Hydro One Networks Inc.
483 Bay Street
7th Floor South Tower
Toronto, Ontario M5G 2P5
HydroOne.com

Frank D'Andrea
Vice President, Reliability Standards
and Chief Regulatory Officer
T 416.345.5680
C 416.568.5534
frank.dandrea@HydroOne.com

BY EMAIL AND RESS

August 31, 2022

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2022-0041 – Hydro One Remote Communities Inc. – 2023 Revenue Requirement and Rates Application – Application and Evidence

Attached please find Hydro One Remote Communities Inc.'s (Remotes) application for the approval of the 2023 revenue requirement and customer rates, for the distribution and generation of electricity, to be implemented on May 1st, 2023.

A request for confidential treatment of certain information will be submitted separately.

The Application has been submitted electronically using the OEB's Regulatory Electronic Submission System.

Please contact me if you have any questions.

Sincerely,

Frank D'Andrea

Frank D'Andrea

EXHIBIT LIST & TABLE OF CONTENTS

This page has been left blank intentionally.

EXECUTIVE SUMMARY OF APPLICATION

INTRODUCTION

Hydro One Remote Communities Inc. (Remotes), a subsidiary of Hydro One Inc. (Hydro One), is an integrated generation and distribution company licensed to generate and distribute electricity within 21 isolated communities and one grid-connected community in northern Ontario (ED-2003-0037 and EG-2003-0138). Consistent with the Board's Decision in RP-1998-0001, Remotes is 100% debt-financed and is operated as a break-even company with no return on equity.

Remotes is driven by its corporate vision, mission, and business values. Together, they provide the basis to deliver on targeted performance objectives.

Corporate Vision

> *"We will be the leading electrical utility and a trusted partner to remote communities in Ontario's north."*

Corporate Mission

> *"We supply safe, reliable and affordable electricity to remote communities by focusing on continuous improvement, operational excellence and outstanding customer service."*

Strategic Goals

Consistent with Hydro One's overall goals and with our vision and mission, Remotes' current business plan is designed to meet the following objectives:

- Create an injury-free workplace and protect the safety of the public
- Supply safe, reliable, and affordable electricity to customers
- Offer an exceptional customer experience

- Build strong, respectful relationships with community leaders
- Improve the safety, reliability and efficiency of distribution and generation systems
- Build a culture of actively engaged employees, with the skills and ability to respond to our customers' needs
- Protect and sustain the environment for future generations

1.0 APPLICATION SUMMARY

Remotes is making this application in accordance with the requirements of the Ontario Energy Board *Filing Requirements for Electricity Distribution Rate Applications – 2022 Edition for 2023 Rate Applications* April 18, 2022 (Filing Requirements). The proposed revenue requirement and rates included in this Application have been prepared on the basis of a Price Cap Incentive Rate-setting method (Price Cap IR) and include a 3.72% overall rate increase.[1] The historical period of the application covers the 2018-2021 period, the bridge year is 2022, the test year is 2023, and the forecast and Distribution System Plan (DSP) period is 2023-2027. Comparisons made throughout the Application are relative to the values approved in EB-2017-0051 with 2018 as the last OEB-Approved year. The Remotes Business Plan which underpins this application is filed as Exhibit A, Tab 3, Schedule 1, Attachment 1.

Consistent with the Board's Decision in EB-2011-0427, Remotes uses US GAAP as its accounting standard.

WATAYNIKANEYAP TRANSMISSION PROJECT

The Wataynikaneyap (Watay) Transmission Project is a partnership between Wataynikaneyap Power and 24 First Nations Communities. The transmission project seeks to construct and operate a 1,700 km transmission line in Northwestern Ontario to allow for the supply of clean, reliable energy to thousands of residents in remote First Nations communities in the region.

[1] Based on the average distribution and total bill increase for Ontario LDCs and the Ontario Energy Board's RRRP Analysis as of May 1, 2022.

Watay seeks to connect 16 communities to the provincial electricity grid by 2024, of which 10 are already serviced by Hydro One Remotes. The remaining 6 communities will function as Independent Power Authority (IPA) communities and will also be serviced by Hydro One Remotes.[2] The connection of these communities will result in several changes to Remotes' operations and management.

First, Remotes will transition to a transmission-connected distributor while continuing to provide off-grid electricity generation and distribution, both as primary or prime power and as backup power. This transition will change the operating, maintenance, and replacement practices as well as the general utilization of the existing generation assets. The connection of these communities is also expected to reduce the overall fuel requirements and costs for Remotes. However, these reductions are expected to be offset by increases in a new cost category for Remotes, cost of power, which is forecasted at $8.2M annually starting in 2023. There will also be additional OM&A increases resulting directly from the Watay project, which are forecasted at $66M annually starting in 2023, however these will be a flow-through for Remotes and will be funded through the Remote or Rural Rate Protection (RRRP) plan.

The connection of these communities will also increase Remotes' customer count by approximately 974 customers by 2027. To support this increase and allow for the integration of these additional customers, two key investments will be required to support the Watay project. Remotes will require a System Access investment for wholesale net metering, forecasted at $7.5M (see Exhibit B, Tab 2, Schedule 1, Appendix A) and the Remotes Beaverhall operating facility will require a $2.4M General Plant investment for expansion (see Exhibit B, Tab 2, Schedule 1, Appendix A).

---

[2] Pikangikum First Nation was connected to the Ontario power grid on December 20, 2018, becoming the first community to connect via the Watay Transmission Project.

Customer rate classes under the Standard A rates will be retained throughout the plan period (2023-2027) of this Application, however lower Standard A rates will apply as each community is connected to the provincial grid.

General matters regarding the Watay project such as scope, magnitude, timing, investments, or otherwise are outside of the scope of this Application.[3]

1.1 REVENUE REQUIREMENT

Remotes is seeking approval of a total service revenue requirement of $134,547k for the 2023 test year. Remotes seeks to recover this amount directly through rates from its customers ($24,815k), through other revenues ($915k)[4], and through the RRRP fund ($108,817k). The RRRP is broken down as follows: $42,817k is the RRRP-Operating and $66,000k is the RRRP-Watay, with RRRP-Watay being new to the Remotes application. External revenues are discussed at Exhibit F, Tab 3, Schedule 1. External and other Revenues consist of external work, late payment and miscellaneous revenues. Calculation of the revenue requirement appears in the evidence at Exhibit F, Tab 1, Schedule 1. Tables 1 and 2 below provide a schedule of the main drivers of revenue requirement changes from the last OEB-approved year.

Table 1 - Breakdown of Revenue Requirement (*in thousands $, u.o.s.*)

	2018 OEB-Approved	2023 Test Year	Var.$	Var.%
Total Revenue Requirement	**$53,834**	**$134,547**	**$80,713**	**150%**
Recovered through RRRP	$35,223	$108,817	$73,594	209%
Recovered through Other Revenues	$999	$915	($84)	-8%
Total Rates Revenue Requirement	**$17,612**	**$24,815**	**$7,203**	**41%**

[1] *u.o.s – unless otherwise specified*

[3] The EB-2022-0149 proceeding is the appropriate forum for further enquiries on the Watay project.
[4] Remotes receives less than 4% of its revenues from external sources ($915k) in 2023.

Table 2 - Breakdown of RRRP (*in thousands $, u.o.s.*)

		2018 OEB-Approved	2023 Test Year	Var.$	Var.%
	OM&A				
A	Programs and Administration	$21,343	$22,041	$698	3%
B	Fuel	$25,900	$30,365	$4,465	17%
C	Cost of Power[1]	-	$8,162	$8,162	
D	Watay Transmission Connection Cost	-	$66,000	$66,000	
E=A+B+C+D	**Total OM&A, including Watay**	**$47,243**	**$126,568**	**$79,325**	**168%**
F=E-D	**Total OM&A, excluding Watay[2]**	**$47,243**	**$60,568**	**$13,325**	**28%**
G	Depreciation	$3,576	$3,571	($5)	0%
H	Amortization	$1,032	$1,883	$851	82%
I	Financing Charges	$2,052	$2,525	$473	23%
J	Income Tax Recovery	($69)	-	$69	-100%
K=E+G+H+I+J	**Total Service Revenue Requirement, including Watay**	**$53,834**	**$134,547**	**$80,713**	**150%**
L=K-D	**Total Revenue Requirement, excluding Watay[2]**	**$53,834**	**$68,547**	**$14,713**	**27%**
M	Energy Sales	$17,612	$24,815	$7,203	41%
N	Late Payment Charges	$318	$338	$20	6%
O	Other Distribution Revenues	$681	$577	($104)	-15%
P	**Total Customer Revenues**	**$18,611**	**$25,730**	**$7,119**	**38%**
Q=L-P	**Remotes Annual RRRP-Operating Subsidy**	**$35,223**	**$42,817**	**$7,594**	22%
D	**Remotes Annual RRRP-Watay Subsidy[2]**	**-**	**$66,000**	**$66,000**	
S=Q+D	**Total RRRP Subsidy**	**$35,223**	**$108,817**	**$73,594**	**209%**

[1] The cost of power resulting from the connection of communities via the Wataу project to the provincial electricity grid.
[2] Watay costs/subsidies not applicable during the prior application.

The increase in the total revenue requirement relative to the prior application is primarily due to the Watay transmission connection cost, the cost of power resulting from connection to the provincial electricity grid, and fuel costs used for diesel generation of electricity.

1.2 LOAD FORECAST SUMMARY

The load forecast for the 2023 test year is 97,425 MWhs with a customer count of 5,191.[5] Remotes has two broad categories of customers, Standard A or government customers whose rates have historically been set above cost, and those Residential and General Service customers who benefit from Rural and Remote Rate Protection. These two categories are set out in O. Reg. 442/01, the regulation under the *Ontario Energy Board Act, 1998,* that establishes the rules for RRRP. Most of Remotes' customers pay rates that are subsidized by RRRP and are set well below the per kWh cost to serve them from diesel fuel.

The calculation of the load forecast appears in the evidence at Exhibit C, Tab 1, Schedule 1. Table 3 shows the load forecast and customer summary, and the change from the prior application.

Table 3 - Load Forecast and Customer Count Summary

	2018 OEB-Approved	2023 Test Year	Var.	Var.%
Load (MWhs)	**62,565**	**97,425**	**34,860**	**56%**
Customer Count[6]				
Remotes	3,652	4,519	867	24%
Cat Lake	0	260	260	
Watay	0	412	412	
Total Customer Count	**3,652**	**5,191**	**1,539**	**42%**

1.3 RATE BASE AND DISTRIBUTION SYSTEM PLAN (DSP)

Remotes' requested rate base and forecasted capital expenditures, net of contributed capital, for the 2023 test year are $56,219k and $10,591k respectively. In accordance with the Filing Requirements, the rate base underlying the test year revenue requirement includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net

[5] Remotes 2023 customer count is based on 4,519 Remotes customers, 412 Watay customers (182 Muskrat Dam, 199 Wunnumin Lake, 31 Wawakapewin), and 260 Cat Lake customers.
[6] Customer numbers are year-end.

fixed assets are gross plant in service minus accumulated depreciation and contributed capital.[7] Working capital is calculated using the formula as described in Section 5.4 of 2006 Electricity Distribution Rate Handbook.

Major drivers of the capital expenditures in the DSP include: Watay investments, customer service requests, asset failure replacements, assets at the end of their service life due to failure risk, system capacity investments, system reliability and operational efficiency and non-system physical plant, which are discussed in DSP section 5.2.1.5.

Calculation of the rate base appears in the evidence at Exhibit B, Tab 1, Schedule 1. Table 4 shows the rate base and capital expenditures and the change from the request made in the prior application.

