ -			0
13_3	Lease # 3	B8	$ -			0
13_4	Lease # 4	B8	$ -			0
14	Limited Period Patents, Franchises, Concessions or Licences	B8	$ -			0
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	B8	$ 1,070,849			0
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	B8	$ -			0
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	B8	$ -			0
42	Fibre Optic Cable	B8	$ -			0
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -			0
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -			0
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	B8	$ 7,880			0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -			0
47	Distribution System (acq'd post Feb 22/05)	B8	$ 8,895,783	1,783,689		-68,735
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	B8	$ 244,420	66,000		-184,950
95	CWIP	B8	$ -			0
	CCA Adjustment for Accelerated CCA - Bridge Year	B8	-$ 265,492			0
	CCA Adjustment for Accelerated CCA - Test Year	B8	$ -			0
		B8	$ -			0
		B8	$ -			0
		B8	$ -			0
		B8	$ -			0
		B8	$ -			0
		B8	$ -			0
	TOTALS		$ 13,511,951	$ 1,901,689	$ -	-$ 265,492

(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	(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)
			$ 435,648	$ -	$ -	0.50	$ -	$ 21,000	4%			$ 16,586		$ 419,062
			$ -	$ -	$ -	0.50	$ -	$ -	6%			$ -		$ -
			$ 2,714,684	$ -	$ -		$ -	$ -	6%			$ 162,881		$ 2,551,803
			$ -	$ -	$ -		$ -	$ -	5%			$ -		$ -
			$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -
			$ 309,045	$ -	$ -	0.50	$ -	$ 2,500	20%			$ 61,309		$ 247,736
			$ 139,328	$ -	$ -	0.50	$ -	$ 2,500	30%			$ 41,048		$ 98,280
			$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
			$ -	$ -	$ -	0.00	$ -	$ -	100%			$ -		$ -
			$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
			$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
			$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
			$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
			$ 1,070,849	$ -	$ -		$ -	$ -	7%			$ 74,959		$ 995,889
			$ -	$ -	$ -	0.50	$ -	$ -	5%			$ -		$ -
			$ -	$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -
			$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -
			$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -
			$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -
			$ 7,880	$ -	$ -		$ -	$ -	45%			$ 3,546		$ 4,334
			$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
			$ 10,610,737	$ -	$ -	0.50	$ -	$ 891,845	8%			$ 777,511		$ 9,833,225
			$ 125,470	$ -	$ -	0.50	$ -	$ 33,000	55%			$ 50,859		$ 74,612
			$ -	$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -
			-$ 265,492	$ -	$ -		$ -	$ -						$ -
			$ -	$ -	$ -		$ -	$ -				$ 183,175		-$ 183,175
			$ -	$ -	$ -		$ -	$ -						$ -
			$ -	$ -	$ -		$ -	$ -						$ -
			$ -	$ -	$ -		$ -	$ -						$ -
			$ -	$ -	$ -		$ -	$ -						$ -
			$ -	$ -	$ -		$ -	$ -						$ -
			$ -	$ -	$ -		$ -	$ -						$ -
$ -	**$ -**	**$ -**	**$ 15,148,149**	**$ -**	**$ -**		**$ -**	**$ 950,845**		**$ -**	**$ -**	**$ 1,371,875**	T1	**$ 14,041,765**

Ontario Energy Board

Income Tax/PILs Workform for 2022 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	179,775		179,775				179,775		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	
		0		0				0		0	
		0		0				0		0	
Total		**179,775**	**0**	**179,775**	T1	**0**	**0**	**179,775**	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	179,775		179,775				179,775		0	
Accrued Employee Future Benefits:	B13	0		0				0		0	
- Medical and Life Insurance	B13	0		0				0		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	424,842		424,842				424,842		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	
		0		0				0		0	
		0		0				0		0	
Total		**604,617**	**0**	**604,617**	T1	**0**	**0**	**604,617**	T1	**0**	**0**

Appendix D – Actuarial Evaluation

January 30, 2020

Jeffrey Roy, CPA, CA
Chief Financial Officer
Ottawa River Power Corporation
283 Pembroke St. West, P.O Box 1087
Pembroke ON K8A 6Y6

Dear Jeffrey:

Re: Ottawa River Power Corporation Actuarial Valuation Report as at December 31, 2019 Post-Retirement Life Insurance Benefits

The Ottawa River Power Corporation ("the Corporation") has retained the services of Mondelis Actuarial Services Corporation to perform an accounting valuation of post-retirement life insurance benefits ("the Plan") as at December 31, 2019. The previous full valuation was prepared effective December 31, 2016. The following results have been prepared in accordance with the International Accounting Standard 19 ("IAS 19").

This document contains the accounting results to be disclosed in the December 31, 2019 financial statements. Disclosure exhibits are in Appendix F.

The detailed calculations, a summary of membership data, plan provisions and assumptions are provided in this report.

SUMMARY OF RESULTS

The following tables summarize the results for fiscal year 2019.

There are no Plan assets since the Plan is not funded.

Periodic Benefits Expense:	Jan 1, 2018 to Dec 31, 2018	Jan 1, 2019 to Dec 31, 2019
Current Service Cost (EOY)	4,974	4,712
Interest Cost	6,338	6,013
Net Periodic Benefit Cost	11,312	10,725

Change in Net (Liability) or Asset:	Jan 1, 2018 to Dec 31, 2018	Jan 1, 2019 to Dec 31, 2019
Balance at Beginning	(203,984)	(192,400)
Current year benefit cost	(11,312)	(10,725)
Benefits paid by employer	22,896	24,211
Actuarial gains/(losses) passed through OCI	0	(198,786)
Net Balance Sheet Asset/(Liability) at Ending	(192,400)	(377,700)

Benefit Obligation	Dec 31, 2019
Active members	60,900
Retired members	316,800
Total	377,700

Benefit obligation at December 31, 2019 is based on a discount rate of 3.25% per year.

CERTIFICATION

I confirm the following:

- The Plan's benefits are defined benefits as per IAS 19.
- The valuation and extrapolations were performed in accordance with the standards of the Canadian Institute of Actuaries. The financial statement items resulting from this valuation and extrapolations were determined in accordance with my understanding of IAS 19.
- The results herein were prepared using the Corporation's best-estimate assumptions as at December 31, 2019 and we express no opinion on them.
- I am not aware of any events subsequent to December 31, 2019 which, in my opinion, would have a material impact on the results of the valuations and extrapolations.
- I am a member in good standing of the Canadian Institute of Actuaries. I understand that this report will be used for audit evidence and may be relied on under the terms of the Joint Policy Statement approved by the Actuarial Standards Board (Canada) and the Auditing and Assurance Standards Board (Canada) as described in Section 1520 of the Canadian Institute of Actuaries Standards of Practice.
- I am, and Mondelis Actuarial Services Corporation is, independent with respect to the Corporation.
- The data upon which this extrapolation is based are sufficient and reliable for the purposes of the extrapolation.
- This report has been prepared, and my opinion given, in accordance with generally accepted actuarial practice.

Emerging experience differing from assumptions will result in gains and losses which will be revealed in future valuations. Please let me know if you require further information.

Sincerely,

Rick Johnston
Fellow, Society of Actuaries
Fellow, Canadian Institute of Actuaries
rick.johnston@mondelis.com
Direct: 226-336-8962

APPENDIX A – ACTUARIAL ASSUMPTIONS

Fiscal year ending	December 31, 2019	December 31, 2018
Economic Factors		
Discount rate for calculation of benefit expense	3.25%	3.25%
Discount rate for calculation of disclosures	3.25%	3.25%
Salary Increases	2.65%	2.00%
Demographic Factors		
Mortality	Canadian Pensioners' Mortality Table Public Sector (CPM2014Publ) projected on a generational basis using improvement scale CPM-B	Canadian Pensioners' Mortality Table Public Sector (CPM2014Publ) with adjustments
Termination of employment	Ontario Light Termination Rates, truncated at age 55	Age / Rate: <=20: 8.65% 25: 5.97% 30: 4.47% 35: 3.50% 40: 2.81% 45: 2.29% 50: 1.87% 60: 0.00% The rate grade linearly between the rate at the given ages
Retirement age	Greater of age 59 and current age	Age / Before EURA / From EURA: 55: 3.50% / 21.00% 56: 3.50% / 19.00% 57: 3.50% / 15.00% 58: 3.50% / 15.00% 59: 4.00% / 17.00% 60: 7.00% / 25.00% 61: 7.00% / 25.00% 62: 7.00% / 22.00% 63: 7.50% / 22.00% 64: 8.50% / 22.00% 65: 100.00% / 100.00%
Attribution period	Date of hire to retirement date	Date of hire to expected retirement date
Sales tax and expenses	10%	0%
Participation rate at retirement	100%	Same
Disability	None	Same

In the table above, all rates and percentages are annualized unless otherwise noted.

Discount Rate used under PSAB 3250/3255

The discount rate was determined as the single rate, rounded to the nearest 0.25%, that duplicates the Plan's obligations determined using the Fiera Capital/CIA yield curve as at December 31, 2019. The duration of the defined benefit obligation is 18.2 years.