Table 4 - Rate Base and Net Capital Expenditures (*in thousands $, u.o.s.*)

	2018 OEB-Approved	2023 Test Year	Var.$	Var.%
Rate Base	$45,302	$56,219	$10,917	24%
Capital Expenditures (Net)	$2,910	$10,591	$7,681	264%

1.4 OPERATIONS, MAINTENANCE AND ADMINISTRATION (OM&A)

Remotes' forecast OM&A expenditures for the 2023 test year are $126,568k, and includes $66,000k for the Watay transmission connection cost, $30,365k for diesel fuel for the generation of electricity, $22,041k for general program administration, and $8,162k for cost of power arising from the connection to the provincial electricity grid. The overall proposed OM&A expenditures are driven by the need to meet customer, regulatory and statutory requirements regarding service and reliability as well as to repair, maintain and replace aging assets. These expenditures are summarized at Exhibit D, Tab 1, Schedule 1 and discussed in Exhibit D Schedules.

[7] Contributed capital refers to amounts contributed by third parties to specific capital projects, e.g. Joint Use Assets, Customer Contributions

The primary drivers of OM&A expenditures in the 2023 test year are the Watay transmission connection cost, cost of power, and fuel costs. Program and administration OM&A are forecasted to be slightly higher by $698k or 3% relative to the prior application. Remotes plans and organizes its OM&A expenses based on the various work programs and functions performed by the company. Exhibits in support of OM&A costs, along with variance discussions, have been prepared by program area, and appear within the submitted evidence as shown in Table 6.

Table 5 - Breakdown of OM&A Expenditures (*in thousands $, u.o.s.*)

		2018 OEB-Approved	2023 Test Year	Var.$	Var.%
	OM&A				
A	Programs and Administration	$21,343	$22,041	$698	3%
B	Fuel	$25,900	$30,365	$4,465	17%
C	Cost of Power[1]	$0	$8,162	$8,162	
D	Watay Transmission Connection Cost	$0	$66,000	$66,000	
E=A+B+C+D	**Total OM&A, including Watay**	**$47,243**	**$126,568**	**$79,325**	**168%**
F=E-D	**Total OM&A, excluding Watay**	**$47,243**	**$60,568**	**$13,325**	**28%**

[1] The cost of power resulting from the connection of communities via the Watay project to the provincial electricity grid.

Table 6 - OM&A Cost Categories and Evidence Reference

Program Areas	Reference
Summary of OM&A Expenses	**Exhibit D, Tab 1, Sch 1**
Generation	Exhibit D, Tab 1, Sch 2
Fuel	Exhibit D, Tab 1, Sch 3
Distribution	Exhibit D, Tab 1, Sch 4
Customer Care	Exhibit D, Tab 1, Sch 5
Community Relations	Exhibit D, Tab 1, Sch 6
Other Power Supply Expenses	Exhibit D, Tab 1, Sch 7
Shared Services and Other Administrative Costs	Exhibit D, Tab 1, Sch 8
Cost of External Work	Exhibit D, Tab 2, Sch 1

1.5 COST OF CAPITAL

Consistent with the Board's Decision in RP-1998-0001 and subsequent Decisions, Remotes is 100% debt-financed and is operated as a break-even company. Remotes is not seeking a return on equity. As such, Remotes' cost of capital is based on 100% debt, consisting of 4% deemed short term debt and 96% long term debt.

Long term debt includes $43,000k of long-term debt issued to Hydro One Inc., reflecting debt issued by Hydro One Inc. to third party public debt investors, and $10,969k of deemed long term debt.

For Remotes, the deemed short-term rate is 1.17%, consistent with the Deemed Short-Term Debt Rate in the OEB's Cost of Capital Parameter Updates for 2022 Cost of Service Applications for Rates effective January 1, 2022, dated October 28, 2021. Remotes assumes that the deemed short-term debt rate for 2023 will be updated as part of the final Decision and Order issued by the OEB in this Application. There are no deviations from the OEB's cost of capital methodology.

Table 7 provides a summary of the proposed capital structure and cost of capital parameters, resulting in the Weighted Average Cost of Capital (WACC) of 4.49% for the 2023 test year.

Remotes' evidence in support of its cost of capital appears at Exhibit E, Tab 1, Schedule 1.

Table 7 - 2023 Cost of Capital Structure and WACC *(in thousands $, u.o.s)*

Particulars	**$**	**% Of Rate Base**	**Cost Rate (%)**	**Weighted Cost Rate %**	**Cost of Capital**
Deemed short-term debt	$ 2,249	4.0%	1.17%	0.05%	$26
Third Party long-term debt	$43,000	76.5%	4.63%	3.54%	$1,991
Deemed long-term debt	$10,969	19.5%	4.63%	0.90%	$508
Total	**$56,218**	**100%**		**4.49%**	**$2,525**

1.6 COST ALLOCATION AND RATE DESIGN

As part of this Application, Remotes is not proposing any new customer classes or class definition changes and there are no changes to the way in which Remotes charges its customers (service charges, if applicable, and volumetric charges, are detailed in Exhibit F, Tab 2, Schedule 1).[8] As discussed in Section 1.8, bill impacts for all customers are below 10% therefore no bill impact mitigation plan is required.

1.7 DEFERRAL AND VARIANCE ACCOUNTS

In accordance with standard regulatory practice, Remotes has incurred prior costs for which it is requesting approval to clear its accounts as part of this Application. The December 2021 audited Rural and Remote Rate Protection (RRRP) variance account balance is $9,732k. The balance is primarily due to increased diesel fuel costs and the connection of Pikangikum First Nation to the Ontario power grid on December 20, 2018 as part of the Watay Transmission Project, which resulted in power purchases. Remotes is proposing to recover this RRRP Variance Account balance in equal amounts of $1,946k annually over the 2023 to 2027 period, with a one-time disposition in 2023 to clear the residual credit balance of $10k in the Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation, resulting in a total RRRP amount of $110,753k in the 2023 test year, as described in Table 2 of Exhibit G, Tab 1, Schedule 1.

Remotes is not requesting any new deferral and/or variance accounts as part of this Application. However, Remotes is seeking to continue the RRRP Variance Account to ensure that the business maintains its break-even model. Remotes' evidence regarding these account balances and proposed disposition appears at Exhibit H, Tab 1, Schedule 1.

[8] Remotes further notes that revenue-to-cost ratios do not apply given the manner in which Remotes' rates are set pursuant to O. Reg. 442/01.

1.8 CUSTOMER BILL IMPACTS

Remotes is seeking approval for a 3.72% increase in customer rates for all its customer rate classes at all levels of consumption.[9] Tables 8 to 17 provide a summary of the bill impacts, and highlighted common consumption levels, including proposed bill impacts for alternative consumption profiles and customer groups.

Details on the proposed rate increase can be found in Exhibit G, Tab 2, Schedule 1. Calculation of the rate revenue requirement appears in the evidence at Exhibit G, Tab 4, Schedule 1.

Table 8 - Bill Impacts for Residential (R2) Customers

RESIDENTIAL YEAR ROUND (R2)							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
100	$31.82	$27.73	$33.01	$28.77	1.19	1.04	3.74%
250	$47.09	$41.04	$48.85	$42.57	1.76	1.53	3.74%
500	$72.54	$63.22	$75.25	$65.58	2.71	2.36	3.74%
750	**$97.99**	**$85.40**	**$101.65**	**$88.59**	**3.66**	**3.19**	**3.74%**
1000	$123.44	$107.58	$128.05	$111.60	4.61	4.02	3.73%
2000	$259.24	$225.93	$268.95	$234.39	9.71	8.46	3.75%
2500	$327.14	$285.10	$339.40	$295.79	12.26	10.68	3.75%

[9] Based on the average distribution and total bill increase for Ontario LDCs and the Ontario Energy Board's RRRP Analysis as of May 1, 2022.

Table 9 - Bill Impacts for Residential Seasonal (R4) Customers

RESIDENTIAL SEASONAL (R4)							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
100	$46.75	$40.74	$48.49	$42.26	1.74	1.52	3.72%
250	$62.02	$54.05	$64.33	$56.06	2.31	2.01	3.72%
500	$87.47	$76.23	$90.73	$79.07	3.26	2.84	3.73%
750	$112.92	$98.41	$117.13	$102.08	4.21	3.67	3.73%
1000	$138.37	$120.59	$143.53	$125.09	5.16	4.50	3.73%
2000	**$274.17**	**$238.94**	**$284.43**	**$247.88**	**10.26**	**8.94**	**3.74%**

Table 10 - Bill Impacts for General Service Single Phase (G1)

GENERAL SERVICE SINGLE PHASE (G1)							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
1000	$150.89	$131.50	$156.46	$136.35	5.57	4.85	3.69%
2000	$264.99	$230.94	$274.76	$239.45	9.77	8.51	3.69%
3000	$379.09	$330.38	$393.06	$342.55	13.97	12.17	3.69%
5000	$607.29	$529.25	$629.66	$548.75	22.37	19.50	3.68%

Table 11 - Bill Impacts for General Service (G3)

GENERAL SERVICE THREE PHASE (G3)							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
2000	$274.26	$239.02	$284.37	$247.83	10.11	8.81	3.69%
3000	$388.36	$338.46	$402.67	$350.93	14.31	12.47	3.68%
5000	$616.56	537.33	$639.27	$557.12	22.71	19.79	3.68%
10,000	$1,187.06	$1,034.52	$1,230.77	$1,072.62	43.71	38.09	3.68%

Table 12 - Rate Impacts for Streetlights

STREET LIGHTING							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
500	$56.60	$49.33	$58.70	$51.16	2.10	1.83	3.71%
2000	$226.40	$197.31	$234.80	$204.63	8.40	7.32	3.71%
4000	$452.80	$394.62	$469.60	$409.26	16.80	14.64	3.71%

Table 13 - Bill Impacts for Standard A Residential Road/Rail

STANDARD A RESIDENTIAL ROAD/RAIL							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
100	$67.04	$58.43	$69.53	$60.60	2.49	2.17	3.71%
250	$167.60	$146.06	$173.83	$151.49	6.23	5.43	3.71%
500	$359.10	$312.96	$372.45	$324.59	13.35	11.63	3.72%
750	$550.60	$479.85	$571.08	$497.69	20.48	17.84	3.72%
1000	$742.10	$646.74	$769.70	$670.79	27.60	24.05	3.72%
2000	$1,508.10	$1,314.31	$1,564.20	$1,363.20	56.10	48.89	3.72%

Table 14 - Bill Impacts for Standard A Residential Air Access

STANDARD A RESIDENTIAL AIR ACCESS							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
250	$253.03	$220.51	$262.45	$228.73	9.42	8.21	3.72%
500	$529.95	$461.85	$549.68	$479.04	19.73	17.19	3.72%
750	$806.88	$703.19	$836.90	$729.36	30.03	26.17	3.72%
1000	$1,083.80	$944.53	$1,124.13	$979.67	40.33	35.14	3.72%
2000	$2,191.50	$1,909.89	$2,273.03	$1,980.94	81.53	71.05	3.72%

Table 15 - Rate Impacts for Standard A General Service Road/Rail

STANDARD A GENERAL SERVICE ROAD RAIL							
Scenario (kWh)	Current Bill	Current Bill with HST (includes rebate)	Proposed Bill	Proposed Bill with HST (includes rebate)	$ Change	$ Change with HST (includes rebate)	Percentage Change
1000	$766.00	$667.57	$794.50	$692.41	28.50	24.84	3.72%
2000	$1,532.00	$1,335.14	$1,589.00	$1,384.81	57.00	49.68	3.72%
5000	$3,830.00	$3,337.85	$3,972.50	$3,462.30	142.50	124.19	3.72%

Table 16 - Rate Impacts for Standard A General Service Air Access

STANDARD A GENERAL SERVICE AIR ACCESS							
Scenario (kWh)	Current Bill	Current Bill with HST (includes rebate)	Proposed Bill	Proposed Bill with HST (includes rebate)	$ Change	$ Change with HST (includes rebate)	Percentage Change
1000	$1,107.70	$965.36	$1,148.90	$1,001.27	41.20	35.91	3.72%
2000	$2,215.40	$1,930.72	$2,297.80	$2,002.53	82.40	71.81	3.72%
5000	$5,538.50	$4,826.80	$5,744.50	$5,006.33	206.00	179.53	3.72%

Table 17 - Rate Impacts for Standard A Grid Connected

STANDARD A GRID CONNECTED							
Scenario (kWh)	Current Bill	Current Bill with HST (includes rebate)	Proposed Bill	Proposed Bill with HST (includes rebate)	$ Change	$ Change with HST (includes rebate)	Percentage Change
1000	$347.00	$302.41	$359.90	$313.65	12.90	11.24	3.72%
2000	$694.00	$604.82	$719.80	$627.31	25.80	22.48	3.72%
5000	$1,735.00	$1,512.05	$1,799.50	$1,568.26	64.50	56.21	3.72%

1.9 OTHER REQUESTS IN THIS APPLICATION

As part of this Application, Remotes is requesting the elimination of two service charges, the Arrears Certificate and Meter Dispute Fee. Details on this proposed request can be found in Exhibit F, Tab 3, Schedule 1.

Remotes is also seeking exemption of Account 1588 and is requesting that the current exemptions noted in Exhibit A, Tab 2, Schedule 1 be maintained.

Remotes is also requesting that the RRRP (Remotes Operating) amount approved by the OEB for 2023 be adjusted each year by the OEB's approved escalation. This would lower amounts to be recovered at each rebasing in the RRRP Variance Account. Details of this proposal can be found in Exhibit G, Tab 1, Schedule 1.

This page has been left blank intentionally.

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 (Sched. B) (the Act);

AND IN THE MATTER OF an Application by Hydro One Remote Communities Inc. for an Order or Orders approving rates for the distribution of electricity.

APPLICATION

THE APPLICANT AND ORDERS REQUESTED

1. The Applicant is Hydro One Remote Communities Inc., a subsidiary of Hydro One Inc. (Hydro One). The Applicant, which will hereinafter be referred to as "Remotes", is an Ontario corporation with its head office in Toronto and its main operations in Thunder Bay. The Applicant is an integrated generation and distribution company licensed to provide electricity within 21 isolated communities and one grid-connected community in northern Ontario (ED-2003-0037 and EG-2003-0138). A description of the corporate and organizational structure can be found in Exhibit A, Tab 6, Schedule 1.

2. Remotes hereby applies to the Ontario Energy Board (OEB or the Board), pursuant to section 78 of the *Ontario Energy Board Act, 1998*, for an Order or Orders approving its proposed 2023 revenue requirement and customer rates for the distribution and generation of electricity, effective May 1, 2023.

3. Remotes is a unique integrated generator and distributor in Ontario and is exempt from a number of the legal and regulatory requirements imposed on most distributors. Remotes generates electricity at diesel generating stations in certain isolated communities in the far north and distributes the electricity to customers in each community. As such, Remotes is

neither an embedded distributor nor a host distributor. For more details on the compliance with the filing requirements, see Exhibit A, Tab 2, Schedule 1.

SPECIFIC APPROVALS REQUESTED

4. Remotes hereby applies to the OEB for orders approving:

    i. total service revenue requirement of $134,547k for the Test Year 2023, of which $24,815k is proposed to be recovered through customer rates and $915k from other revenues, leaving $108,817k to be recovered from Rural and Remote Rate Protection (RRRP), as described in Exhibit G, Tab 1, Schedule 1. The RRRP is further categorized as follows: $42,817k directly related to Remotes RRRP-Operating; and $66,000k directly related to the RRRP-Watay Transmission Project;

    ii. Electricity distribution rates as identified in the proposed Tariff of Rates and Charges in Exhibit G, Tab 4, Schedule 1 to be effective May 1, 2023, which are calculated to support Remotes' 2023 rates revenue requirement of $24,815k as further outlined in Attachment 1 of Exhibit G, Tab 1, Schedule 1.

    iii. disposition of the December 31, 2021 audited balance in the RRRP Variance Account of $9,732k to be smoothed over the 2023 to 2027 period, along with a one-time disposition in 2023 to clear the residual credit balance of $10k in the Rate Rider for Recovery of COVID-19 Forgone Revenue, as described in Exhibit H, Tab 1, Schedule 1. This would result in a total recovery of $110,753k in RRRP to be established in the 2023 test year as described in Table 2 of Exhibit G, Tab 1, Schedule 1;

    iv. continuation of the RRRP Variance Account as described in Exhibit H, Tab 1, Schedule 1;

    v. proposed escalation for the RRRP (Operating) account, as described in Exhibit G, Tab 1, Schedule 1;

vi. continuation of RRRP funding for Watay related flow-through costs as per EB-2018-0190 and all subsequent revisions;[1]

vii. a 3.72% increase to customer rates as identified in the proposed Tariff of Rates and Charges in Exhibit F, Tab 2, Schedule 1, to be effective May 1, 2023;

viii. removal of two specific service charges: the Arrears certificate and the Meter Dispute Test as detailed in Exhibit G, Tab 3, Schedule 1. Remotes seeks approval to continue to charge customers all other specific service charges identified in the proposed Tariff of Rates and Charges in Exhibit G, Tab 4, Schedule 1, to be effective May 1, 2023; and

ix. exemption from the use of Account 1588, as described in Exhibit A, Tab 2, Schedule 1, section 3.0.

CUSTOMERS AFFECTED & DIRECTIONS FROM PREVIOUS PROCEEDINGS

5. The persons affected by this Application are the ratepayers of Remotes and of RRRP. It is impractical to set out their names and addresses because they are too numerous. There are no discrete customer groups that are affected by changes to other rates and charges.

6. Remotes did not have any specific directions from the OEB or the 2018 settlement agreement in the prior proceeding (EB-2017-0051) required to be included in this Application.

PROPOSED EFFECTIVE DATE

7. Remotes requests that the OEB's rate orders be effective May 1, 2023.

[1] Per EB-2018-0190, Decision and Order, April 30, 2019, it was noted that: "O. Reg. 442/01 (Rural or Remote Electricity Rate Protection) was amended effective July 1, 2016 to allow RRRP to be used to cover a portion of the costs required to build and operate the lines that would connect remote First Nations communities to the transmission grid" (p. 9).

8. In the event the requested rate orders cannot be made effective by such date, Remotes requests an Interim Order making its current distribution rates and charges effective on an interim basis as of May 1, 2023. Remotes requests the ability to recover any differences between the interim rates and the final rates effective May 1, 2023, based on the OEB's final Decision and Order herein.

NOTICE AND FORM OF HEARING REQUESTED

9. To reach the largest number of customers in its service territory, Remotes requests that notice of this Application be published on the Wawatay website in English, Cree, Oji Cree and Ojibway, the Thunder Bay Chronicle Journal and the Sudbury Star.

10. Remotes requests that this Application be heard by way of a written hearing.

11. A copy of this application and related documents can be found on Remotes' website listed below. Remotes does not use social media accounts such as Twitter or Facebook to communicate with its customers. However, Remotes communicates with its customers through email notices as well as through an e-blast/bulletin.
https://www.hydrooneremotes.ca/regulatory

12. The written evidence filed with the Board may be amended from time to time prior to the Board's final decision on the Application. Further, the Applicant may seek meetings with Board staff and intervenors in an attempt to identify and reach agreements to settle issues arising out of this Application.

CONDITIONS OF SERVICE

13. There are no rates and charges linked in the Conditions of Service that are not in Remotes' Tariff of Rates and Charges. The current Conditions of Service can be found on Remotes' website at:
https://www.hydrooneremotes.ca/regulatory

CONFIDENTIAL FILINGS CONTAINED IN APPLICATION

14. Hydro One has not filed any personal information within this Application pursuant to Rule 9A of the *OEB Rules of Practice and Procedure.* A certification regarding personal information has been filed at Exhibit A, Tab 1, Schedule 3, Attachment 2.

15. Hydro One has filed this evidence in accordance with the Practice Direction on Confidential Filings. Redacted versions of the income tax return filed at Exhibit D, Tab 5, Schedule 2 have been included in this application. Non-redacted versions will be filed separately with the OEB.

CONTACT INFORMATION

16. Remotes requests that a copy of all documents filed with the Board by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

a) **The Applicant:**

Carla Molina
Sr. Regulatory Coordinator
Hydro One Networks Inc.

Address for personal service:	7th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Mailing Address:	7th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Telephone:	(416) 345-5317
Fax:	(416) 345-5866
E-mail:	Regulatory@HydroOne.com

b) **The Applicant's counsel:**

Raman Dhillon
Senior Legal Counsel
Hydro One Networks Inc.

Mailing Address: 8th Floor, South Tower
483 Bay Street
Toronto, ON M5G 2P5

Telephone: (416) 859-0942
Fax: (416) 345-6972
E-mail: Raman.Dhillon@HydroOne.com

DATED at Toronto, Ontario, this 31st day of August, 2022.

HYDRO ONE REMOTE COMMUNITIES INC.
By its counsel,

____

Raman Dhillon

CERTIFICATION OF EVIDENCE

TO: ONTARIO ENERGY BOARD

The undersigned, being Hydro One Remote Communities Inc. Managing Director, Kraemer Coulter, hereby certifies for and on behalf of Hydro One Remote Communities Inc. that:

1. I am a senior officer of Hydro One Remote Communities Inc.;
2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (last revised on April 18, 2022)*;* and
3. The evidence, including models and appendices, submitted in support of Hydro One Remote Communities Inc. 2023 distribution rate application (EB-2022-0041) filed with the OEB is accurate, consistent and complete to the best of my knowledge.

DATED this 31st day of August 2022.

____

KRAEMER COULTER

This page has been left blank intentionally.

CERTIFICATION REGARDING PERSONAL INFORMATION

TO: ONTARIO ENERGY BOARD

The undersigned, Hydro One Remote Communities Inc. Managing Director, Kraemer Coulter hereby certifies for and on behalf of Hydro One Remote Communities Inc. that:

1. I am a senior officer of Hydro One Remote Communities Inc.;
2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's Filing Requirements for Electricity Distribution Applications (last revised on April 18, 2022); and,
3. The evidence submitted does not contain any personal information filed herein (as that phrase is defined in the Freedom of Information and Protection of Privacy Act), that is not otherwise redacted in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

DATED this 31st day of August, 2022.

____

KRAEMER COULTER

This page has been left blank intentionally.

CERTIFICATION OF DEFERRAL AND VARIANCE ACCOUNT BALANCES

TO: ONTARIO ENERGY BOARD

I, Chris Lopez, Hydro One's Chief Financial Officer, hereby certify for and on behalf of Hydro One Remote Communities Inc. that:

1. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (last revised on April 18, 2022)*;* and
2. Hydro One has the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts.

DATED this 31st day of August, 2022.

____

CHRIS LOPEZ

This page has been left blank intentionally.

GENERATION & DISTRIBUTION SYSTEM OVERVIEW

1.0 INTRODUCTION

Hydro One Remote Communities Inc. (Remotes) is an integrated generation and distribution company licensed to provide electricity within 21 isolated communities and one grid-connected community in northern Ontario (ED-2003-0037 and EG-2003-0138). Consistent with the Board's Decision in RP-1998-0001, Remotes is 100% debt-financed and is operated as a break-even company with no return on equity.

Information about Hydro One Remotes, its business and the communities it serves can be found Exhibit A, Tab 1, Schedule 4, Attachment 1 and within the Distribution System Plan in section 5.2.1.

This page has been left blank intentionally.

hydro one

REMOTE COMMUNITIES

OUR VISION

We will be the leading electrical utility and a trusted partner to remote communities in Ontario's north.

OUR MISSION

We supply safe, reliable and affordable electricity to remote communities by focusing on continuous improvement, operational excellence and outstanding customer service.

OUR BUSINESS

- Hydro One Remote Communities Inc. – often referred to as "Remotes" – is a subsidiary of Hydro One Inc. We combine the advantages of a large company's expertise in the energy sector, with the intimacy and excellent customer service of a small business.
- We generate and distribute electricity to thousands of customers in many remote communities in Ontario's Far North.
- Most of the communities we serve are "off-grid", meaning they are not connected to the electricity grid. Currently, the most reliable and cost effective method to generate power in these remote communities is using diesel generators.
- Northerners can depend on us for safe, reliable and affordable power.
- The Remote Communities team is made up of over 50 highly trained and skilled employees, including engineers, mechanics, line maintainers, electricians and technicians stationed in Thunder Bay.
- Since the cost of living in the north is high, we operate our business to break-even and we do not make a profit.