Actuarial Methods

For all active members, the defined benefit obligation and future current service cost were calculated using the projected benefit method prorated on service. Under this method, the defined benefit obligation is equal to the actuarial present value of all future benefits taking into account the assumptions described above, multiplied by the ratio of service at the valuation date to projected service at the retirement date. The employer current service cost for a period is equal to the actuarial present value of all future benefits divided by the projected service at the retirement date.

For all retired members, the defined benefit obligation is equal to the actuarial present value of all future benefits taking into account the assumptions described above.

APPENDIX B - MEMBERSHIP DATA

We have based our valuation on membership data effective December 31, 2019 as provided by the Corporation. Age and service as at December 31, 2019 is summarized in the following tables:

Active Members

	Age	Sex	Service	2019 Salary	Date of Hire
1	32.6	M	9.6	83,190	31-May-2010
2	35.5	M	11.9	130,000	04-Feb-2008
3	28.2	F	3.2	50,305	06-Jan-2015
4	29.8	M	9.6	83,190	17-May-2010
5	40.7	M	17.9	83,190	18-Feb-2002
6	28.2	M	0.9	54,267	21-Jan-2019
7	27.5	M	5.6	83,190	18-Apr-2016
8	41.9	F	16.6	50,305	12-May-2003
9	28.4	M	4.6	83,190	20-May-2015
10	28.3	M	3.1	75,858	01-Jun-2016
11	57.8	F	19.4	85,000	21-Aug-2000
12	21.9	M	2.5	67,434	12-Jan-2017
13	55.7	M	18.3	83,190	24-Sep-2001
14	62.6	M	1.8	58,230	26-Mar-2018
15	46.7	M	22.1	93,174	12-Dec-1997
16	23.3	F	3.0	50,305	20-Jun-2016
17	57.7	F	21.6	50,305	01-Jun-1998
18	34.9	F	3.6	69,345	16-May-2016
19	28.6	M	2.3	89,181	28-Aug-2017
20	39.2	M	10.6	83,190	08-Jun-2009
21	27.3	F	1.3	50,305	31-Oct-2016
22	26.3	F	1.3	50,660	16-Apr-2018
23	61.3	F	23.7	50,305	25-Apr-1996
24	49.2	M	27.8	105,194	15-Aug-1994
25	27.8	M	7.0	83,190	02-Jan-2013

Summary of Active Member Data

Age	Values	Service 0-5	5-10	10-15	15-20	20-25	25-30	Grand Total
20-25	Count	2						2
	Average Age	22.64						22.64
	Average 2019 Salary	58,869						58,869
25-30	Count	7	3					10
	Average Age	27.91	28.39					28.05
	Average 2019 Salary	64,824	83,190					70,333
30-35	Count	1	1					2
	Average Age	34.95	32.64					33.79
	Average 2019 Salary	69,345	83,190					76,267
35-40	Count			2				2
	Average Age			37.38				37.38
	Average 2019 Salary			106,595				106,595
40-45	Count				2			2
	Average Age				41.34			41.34
	Average 2019 Salary				66,747			66,747
45-50	Count					1	1	2
	Average Age					46.72	49.21	47.96
	Average 2019 Salary					93,174	105,194	99,184
55-60	Count				2	1		3
	Average Age				56.74	57.72		57.07
	Average 2019 Salary				84,095	50,305		72,831
60-65	Count	1				1		2
	Average Age	62.57				61.29		61.93
	Average 2019 Salary	58,230				50,305		54,267
Total Count		**11**	**4**	**2**	**4**	**3**	**1**	**25**
Total Average Age		**30.74**	**29.45**	**37.38**	**49.04**	**55.24**	**49.21**	**37.67**
Total Average 2019 Salary		**63,553**	**83,190**	**106,595**	**75,421**	**64,594**	**105,194**	**73,827**