IN COMMUNITIES

- The majority of the communities we serve are First Nations and many of our suppliers and contractors are First Nation enterprises.
- We work closely with First Nations communities and Band Councils to help them meet their electricity needs.
- We provide local employment opportunities hiring local First Nations Operators to work in our generating plants, local meter readers, as well as cleaning staff and other services.

OUR CUSTOMERS

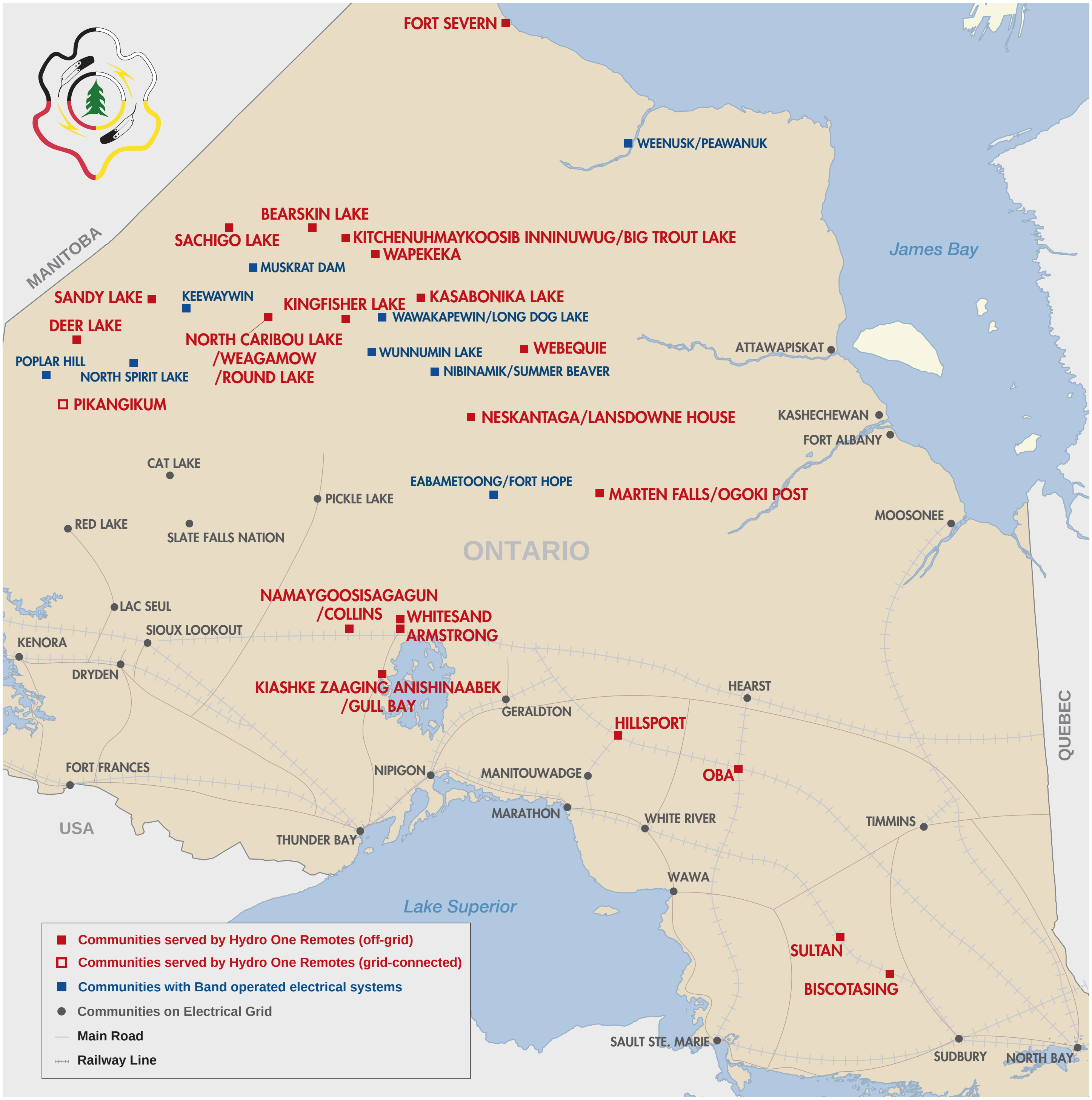
- We understand that the cost of living in the north is high. The communities we serve have the lowest electricity rates in Ontario!
- When customers call our office, they can expect a caring person to answer the phone within 30 seconds. Our dedicated team is always eager to help.
- Our monthly bills are affordable and we will work with customers to help make paying them easier.

ENVIRONMENT

- We respect the land and water and work hard to reduce the overall environmental impact of our business.
- We invest in renewable generation and offer the communities we serve the opportunity to sell renewable electricity to us.
- We are an environmental leader, recognized provincially and nationally for our achievements.
- We have been registered to the ISO 14001 environmental standard since 2002 and continue to improve our operations every year.

SAFETY & RELIABILITY

- Our goal is to ensure that the power is there when you reach for the switch.
- Our generation availability is 99.99%, putting our reliability in the top 25% of comparable companies across Canada.
- Our public safety program helps raise awareness of the dangers of electricity. We work with schools to ensure children know how to stay safe around electricity.
- We respond to emergency power outages 24 hours a day, 7 days a week.



22 COMMUNITIES
17 First Nations • 14 air access only

4,500 +CUSTOMERS

19,000+ PEOPLE ARE PROVIDED POWER

2 MINI HYDRO STATIONS

20 DISTRIBUTION SYSTEMS

57 DIESEL GENERATORS

ENVIRONMENTAL LEADER: ISO 14001 STANDARD

Over 20ML of FUEL USED EACH YEAR

17 CUSTOMER-OWNED RENEWABLE PROJECTS IN SERVICE

HydroOneRemotes.ca

Power outages & emergencies 1-888-825-8707

Service Inquiries 1-888-825-8707

Billing Inquiries 1-800-465-5085

PERFORMANCE MANAGEMENT

1.0 INTRODUCTION

The Board has established specific measures and four key areas of performance for Electrical Distribution Utilities. The key performance areas are:

- Customer focus;
- Operational effectiveness;
- Public policy and responsiveness; and
- Financial performance.

Remotes manages its business based on the principles of continuous improvement established under the rigorous and structured ISO (International Organization for Standardization) framework, taking a disciplined approach to continuous improvement in all aspects of its operations. Based on its business model and mission and in alignment with the OEB's key performance areas, Remotes is focused on safety, reliable and affordable electricity, operational excellence, and customer service.

As a result of the unique nature of Remotes' business, the set of performance metrics tracked by Remotes differs relative to those normally tracked by other LDCs. Remotes currently tracks three sets of performance metrics:

- **Custom Metrics set in the previous DSP filing:** In the last DSP filing, Remotes presented several custom performance metrics that were reflective of Remotes' business and operations at the time of filing. Several of these metrics however, will no longer be applicable in subsequent DSPs because of the impact of the Watay Project on Remotes' operations.

- **Internal Performance Metrics**: Remotes internal performance metrics are driven by its strategic goals. There are some similarities between Remotes' internal scorecards metrics and those included in the OEB performance scorecard, however different methods are used to derive these metrics and set targets to better reflect Remotes' unique operating characteristics (e.g., internal reliability metrics account for both generation and distribution, whereas the external OEB reliability metrics are distribution-specific). Internal metrics and targets evolve and change over time to appropriately reflect Remotes' operations, strategic objectives and priorities.

- **External Performance Metrics**: The external performance metrics are driven by external requirements and regulatory obligations, and include metrics as outlined in the OEB performance scorecards, the Distribution System Code (DSC) and the OEB's reporting and record keeping requirements (RRR). However, due to the unique nature of Remotes' business, Remotes is exempt from certain requirements that are not applicable to its operations.

A detailed discussion of Remotes' performance over the historical period across these three sets of performance metrics, along with targets for 2022 is presented in Section 5.2.3 of the DSP. Remotes 2021 regulatory scorecard and associated discussion of its historical performance can be found in Exhibit A, Tab 1, Schedule 5, Attachment 1.

As discussed in Exhibit A, Tab 2, Schedule 1, Remotes is exempt from evidence requirements related to the Chapter 2 Filing Requirements for the econometric benchmarking studies and Activity and Performance-based Benchmarking (APB) studies and reports from the Pacific Economics Group Research LLC (PEG). Notwithstanding these exemptions, below is a summary of Remotes' approved IRM increases for each of the historical years between the last rebasing application and the current application.

- EB-2018-0043 – 2019 Rates, +1.5%
- EB-2019-0045 – 2020 Rates, +1.5%
- EB-2020-0032 – 2021 Rates, +2.2%
- EB-2021-0034 – 2022 Rates, +3.3%

This page has been left blank intentionally.

Scorecard - Hydro One Remote Communities Inc.

8/11/2022

Performance Outcomes	Performance Categories	Measures		2017	2018	2019	2020	2021	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		90.59%	95.33%	100.00%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time								90.00%	
		Telephone Calls Answered On Time		100.00%	100.00%	100.00%	100.00%	100.00%		65.00%	
	Customer Satisfaction	First Contact Resolution		100	100%	100%	100%	100%			
		Billing Accuracy		97.89%	97.90%	96.88%	94.28%	89.35%		98.00%	
		Customer Satisfaction Survey Results		90	90%	93%	93%	96%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		70.40%	70.40%	72.38%	72.38%	73.93%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		7.55	4.94	6.58	8.27	6.72			7.40
		Average Number of Times that Power to a Customer is Interrupted [2]		3.98	2.02	3.69	3.42	3.33			4.18
	Asset Management	Distribution System Plan Implementation Progress		83%	100%	98%	108%	88%			
	Cost Control	Efficiency Assessment									
		Total Cost per Customer [3]									
		Total Cost per Km of Line [3]									
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time [4]				100.00%					
		New Micro-embedded Generation Facilities Connected On Time								90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.80	1.00	0.98	1.02	0.75			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio									
		Profitability: Regulatory Return on Equity	Deemed (included in rates)								
			Achieved								

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. Value displayed for 2021 reflects data from the first quarter, as the filing requirement was subsequently removed from the Reporting and Record-keeping Requirements (RRR).

Legend:
5-year trend: up, down, flat
Current year: target met, target not met

Fiscal 2021 Scorecard Management Discussion and Analysis ("2021 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2021 Scorecard MD&A: **http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf**

Scorecard MD&A - General Overview

Hydro One Remote Communities Inc. (Remotes) is an integrated generation and distribution company in northern Ontario serving 4,368 customers in 21 off-grid communities and distributes to one community connected to the Province's electricity grid. The communities served by Remotes are isolated and scattered across the far North of Ontario. As compared to other Ontario distributors, Remotes has unique financial, operational, and geographical attributes.

Remotes is 100% debt-financed and conducts its operations under a cost-recovery model to achieve a break-even result of operations. Any surplus or deficiency in revenues is added to or drawn from the Rural or Remote Rate Protection Variance Account for future disposition by the Ontario Energy Board (OEB). Seventeen of the communities are First Nations which are served under agreements with the federal government. In these communities, the federal government funds capital associated with load growth. Replacement capital, operations, maintenance, and administrative costs are funded through Remotes' revenue requirement.

Due to the lack of grid connection in all but one community, most of the electricity that Remotes distributes is produced utilizing diesel combustion engines which is currently the most feasible smaller-scale generation technology for the communities served by Remotes. Remotes also operates two small run-of-the-river hydroelectric plants and at the end of 2021 had 18 customer/community-owned solar installations connected to its distribution systems. Diesel fuel is Remotes' single largest cost. Fuel costs are inherently volatile and related to changes in commodity price, method of delivery and volumes required to generate sufficient electricity to meet customer needs. The feasibility of using further renewable technologies is continually examined as new technologies evolve, but diesel is currently the most reliable and cost-effective technology.

Fourteen communities are not accessible by year-round road and can be reached only by aircraft, winter road or in the case of two communities, also by barge. The size and isolation of Remotes' service territory means that the transportation and accommodation of staff, fuel and equipment is a key driver of Remotes' costs. The use and viability of winter roads to reach these communities is a major cost variable within Remotes' operations. Construction and project risk is high, due to the lack of transportation infrastructure.

Since Remotes is an integrated generation company with unique financing and operations, some metrics are not included in the Scorecard results. The OEB has recognized that Remotes is not directly comparable to other Ontario distributors. In its Decision in EB-2014-0084, the OEB noted that, "Hydro One Remotes is excluded from the Board's benchmarking analysis because of its unique circumstances. As noted in Hydro One Remotes' 2014 Price Cap Incentive Rate application (EB-2013-0142), Hydro One Remotes is unique in terms of its operating characteristics and cost recovery due to the Rural or Remote Electricity Rate Protection."

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2021, Remotes processed 101 new connection requests for residential and small business low-voltage customers (those with service less than 750 Volts), which is similar to the previous year. 100% of these requests were completed within five business days or as agreed to by the customer and the distributor, exceeding the industry target of 90%. Despite COVID-19 pandemic challenges, services connected on time results were comparable to 2020.

- **Scheduled Appointments Met On Time**

Due to high transportation costs and uncertainty about flight availability/ability to land, Remotes does not schedule appointments with customers. Work is generally organized through Band Councils or contractors since most customers are not directly in control of or responsible for housing connections. As a result, no appointments are missed or rescheduled.

- **Telephone Calls Answered On Time**

Remotes' billing and customer service staff received 5,228 phone calls from customers in 2021 and answered 100% of these calls on time, as prescribed in the OEB Distribution System Code (DSC). Sections 7.6.2 and 7.6.3 of the DSC require call centre staff to answer calls within 30 seconds, 65% of the time, on a yearly basis, whenever the customer reaches an agent either directly or by means of a transfer. Remotes does not use an automated Interactive Voice Response (IVR) system and therefore does not report the abandoned call metric. Overall call volume was up from 2020 as a result of the resumption of collection activities.

Customer Satisfaction

- **First Contact Resolution**

First Contact Resolution (FCR) reports the success of the distributor in resolving a customer's issue during the first contact. Remotes measures FCR based on the number of issues that can be resolved by the billing agent as compared to those that must be brought to a supervisor for resolution. In 2021, 100% of calls were resolved by the billing agents and customer service staff without a supervisor's intervention, similar to the prior year.

- **Billing Accuracy**

Remotes issued 48,977 bills in 2021 with an accuracy rate of 89.35%, a decrease compared to previous years due to difficulty in getting meter reads in several communities due to COVID-19 restrictions and community safety protocols. Historically, Remotes does not meet the industry standard of 98.00%. This is largely because Remotes has not installed a smart meter network due to limited communication infrastructure in its service territory and therefore relies on manual readings. Manual readings are more likely to result in higher planned and unplanned estimates. Remotes generally contracts with local community members to read the meters. Readings are then faxed or emailed to the office and entered into the system by the billing team. If the readings are late or not performed, they result in an unplanned estimate. There were 5,218 unplanned estimates in 2021 due to difficulty in getting meter reads in several communities because of on-going COVID restrictions and community safety protocols, which was generally resolved in early 2022. Remotes has also continued with at least quarterly physical meter readings for seasonal customers, but there are a number of seasonal customers whose meters are inaccessible at certain times of the year, making the industry standard difficult to attain.

- **Customer Satisfaction Survey Results**

Remotes conducts biennial surveys of its customers to plan work and respond to customer priorities. Remotes engaged a professional research company with the ability to speak First Nation languages to conduct a random telephone survey of its customers in 2022 for 2021 reporting. When asked "Overall, are you very satisfied, satisfied, dissatisfied or very dissatisfied with the electricity service you get from Hydro One Remotes?" 96% reported being satisfied or very satisfied. The main reason for the positive satisfaction rating was consistent reliability and supply of electricity.

Safety

- **Public Safety**

In April 2015, the Electrical Safety Authority (ESA) made recommendations to the OEB for a scorecard of public safety measure that includes three main components: A) Public Awareness of Electrical Safety, B) Compliance with Ontario Regulation 22/04 under the *Electricity Act, 1998*, and C) the Serious Electrical Incident Index. Components B and C were reported in previous years, and results for *Component A – Public Awareness of Electrical Safety* were tracked for the first time for fiscal 2015 performance.

- **Component A – Public Awareness of Electrical Safety**

  In the spring of 2022, Remotes engaged a professional research company to conduct a random phone survey to gauge electrical safety awareness among people living in its service territory. The survey was designed by the ESA and assessed participants' safety awareness in six core areas: the likelihood to call before digging, the impacts of touching a power line, safe distances when around power lines, safe distances when around downed power lines, danger of tampering with electrical equipment, and actions to be taken when an occupied vehicle is in contact with a power line. For 2021, the Company reported an overall index score of 73.93%, up slightly from prior years. Most respondents understood the danger of touching an overhead wire (87%). However, many customers did not generally recognize the risk of underground wires, since there are very few underground services in Remotes' service territory. Remotes has undertaken educational efforts that include: warning signs at hydroelectric and diesel generating stations; radio ads; school or community presentations and information on electrical hazards in bill inserts; and expects to continue such efforts in the future.

- **Component B – Compliance with Ontario Regulation 22/04, made under the *Electricity Act, 1998***

  Ontario Regulation 22/04 was introduced in early 2004 following recommendations from the ESA to enhance electrical safety for the people of Ontario. The Regulation sets the basis for the requirements for the safe operation of the distribution system in Ontario. Distribution companies are required to be audited yearly on the design, construction, and maintenance of distribution systems in accordance with the Regulation. An external auditor performs the audit. A final report, along with a signed declaration of compliance to the regulation for all sections that are not covered by the audit, is provided to the ESA. The performance target for compliance with the Regulation is for the distributor to be fully compliant, and is recorded as Compliant (C), Non-Compliant (NC), or Needs Improvement (NI). For 2021, Remotes met the performance target and received a Compliant (C) score.

- **Component C – Serious Electrical Incident Index**

  For 2021, the ESA identified no recordable serious public incidents, resulting in an index value of 0.0 for Remotes. The Serious Electrical Incident Index was designed to track and help improve public electrical safety on the distribution systems over time. Based on the distributor's total kilometers of line, the measure normalizes serious electrical incidents per 10, 100, or 1,000 km of line, reporting both the actual number and rate of incidents per kilometer – for Remotes, the index is normalized per 260 km of line. The distributor and any of its contractors or operators are required to report any serious electrical incident to the ESA within 48 hours. A serious electrical incident is defined as any electrical contact or any fire or explosion that caused or may have caused injury or death in any part of the distribution system operating at greater than 750 Volts (except if caused by lightning strikes). Remotes maintains a policy of reporting all public safety incidents to the ESA.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted[1]**

For 2021, Remotes reported an average outage duration of 6.72 hours, which is 1.55 hours better than 2020 (8.27) and 0.68 hours better than the OEB target of 7.40. The stronger performance over the previous year was due to less impactive adverse weather events. The performance over the OEB target improved due to decreased scheduled outages and defective equipment, offset by an increase in tree contacts. The metric represents the average duration of customer interruptions, as the ratio of total customer hours of interruption to the total number of customers served and expressed as the average time in hours over the reporting period.

- **Average Number of Times that Power to a Customer is Interrupted[1]**

The frequency of customer outages was reported at 3.33 outages per customer in 2021, which is 0.09 outages per customer better than in 2020 (3.42). 2021 performance is better than the OEB target of 4.18 largely due to decreased scheduled outages. This metric represents the average frequency of customer interruptions, as the ratio of total number of customer interruptions to the total number of customers served and expressed as the average number of customer interruptions over the reporting period.

For the above two metrics, the impacts due to force majeure events and loss of supply events are excluded.

Asset Management

- **Distribution System Plan Implementation Progress**

The Distribution System Plan (DSP) implementation progress is a distributor-defined performance metric. In 2017, Remotes filed its first formal DSP with the OEB. The metric currently used is Operation Maintenance and Administration (OM&A) and Capital spending to plan for both generation and distribution. In 2021, the target was not met due to decreased spend on OM&A projects, some of which were impacted by the COVID pandemic, as $31.2M was spent compared to a plan of $35.5M (88%). In 2020, $32.4M was spent, compared to a plan of $30.1M (108%). Unlike previous years, the most recent DSP expanded capital metrics beyond more traditional distribution capital spending.

---

[1] The distributor specific target for Hydro One Remotes is located on the OEB Scorecard and is based on the currently approved Distribution System Plan.

Cost Control

The OEB has recognized that Remotes is not directly comparable to other Ontario distributors. In its decision in EB-2014-0084, the OEB noted, "Hydro One Remotes is excluded from the Board's benchmarking analysis because of its unique circumstances. As noted in Hydro One Remotes' 2014 Price Cap Incentive Rate application (EB-2013-0142), Hydro One Remotes is unique in terms of its operating characteristics and cost recovery due to the Rural or Remote Electricity Rate Protection."

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

Due to technical challenges associated with integrating renewable generation in isolated distribution systems, provincial renewable programs have not been available to customers in Remotes' service territory. Remotes offers a program to allow renewable generation to connect to its distribution systems, but most of the installations are small and most do not require a Connection Impact Assessment (CIA).

- **New Micro-embedded Generation Facilities Connected on Time**

This metric measures the company's success in connecting micro-embedded generation facilities (10kW or less) 90% of the time within a five business-day window, or at such later date as agreed to by a micro-embedded generator and the distributor, of the generator informing the distributor that it has satisfied all applicable service conditions and received all necessary approvals, as per sections 6.2.7 and 6.2.7A of the DSC. No new micro-embedded generation facilities were connected to Remotes' distribution systems during 2021.

Financial Ratios

Remotes is 100% debt-financed and is operated as a break-even company with no meaningful return on equity. Therefore, given its financial structure, along with its unique operating characteristics, financial ratios are not comparable with those of other Ontario distribution utilities.

Note to Readers of Fiscal 2021 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance.

Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “can”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements and information. Such statements include, but are not limited to, references to educational efforts, and industry and internal targets. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Some of the factors that could cause such differences include the scope and duration of the COVID-19 pandemic and related developments including government and the company’s response and mitigation measures, legislative or regulatory developments, government policy and program developments, an unexpected increase in call centre volumes, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgment on the reporting date of the performance scorecard, and could be markedly different in the future. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

FACILITATING INNOVATION

1.0 INTRODUCTION

Customers in Remotes' service territory are committed to environmental protection and are interested in developing renewable energy resources to replace diesel generation in their communities. Remotes developed a small renewable energy program called REINDEER (**R**enewable **E**nergy **IN**novation **D**i**E**sel **E**mission **R**eduction) that allows customers to participate in renewable energy projects within Remotes' service territory.

2.0 REINDEER PROGRAM

In response to growing interest from communities in developing renewable generation, Remotes developed the REINDEER Program Standard Guideline. The integration of renewable energy into isolated distribution systems must be carefully managed to ensure that the flow of electricity is controlled, and power quality maintained for end-use customers. To limit the time and cost required for engineering review of each project, the guideline establishes project sizes based on the smallest diesel generator in each community. This approach ensures that electricity can be controlled by the diesel generation, ensuring end-use power quality, and limits the cost to review each application. Larger projects require additional engineering design to ensure the delivery of safe, reliable electricity in the communities.

As a result of these efforts and government funding to support renewable projects in the north, communities have taken advantage of the program. Since Remotes' first install in 2014, there are 18 customer-owned renewable projects (12 net metering and 6 stand-alone), totaling 951.5kW, all of which are solar installations. Rooftop solar installations (ranging from 10 to 20 kW) on community buildings are the most common, most of which were installed in 2014 to 2016 with the support of the Eco-energy program. Larger installations include the Deer Lake School, Fort Severn solar farm and the Gull Bay/KZA solar micro-grid.