Retired Members

	Age	Sex	Date of Retirement	Current Amount of Insurance	Amount of Insurance at Retirement
1	59.7	M	30-Oct-2015	30,194	37,742
2	60.6	M	30-Jun-2014	36,653	48,870
3	64.2	M	01-Jan-2011	21,535	35,890
4	61.7	F	30-Apr-2019	62,872	62,872
5	80.5	M	31-Oct-1994	54,600	54,600
6	67.3	M	13-Sep-2013	2,000	2,000
7	62.4	M	31-Aug-2012	22,511	34,632
8	70.4	M	01-May-2010	38,699	38,698
9	63.9	M	30-Apr-2015	26,416	33,020
10	89.4	F	01-Jan-1995	35,700	35,700
11	64.8	M	30-May-2015	38,714	48,391
12	81.8	M	01-Nov-1994	69,300	69,300
13	57.8	F	20-Apr-2018	41,592	43,780
14	61.1	F	30-Apr-2015	22,387	27,983
15	68.6	M	20-May-2016	36,484	36,484
16	70.4	M	17-Aug-2014	15,288	20,384
17	62.4	M	30-Jun-2015	29,354	36,691
18	63.2	M	01-Dec-2011	33,624	33,624
19	60.7	F	30-Nov-2015	18,258	22,823

Summary of Retired Member Data

Age	Count	Average Age	Average Current Amount of Insurance
55-60	2	58.74	35,893
60-65	10	62.51	31,232
65-70	2	67.95	19,242
70-75	2	70.40	26,994
80-85	2	81.16	61,950
85-90	1	89.36	35,700
Grand Total	**19**	**66.89**	**33,483**

APPENDIX C – SUMMARY OF PLAN PROVISIONS

The following summary is based on information provided by the Corporation and summarizes the amount of life insurance upon retirement.

Service Criteria	Amount of Post-Retirement Life Insurance
Less than 10 year of service	$2,000
10 or more years of service	50% of final annual earnings, reducing by 2.5% of final annual earnings each year to an ultimate benefit of 25% of final annual earnings

A number of retired members were insured under the prior life insurance plan before March 1, 1980 and are eligible for a different amount of post-retirement life insurance that does not decrease during retirement.

APPENDIX D – ACCOUNTING POLICIES

The Corporation uses a December 31 measurement date for valuing the post-retirement life insurance benefits.

APPENDIX E – GAINS AND LOSSES

A summary of the plan experience as at December 31, 2019 is as follows:

Demographic Assumptions	
Change in mortality assumption	6,066
Change in termination assumption	(2,357)
Change in retirement age assumption	(1,022)
	2,686
Financial Assumptions	
Change in salary increase assumption	(3,213)
Change in tax and expense assumption	(34,337)
	(37,550)
Other Experience	
Other experience	(163,922)
Total	(198,786)

APPENDIX F - ACCOUNTING DISCLOSURE EXHIBITS

Period Beginning	**2018-01-01**	**2019-01-01**
Period Ending	**2018-12-31**	**2019-12-31**
Weighted-average Assumptions		
Period Beginning Discount Rate	3.25%	3.25%
Period Ending Discount Rate	3.25%	3.25%
Periodic Benefits Expense for the 12-Month Period		
Current Service Cost (EOY)	4,974	4,712
Administrative Expenses	0	0
Interest Cost	6,338	6,013
Net Periodic Benefit cost	11,312	10,725
Remeasurement effects recognized in OCI		
Actuarial (gain)/loss - experience	0	163,922
Actuarial (gain)/loss - demographic assumptions	0	(2,686)
Actuarial (gain)/loss - financial assumptions	0	37,550
Gain/(loss) on asset ceiling	0	0
Remeasurement effects recognized in OCI	0	198,786
Total Cost Recognized in Comprehensive Income	**11,312**	**209,511**
Benefit Obligation		
Balance at Beginning	203,984	192,400
Current Service Cost	4,974	4,712
Net Interest cost on benefit obligation	6,338	6,013
Actuarial (gain)/loss - experience		163,922
Actuarial (gain)/loss - demographic assumptions		(2,686)
Actuarial (gain)/loss - financial assumptions		37,550
Gross benefits paid	(22,896)	(24,211)
Past service cost	0	0
Balance at End	192,400	377,700
Funded status, end of period:		
Fair value of plan assets	0	0
Benefit obligation	192,400	377,700
Funded status	(192,400)	(377,700)

Period Beginning	**2018-01-01**	**2019-01-01**
Period Ending	**2018-12-31**	**2019-12-31**
Change in Net (Liability) or Asset:		
Balance at Beginning	(203,984)	(192,400)
Current year benefit cost	(11,312)	(10,725)
Benefits paid by employer	22,896	24,211
Change in liability due to recognition of Asset Ceiling	0	0
Actuarial gains/(losses) passed through OCI	0	(198,786)
Net Balance Sheet Asset/(Liability) at Ending	(192,400)	(377,700)

Sensitivity Testing (Change in Obligation)	
Change with 1.0% lower discount rate	78,600
Change with 1.0% higher discount rate	(59,100)
Change with 1 year greater life expectancy	(12,600)
Change with 1 year reduction in retirement age assumption	(900)