The REINDEER program and the Standard Guideline are described in additional detail in Exhibit A, Tab 1, Schedule 6, Attachments 1 and 2. Further detail about the REINDEER renewable program can also be found in sections 5.2.2.4, 5.3.4, and 5.3.5.5 in the DSP (Exhibit B, Tab 2, Schedule 1).

RENEWABLE ENERGY

REINDEER RENEWABLE ENERGY PROGRAM AT HYDRO ONE REMOTES



TWO TYPES OF RENEWABLE PROJECTS AVAILABLE

- Must use a renewable resource
- Must have First Nation participation/support (if in a First Nation community)
- Project must be sized according to the electrical needs of the community and to the kW size of existing generation in the community

"NET" METERING

- Production of renewable energy "nets" or offsets building energy use
- Customer/owner enjoys lower energy bills
- Currently a typical net metering installation is on a Standard "A" Community-owned building (school, water treatment plant, etc.) as these buildings are charged the highest rates
- As of May 1, 2022, Standard "A" rates over 250 kWh are as follows:
  - Air Access – 110.77 cents/kWh
  - Road/Rail – 76.60 cents/kWh
  - Grid Connected – 34.70 cents/kWh *(all kWhs)*
- Projects must be sized according to the facility's load and may not exceed 50% of annual energy consumption
- Available for grid-connected and non-grid connected communities

STAND-ALONE

- Payments are made for kWh injected into Remotes' system
- kWh rate is based on 3 year historical average cost of fuel per kWh (avoided cost of fuel) specific to that community
- 2022 rates range from 21.2 cents/kWh to 81.3 cents/kWh with most communities in the 40 cent range
- Customer/owner gets paid quarterly
- Only available for non-grid connected communities

Hydro One Remote Communities

**For more information contact Remotes Customer Service
1-888-825-8707 or RemotesCustomerService@HydroOne.com**

"REINDEER" Guidelines *(Effective May 1, 2022)*

Renewable **E**nergy **IN**novation **D**i**E**sel **E**mission **R**eduction Program for Hydro One Remotes' Communities

Background

Hydro One Remote Communities Inc. (Hydro One Remotes) is based in Thunder Bay and provides energy services, primarily through diesel generation, to over 4200 customers in 22 remote northern communities - the majority of which are not connected to the provincial electricity grid. The REINDEER programs were developed by Hydro One Remotes to enable the connection of renewable energy projects in its communities in an effort to reduce the impacts of diesel fuel on the environment. There are two types of REINDEER projects:

1. **"Stand-alone"** projects get paid for energy production according to a calculated rate per kilowatt generated. *Available for grid-connected and non-grid connected communities.*

2. "**Net" Metering** projects will receive a reduced monthly bill, and in some situations a credit that expires after 12 months. *Only available for non-grid connected communities.*

This document outlines the general guidelines for a REINDEER project, as well as the specific guidelines for each of the two types of project.

General Guidelines for both types of projects:

- ✓ The REINDEER provider builds, owns, operates and maintains all assets up to and including point of common coupling to Remotes' distribution system or generating station.
- ✓ Hydro One Remotes provides connection access to the distribution system or generation station as applicable provided that the REINDEER project meets technical and metering specifications.
- ✓ Hydro One Remotes' service reliability, customer power quality and existing assets must not be negatively impacted by the connection of the generation facility.
- ✓ REINDEER projects must be sized according to the electricity needs of the community and according to the kilowatt size of the existing energy generation in the community.
- ✓ Hydro One Remotes reserves the right to determine the energy connection point and the configuration to its distribution system.
- ✓ Contract is terminated when the distribution system is connected to the transmission grid.
- ✓ Grid connected proponents should contact the Independent Electricity System Operator (IESO) for current power purchase programs and/or review Ontario Regulation 541/05: Net Metering.
- ✓ 10 year term, renewable in 5 year contracts.
- ✓ Consultation with First Nation communities may be required as directed by Hydro One Remotes.
- ✓ All projects must meet the technical requirements set out in Sections 6.2.25, 6.2.26 and 6.2.27 of the Distribution System Code.
- ✓ All projects are subject to a technical review. The proponent is responsible for paying for the cost of this technical review. Generally, larger projects will require a more comprehensive engineering review.
- ✓ REINDEER project providers must enter into a connection agreement with Hydro One Remotes.
- ✓ All contracts are subject to legal review and must be approved by Managing Director of Hydro One Remotes.

1. "Stand-alone" Project Guidelines

Hydro One Remotes considers a project a "Stand-alone" type project if the installation's primary purpose is to provide additional generation to the community and will feed all of the power produced into Remotes' system. "Stand-alone" projects are available to grid-connected and non-grid connected communites.

Remotes offers to pay the 3 year historical average cost of fuel per kWh produced/avoided cost of fuel specific to that community. The proposed rates as of January, 2022 (based on 2019-2021 annual data) are as follows. All amounts will be paid to the provider quarterly.

REINDEER Stand-alone Rates 2022	
Community	**$/kWh**
Armstrong/Whitesand/Collins	0.212
Bearskin Lake	0.497
Kitchenuhmaykoosib Inninuwug (Big Trout)	0.493
Biscotasing	0.299
Deer Lake	0.418
Fort Severn	0.813
KZA (Gull Bay)	0.259
Hillsport	0.333
Kasabonika Lake	0.442
Kingfisher Lake	0.436
Neskantaga (Lansdowne)	0.419
Marten Falls (Ogoki Post)	0.504
Oba	0.321
Pikangikum	n/a
Sachigo Lake	0.431
Sandy Lake	0.428
Sultan	n/a
Wapekeka	0.560
North Caribou (Weagamow)	0.264
Webequie	0.487

Hydro One Remotes recognizes that its operating environment is unlike any other and the above guideline may not match the unique circumstances of each situation. Because of this:

- *Hydro One Remotes is willing to commit labour and equipment resources, to install, operate and maintain any Stand-alone project, provided that the offered rate is reduced accordingly.*
- *Hydro One Remotes will NOT provide up-front financing or capital contribution at this time.*
- *Hydro One Remotes will also consider asset purchase clauses, during or at expiry of the contract term.*
- *Preference is given to proven technology. Remotes may consider research or innovation projects provided the contract terms are adjusted accordingly.*

- *An engineering review of the connection is required in order to qualify for connection to Hydro One Remotes' distribution system and for the purchase of stand-by power from Hydro One Remotes.*
- *Due to the high cost of connection in Remote communities, it is preferred that large scale renewable projects are located in close proximity to the diesel generating station.*
- *Due to the complexity of integrating energy storage and controls, it is recommended that energy storage systems be directly connected to the diesel generating station buss.*
- *Due to the integration complexity of renewable projects with energy storage, consideration should be given to utilizing Hydro One Remotes to operate and maintain the storage equipment.*
- *Station service required for renewable generation facilities will be net-metered.*
- *Hydro One Remotes reserves the right to assess each project on its own merit and may consider variations of standard terms, provided regulatory and business requirements are met.*
- *Hydro One Remotes reserves the right to withdraw this program and guideline at any time.*

2. "Net" Metering Guidelines

Hydro One Remotes encourages proponents to consider working with First Nations to develop Net Metering projects. Net Metering enables customers to generate their own electricity to reduce the per kWh cost of electricity paid to Hydro One Remotes. "Net" Metering projects are only available to non-grid connected communities.

In order for a project to be considered a Net Metering project, the electricity must be generated primarily for use within the metered facility and meet the following criteria:

1) *Electricity must be generated from a renewable source.*
2) *Projects must be sized according to the facility's load and may not exceed 50% of the current annual energy consumption.*
3) *Project must be sized according to the current locations electrical service capacity. Remotes will not modify the current electrical service to accommodate the renewable technology.*

From time to time, Net Metering projects may send excess generation into Hydro One Remotes' distribution system. Hydro One Remotes will credit the customer's bill for this excess electricity. The bill credits for electricity beyond the customer's own needs will expire after 12 months.

For more information

Potential REINDEER providers looking for additional information on these programs are to contact Customer Service Department, Hydro One Remote Communities Inc. at 1-888-825-8707 (toll free), 807-474-2805 (local) or email RemotesCustomerService@HydroOne.com.

FINANCIAL INFORMATION

1.0 ACCOUNTING STANDARD

On April 3, 2012, the Board issued its Decision with Reasons in EB-2011-0427, granting Remotes' request to use United States Generally Accepted Accounting Principles for regulatory purposes. Based on this decision, Remotes adopted this accounting standard for regulatory purposes.

Remotes confirms that its accounting treatment segregates any non-utility business it conducts from its rate-regulated activities.

2.0 CHANGES TO ACCOUNTING POLICIES

In keeping with good corporate governance, Hydro One reviews and, if appropriate, revises its policies and procedures from time to time. These policies are applicable to Remotes. No financial accounting policy changes have been made that impact the 2023-2027 rate base or revenue requirement since the Board's review of Remotes' distribution revenue requirements and rates for 2018-2022 (EB-2017-0051) other than as specified in this section.

3.0 NON-DISTRIBUTION BUSINESS ACTIVITIES

As discussed in Exhibit A, Tab 1, Schedule 3, Remotes is an integrated generation and distribution company. The accounting treatment used by Remotes segregates the activities between the two segments of generation and distribution.

4.0 AUDITED FINANCIAL STATEMENTS

Remotes' audited financial statements are provided as attachments to this exhibit, as follows:

- Attachment 1: Hydro One Remote Communities Inc. Financial Statements 2018
- Attachment 2: Hydro One Remote Communities Inc. Financial Statements 2019
- Attachment 3: Hydro One Remote Communities Inc. Financial Statements 2020
- Attachment 4: Hydro One Remote Communities Inc. Financial Statements 2021

- Attachment 5: Reconciliation of Regulated Financial Results with Audited Financial Statements 2021
- Attachment 6: 2021 Financial Statements Reconciled to USofA Trial Balance

The most recent annual report and Managements' Discussion and Analysis of Hydro One Networks Inc., Remotes' parent company, can be found at:

- https://www.hydroone.com/investor-relations/2021-annual-report

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2018

To the Directors of Hydro One Remote Communities Inc.

Opinion

We have audited the financial statements of Hydro One Remote Communities Inc. (the "Entity"), which comprise:

- the balance sheet as at December 31, 2018
- the statement of operations and comprehensive income (loss) for the year then ended
- the statement of changes in shareholder's equity (deficit) for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2018, and its results of operations and its cash flows for the year then ended in accordance with US generally accepted accounting principles.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with US generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our

opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 25, 2019

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the years ended December 31, 2018 and 2017

Year ended December 31 *(thousands of Canadian dollars)*	2018	2017
Revenues *(Note 16)*	55,080	51,602
Costs		
Operation, maintenance and administration	19,621	18,708
Fuel used for electric generation	29,406	25,695
Depreciation, amortization and asset removal costs *(Note 4)*	4,261	4,905
	53,288	49,308
Income before financing charges and income taxes	**1,792**	**2,294**
Financing charges *(Notes 5, 16)*	1,794	1,827
Income (loss) before income taxes	**(2)**	**467**
Income tax expense (recovery) *(Note 6)*	(2)	719
Net income (loss) *(Note 6)*	—	**(252)**
Other comprehensive income	17	15
Comprehensive income (loss)	**17**	**(237)**

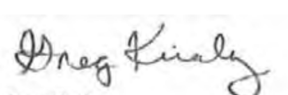
See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS
At December 31, 2018 and 2017

December 31 *(thousands of Canadian dollars)*	2018	2017
Assets		
Current assets:		
Inter-company demand facility *(Note 16)*	2,253	7,482
Accounts receivable *(Notes 7, 16)*	7,586	5,373
Regulatory assets *(Note 9)*	6,136	2,313
Fuel, materials and supplies	3,133	2,400
Income taxes receivable *(Note 6)*	493	446
	19,601	18,014
Property, plant and equipment *(Note 8)*	45,098	44,461
Other long-term assets:		
Regulatory assets *(Note 9)*	34,010	34,039
Deferred income tax assets *(Note 6)*	4,691	4,777
Long-term accounts receivable *(Note 7)*	176	301
Other assets	—	5
	38,877	39,122
Total assets	**103,576**	**101,597**
Liabilities		
Current liabilities:		
Accounts payable	2,934	2,247
Accrued liabilities	9,191	5,383
Accrued interest *(Note 16)*	280	280
	12,405	7,910
Long-term liabilities:		
Long-term debt *(Notes 10, 11, 16)*	42,799	42,790
Post-retirement and post-employment benefit liability *(Note 12)*	13,420	14,144
Regulatory liabilities *(Note 9)*	6,085	4,777
Environmental liabilities *(Note 13)*	29,008	32,134
	91,312	93,845
Total liabilities	103,717	101,755
Contingencies and Commitments (Notes 18, 19)		
Shareholder's equity (deficit)		
Common shares *(Note 14)*	5,000	5,000
Deficit	(4,645)	(4,645)
Accumulated other comprehensive loss	(496)	(513)
Total shareholder's equity (deficit)	(141)	(158)
Total liabilities and shareholder's equity (deficit)	**103,576**	**101,597**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:



Greg Kiraly
Director

Maureen Wareham
Director

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (DEFICIT)
For the years ended December 31, 2018 and 2017

Year ended December 31, 2018 *(thousands of Canadian dollars)*	Common Shares	Deficit	Accumulated Other Comprehensive Loss	Total Shareholder's Equity (Deficit)
January 1, 2018	5,000	(4,645)	(513)	(158)
Net income (loss)	—	—	—	—
Other comprehensive income	—	—	17	17
December 31, 2018	**5,000**	**(4,645)**	**(496)**	**(141)**

Year ended December 31, 2017 *(thousands of Canadian dollars)*	Common Shares	Income (Deficit)	Accumulated Other Comprehensive Loss	Total Shareholder's Equity (Deficit)
January 1, 2017	5,000	(4,393)	(528)	79
Net income (loss)	—	(252)	—	(252)
Other comprehensive income	—	—	15	15
December 31, 2017	**5,000**	**(4,645)**	**(513)**	**(158)**

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2018 and 2017

Year ended December 31 *(thousands of Canadian dollars)*	2018	2017
Operating activities		
Net income (loss)	—	(252)
Environmental expenditures	(942)	(1,285)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	3,868	4,133
Regulatory assets and liabilities	(3,355)	315
Other	24	22
Changes in non-cash balances related to operations *(Note 17)*	(1,262)	979
Net cash from (used in) operating activities	**(1,667)**	**3,912**
Investing activities		
Capital expenditures	(3,892)	(3,523)
Capital contributions received	105	3
Future use assets	225	(163)
Net cash used in investing activities	**(3,562)**	**(3,683)**
Net change in inter-company demand facility	(5,229)	229
Inter-company demand facility, beginning of year	7,482	7,253
Inter-company demand facility, end of year	**2,253**	**7,482**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One Inc. (Hydro One), which is wholly owned by Hydro One Limited. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the Province's electricity grid. The Company's business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On April 12, 2018, the OEB issued the final rate order and approved the 2018 final revenue requirement of $53,834 thousand. The new rates were implemented effective May 1, 2018.

New Service Territory

On December 6, 2018, the OEB amended Hydro One Remote Communities' electricity distribution licence to include the community of Pikangikum within its licensed service area, subject to certain conditions. On December 19, 2018, the community of Pikangikum was connected to a distribution system and the Company began providing service to the community. Full service is expected once all conditions are met.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. The Company uses a cost recovery model applied to achieve breakeven net income and the Financial Statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2018 have been prepared and are publicly available.

Hydro One Remote Communities performed an evaluation of subsequent events through to April 25, 2019, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. No such events or transactions were identified.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, contingencies, unbilled revenues, allowance for doubtful accounts, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations in the period that the assessment is made.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes. Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the RRRP variance account. The balance in the RRRP variance account is subject to future review and disposition by the OEB.

Revenue Recognition

The Company adopted Accounting Standard Codification (ASC) 606 - *Revenue from Contracts with Customers* on January 1, 2018 using the retrospective method, without the election of any practical expedients. There was no material impact to the Company's revenue recognition policy as a result of adopting ASC 606, and no adjustments were made to prior period reported financial statements amounts.

Revenues attributable to the generation and delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Long-term accounts receivable are recorded at their invoiced amount and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. Provision for uncollectible amounts for this component is set at the inception of the balance and is maintained until settlement of those amounts. The provision for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

<u>Deferred Income Taxes</u>

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Statements of Operations and Comprehensive Income (Loss).

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

As approved by the regulator, the Company recovers income tax expense in customer rates based on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax expense is recovered from, or refunded to, customers in current rates, as prescribed by the regulator. The Company records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Balance Sheet as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

<u>Generation</u>

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

<u>Distribution</u>

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices, and metering systems.

<u>Administration and Service</u>

Administration and service assets include administrative buildings, personal computers, tools, and other minor assets.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Statements of Operations and Comprehensive Income (Loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction in Progress

Construction in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2013.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Generation	20 years	3% - 7%	5%
Distribution	46 years	1% - 7%	2%
Administration and service	37 years	3% - 20%	3%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, that are normally retired, is charged to accumulated depreciation with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of Hydro One Remote Communities' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2018 and 2017, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts net of related debt on the Balance Sheet. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income (Loss). Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents net income and OCI in a single continuous Statement of Operations and Comprehensive Income (Loss).

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms.

The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in note 11 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2018 and 2017. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheet and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheet of Hydro One for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets. For the year ended December 31, 2018, the measurement date for all plans was December 31.

Pension Benefits

Hydro One has a contributory defined benefit pension plan (Pension Plan) covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the Pension Plan is accounted for as a defined contribution pension plan and no pension benefit asset or liability is recorded.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the Statements of Operations and Comprehensive Income (Loss).

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in accumulated OCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on the grant date Hydro One Limited common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One Remote Communities records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate, when timing of estimated future expenditures is reliably determinable, that produces an amount at which the environmental liabilities could be settled in an arm’s length transaction with a third party. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One Remote Communities:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact
ASC 606	May 2014 – November 2017	ASC 606 *Revenue from Contracts with Customers* replaced ASC 605 *Revenue Recognition*. ASC 606 provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.	January 1, 2018	On January 1, 2018, the Company adopted ASC 606 using the retrospective method, without the election of any practical expedients. Upon adoption, there was no material impact to the Company's revenue recognition policy and no adjustments were made to prior period reported financial statements amounts. The Company has included the annual disclosure requirements of ASC 606.
ASU 2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company’s employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	The Company applied for a regulatory asset to maintain the capitalization of post-employment benefit related costs and as such, there is no material impact upon adoption. See Note 2 - Significant Accounting Policies and Note 9 - Regulatory Assets and Liabilities.

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact
2016-02 2018-01 2018-10 2018-11 2018-20	February 2016 – December 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under ASC 842 land easements that exist or expired before the entity's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. ASU 2018-10 amends narrow aspects of ASC 842. ASU 2018-11 provides entities with an additional and option transition method in adopting ASC 842. ASU 2018-11 also permits lessors to elect an optional practical expedient to not separate non-lease components from the associated lease component by underlying asset classes. ASU 2018-20 provides relief to lessors that have lease contracts that either require lessees to pay lessor costs directly to a third party or require lessees to reimburse lessors for costs paid by lessors directly to third parties.	January 1, 2019	The Company reviewed its existing leases and other contracts that are within the scope of ASC 842. Apart from the existing leases, no other contracts contained lease arrangements. Upon adoption in the first quarter of 2019, the Company will utilize the modified retrospective transition approach using the effective date of January 1, 2019 as its date of initial application. As a result, comparatives will not be updated. The Company will elect the package of practical expedients and the land easement practical expedient upon adoption. The impact to the Company's financial statements will be the recognition of approximately $21 thousand of a Right-of-Use (ROU) asset and a corresponding lease obligation on the Balance Sheet. The ROU asset and lease obligation will represent the present value of the Company's remaining minimum lease payments for leases with terms greater than 12 months. Discount rates used in calculating the ROU asset and lease obligation correspond to the Company's incremental borrowing rate.
2018-07	June 2018	Expansion in the scope of ASC 718 to include share-based payment transactions for acquiring goods and services from non-employees. Previously, ASC 718 was only applicable to share-based payment transactions for acquiring goods and services from employees.	January 1, 2019	No impact upon adoption
2018-13	August 2018	Disclosure requirements on fair value measurements in ASC 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	Under assessment
2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	Under assessment
2018-15	August 2018	The amendment aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The accounting for the service element of a hosting arrangement is not affected by the amendment.	January 1, 2020	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(thousands of dollars)*	2018	2017
Depreciation of property, plant and equipment	2,926	2,848
Amortization of regulatory assets	942	1,285
Depreciation and amortization	3,868	4,133
Asset removal costs	393	772
	4,261	4,905

5. FINANCING CHARGES

Year ended December 31 *(thousands of dollars)*	2018	2017
Interest on long-term debt	1,958	1,958
Amortization of hedging losses	16	15
Other	15	21
Interest capitalized on construction in progress	(126)	(87)
Interest income on inter-company demand facility	(69)	(80)
	1,794	1,827

6. INCOME TAXES

As a rate-regulated utility company, the Company's effective tax rate excludes temporary differences that are recoverable in future rates charged to customers. Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(thousands of dollars)*	2018	2017
Income (loss) before income taxes	(2)	467
Income taxes at statutory rate of 26.5% (2017 - 26.5%)	—	124
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Non-capital losses	972	—
Depreciation and amortization in excess of capital cost allowance	290	476
Post-retirement and post-employment benefit expense in excess of cash payments	164	269
RRRP variance account	(985)	113
Environmental expenditures	(250)	(341)
Overheads capitalized for accounting but deducted for tax purposes	(141)	(123)
Pension contribution in excess of pension expense	(60)	(72)
Interest capitalized for accounting but deducted for tax purposes	(33)	(23)
Change in valuation allowance	—	(428)
Other	17	1
Net temporary differences	(26)	(128)
Prior year adjustments	2	710
Other permanent differences	22	13
Total income taxes (recovery)	(2)	719

The major components of income tax expense (recovery) are as follows:

Year ended December 31 *(thousands of dollars)*	2018	2017
Current income taxes (recovery)	(2)	719
Deferred income taxes	—	—
Total income taxes (recovery)	(2)	719
Effective income tax rate	100.0%	154.0%

The following table presents a reconciliation of net income (loss) to net income under the cost recovery model:

Year ended December 31 *(thousands of dollars)*	2018	2017
Net income (loss) before income taxes	(2)	467
Income taxes (recovery) under cost-recovery model	(2)	467
Net income under cost-recovery model	—	—
Tax expense	—	252
Net income (loss)	—	(252)

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2018 and 2017, deferred income tax assets and liabilities consisted of the following:

December 31 *(thousands of dollars)*	2018	2017
Deferred income tax assets (liabilities)		
Environmental expenditures	12,671	12,420
Depreciation and amortization in excess of capital cost allowance	5,109	5,981
Post-retirement and post-employment benefits expense in excess of cash payments	4,979	5,236
Regulatory amounts not recognized for tax	(13,947)	(12,952)
Other	1,570	(232)
	10,382	10,453
Less: valuation allowance	(5,691)	(5,676)
Total deferred income tax assets	4,691	4,777

During 2018 and 2017, there was no change in the rate applicable to deferred tax assets and liabilities. The valuation allowance for deferred tax assets as at December 31, 2018 was $5,691 thousand (2017 - $5,676 thousand). The valuation allowance primarily relates to temporary differences for non-depreciable assets. As at December 31, 2018, the Company has non-capital losses of $5,927 thousand, which will begin to expire in 2036.

7. ACCOUNTS RECEIVABLE

December 31, 2018 *(thousands of dollars)*	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable – billed	2,909	176	3,085
Accounts receivable – unbilled	4,736	—	4,736
Accounts receivable, gross	7,645	176	7,821
Allowance for doubtful accounts	(59)	—	(59)
Accounts receivable, net	7,586	176	7,762

December 31, 2017 *(thousands of dollars)*	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable – billed	2,860	308	3,168
Accounts receivable – unbilled	2,601	—	2,601
Accounts receivable, gross	5,461	308	5,769
Allowance for doubtful accounts	(88)	(7)	(95)
Accounts receivable, net	5,373	301	5,674

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2018 and 2017:

Year ended December 31 *(thousands of dollars)*	2018	2017
Allowance for doubtful accounts - beginning	(95)	(198)
Write-offs	57	66
Adjustments to allowance for doubtful accounts	(21)	37
Allowance for doubtful accounts - ending	(59)	(95)

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2018 *(thousands of dollars)*	Property, Plant and Equipment [1]	Accumulated Depreciation	Construction in Progress	Total
Generation	46,840	21,926	1,241	26,155
Distribution	11,085	2,276	336	9,145
Administration and service	13,131	3,333	—	9,798
	71,056	27,535	1,577	45,098

[1] Includes future use assets totalling $1,951 thousand.

December 31, 2017 *(thousands of dollars)*	Property, Plant and Equipment [1]	Accumulated Depreciation	Construction in Progress	Total
Generation	46,439	22,346	1,691	25,784
Distribution	11,047	2,334	258	8,971
Administration and service	12,658	3,142	190	9,706
	70,144	27,822	2,139	44,461

[1] Includes future use assets totalling $2,176 thousand.

Financing charges capitalized on property, plant and equipment under construction were $126 thousand in 2018 (2017 - $87 thousand).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

December 31 *(thousands of dollars)*	2018	2017
Regulatory assets:		
Environmental	35,144	34,447
RRRP variance account	4,541	1,218
Stock-based compensation	461	429
Post-retirement and post-employment benefits	—	258
Total regulatory assets	40,146	36,352
Less: current portion	(6,136)	(2,313)
	34,010	34,039
Regulatory liabilities:		
Deferred income tax regulatory liability	4,691	4,777
Post-retirement and post-employment benefits	1,394	—
Total regulatory liabilities	6,085	4,777
Less: current portion	—	—
	6,085	4,777

Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. The Company has recorded an equivalent amount as a regulatory asset. In 2018, the environmental regulatory asset increased by $907 thousand (2017 - decreased by $1,002 thousand) to reflect related changes in the Company's environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2018 OM&A expenses would have been higher by $907 thousand (2017 - lower by $1,002 thousand). In addition, 2018 amortization expense would have been lower by $942 thousand (2017 - $1,285 thousand), and 2018 financing charges would have been higher by $732 thousand (2017 - $889 thousand).

RRRP Variance Account

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2018, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of cumulative RRRP amounts received. In 2018, RRRP amounts received were lower (2017 - higher) than amounts required to achieve breakeven net income, and as such, the regulatory asset was increased by $3,323 thousand (2017 - reduced by $426 thousand). In the absence of rate-regulated accounting, 2018 revenue would have been lower by $3,323 thousand (2017 - higher by $426 thousand).

Stock-Based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2018 operation, maintenance and administration expenses would have been higher by $22 thousand (2017 - $128 thousand). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheet with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2018 OCI would have been higher by $1,652 thousand (2017 - $2,076 thousand).

Deferred Income Tax Regulatory Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2018 income tax expense would have been higher by approximately $63 thousand (2017 - lower by $411 thousand).

10. LONG-TERM DEBT

Long-term debt represents inter-company debt issued to Hydro One. The following table presents the Company's outstanding long-term debt at December 31, 2018 and 2017:

December 31 *(thousands of dollars)*	2018	2017
3.02% note due 2026	10,000	10,000
5.38% note due 2036	23,000	23,000
4.19% note due 2044	10,000	10,000
	43,000	43,000
Less: Deferred debt issuance costs	(166)	(173)
Less: Net unamortized debt premiums	(35)	(37)
Long-term debt	42,799	42,790

The Company did not issue or repay any long-term debt in 2018 and 2017.

Principal and Interest Payments

Principal repayments, interest payments, and related weighted-average interest rates are summarized by year in the following table:

Years	Long-term Debt Principal Repayments *(thousands of dollars)*	Interest Payments *(thousands of dollars)*	Weighted Average Interest Rate *(%)*
2019	—	1,958	—
2020	—	1,958	—
2021	—	1,958	—
2022	—	1,958	—
2023	—	1,958	—
	—	9,790	—
2024-2028	10,000	9,037	3.0
2029+	33,000	15,777	5.0
	43,000	34,604	4.6

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One Remote Communities classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Remote Communities has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2018 and 2017, the Company's carrying amounts of inter-company demand facility, accounts receivable, and accounts payable are representative of fair value due to the short-term nature of these instruments.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2018 and 2017 is as follows:

December 31, 2018 *(thousands of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	2,253	2,253	2,253	—	—
	2,253	2,253	2,253	—	—
Liabilities:					
Long-term debt	42,799	47,300	—	47,300	—
	42,799	47,300	—	47,300	—

December 31, 2017 *(thousands of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	7,482	7,482	7,482	—	—
	7,482	7,482	7,482	—	—
Liabilities:					
Long-term debt	42,790	49,891	—	49,891	
	42,790	49,891	—	49,891	—

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2018 or 2017.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2018 and 2017, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One Remote Communities did not earn a material amount of revenue from any single customer. At December 31, 2018 and 2017, there was no material accounts receivable balance due from any single customer.

At December 31, 2018, the Company's provision for bad debts was $59 thousand (2017 - $95 thousand). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2018, approximately 24% (2017 - 28%) of the Company's net accounts receivable were outstanding for more than 60 days. The Company's credit risk for accounts receivable is limited to the carrying amounts on its Balance Sheet.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

12. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a DC Plan, a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. Company contributions to the DC Plan for the year ended December 31, 2018 were $10 thousand (2017 - $10 thousand).

Pension Plan and Supplemental Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for The Society of United Professionals (formerly The Society of Energy Professionals Energy Professionals) (Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. Annual Pension Plan contributions for 2018 were $75 million (2017 - $87 million). Estimated annual Pension Plan contributions for the years 2019, 2020, 2021, 2022, 2023 and 2024 are approximately $78 million, $77 million, $78 million, $79 million, $81 million and $83 million, respectively. The most recent actuarial valuation was performed effective December 31, 2017, and the next actuarial valuation will be performed no later than effective December 31, 2020. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for limitations imposed by the *Income Tax Act* (Canada).

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheet, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in accumulated other comprehensive income. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

At December 31, 2018, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,752 million (2017 - $8,258 million). The fair value of pension plan assets available for these benefits was $7,205 million (2017 - $7,277 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2018, Hydro One Remote Communities charged $762 thousand (2017 - $1,062 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $322 thousand (2017 - $495 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2018 were $145 thousand (2017 - $48 thousand). In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $1,652 thousand (2017 - $2,076 thousand) was recorded on the Company's Balance Sheet to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheet within the following line items:

December 31 (thousands of dollars)	2018	2017
Accrued liabilities	389	378
Post-retirement and post-employment benefit liability	13,420	14,144
	13,809	14,522

13. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the years ended December 31, 2018 and 2017:

Year ended December 31 *(thousands of dollars)*	2018	2017
Environmental liabilities - beginning	34,447	35,845
Interest accretion	732	889
Expenditures	(942)	(1,285)
Revaluation adjustment	907	(1,002)
Environmental liabilities - ending	35,144	34,447
Less: current portion	(6,136)	(2,313)
	29,008	32,134

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Balance Sheet after factoring in the discount rate:

December 31 *(thousands of dollars)*	2018	2017
Undiscounted environmental liabilities	35,144	35,581
Less: discounting environmental liabilities to present value	—	(1,134)
Discounted environmental liabilities	35,144	34,447

At December 31, 2018, the estimated future environmental expenditures were as follows:

(thousands of dollars)	
2019	6,136
2020	2,039
2021	2,034
2022	901
2023	913
Thereafter	23,121
	35,144

The Company records a liability for the estimated future expenditures for LAR when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations.

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $35,144 thousand (2017 - $35,581 thousand). These expenditures are expected to be incurred over the period from 2019 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2018 to increase the LAR environmental liability by $907 thousand (2017 - decrease by $1,002 thousand).

14. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2018, the Company had 267 common shares issued and outstanding (2017 - 267).

Dividends

The Company does not pay dividends under its breakeven business model.

15. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Remote Communities, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees of Hydro One Remote Communities.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of The Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore, the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Remote Communities of $1,091 thousand was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2018, 5,092 common shares of Hydro One Limited were issued under the Share Grant Plans (2017 - 3,738) to eligible employees of Hydro One Remote Communities. Total share based compensation recognized by Hydro One Remote Communities during 2018 was $136 thousand (2017 - $187 thousand) and was recorded as a regulatory asset.

A summary of Hydro One Remote Communities' share grant activity under the Share Grant Plans during years ended December 31, 2018 and 2017 is presented below:

Year ended December 31, 2018	Share Grants *(Number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	49,551	$20.50
Vested and issued[1]	(5,092)	—
Forfeited	(995)	$20.50
Share grants outstanding - ending	43,464	$20.50

[1] In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

Year ended December 31, 2017	Share Grants *(Number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	53,721	$20.50
Vested and issued[1]	(3,738)	—
Forfeited	(432)	$20.50
Share grants outstanding - ending	49,551	$20.50

[1] In 2017, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the PWU Share Grant Plan. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2018, Company contributions made under the ESOP were $24 thousand (2017 - $21 thousand).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

During 2018 and 2017, the activity of PSU and RSU awards granted by Hydro One Limited that related to Hydro One Remote Communities were as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2018	2017	2018	2017
Units outstanding – beginning	6,181	2,581	5,211	2,729
Granted	4,895	4,100	3,844	2,912
Vested and issued[1]	(1)	(13)	(2,335)	(13)
Forfeited	(105)	(487)	(119)	(417)
Settled	(636)	—	(396)	—
Units outstanding – ending	10,334	6,181	6,205	5,211

[1] In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the LTIP. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

The grant date total fair value of the awards granted in 2018 was $179 thousand (2017 - $169 thousand). The compensation expense related to the RSU and PSU awards recognized by the Company during 2018 was $153 thousand (2017 - $56 thousand). The expense recognized in 2018 included $16 thousand related to previously awarded PSUs and RSUs to Hydro One's former President and CEO for which costs had not previously been recognized. These awards were settled in 2018 through a one-time cash settlement arrangement.

16. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2018. The IESO is a related party to Hydro One Remote Communities because it is controlled or significantly influenced by the Province.

Year ended December 31 *(thousands of dollars)*			
Related Party	Transaction	2018	2017
IESO	Supply of electricity to remote northern communities - amounts received[1]	35,223	32,259
Hydro One Limited and subsidiaries	Revenues related to the provision of services[2]	404	387
	Costs expensed related to purchase of services[2]	2,262	2,162
	Interest expense on long-term debt	1,958	1,958
	Stock-based compensation costs	289	243
	Interest income on inter-company demand facility	69	80

[1] Consistent with the break even business model, the Company recognized $35,582 thousand as RRRP revenue in 2018 (2017 - $32,514 thousand), with the difference recorded in the regulatory asset RRRP variance account.

[2] The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services.

Transactions with related parties are based on the requirements of the OEB's Affiliate Relationships Code.

The amounts due to and from related parties are as follows:

December 31 *(thousands of dollars)*	2018	2017
Inter-company demand facility	2,253	7,482
Accounts receivable	178	167
Accrued interest	280	280
Long-term debt	42,799	42,790

17. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(thousands of dollars)*	2018	2017
Accounts receivable	(2,213)	184
Fuel, materials and supplies	(733)	76
Income taxes receivable	(47)	17
Long-term accounts receivable	125	344
Other assets	5	19
Accounts payable	687	864
Accrued liabilities	(14)	(2,056)
Post-retirement and post-employment benefit liability	928	1,531
	(1,262)	979

Supplementary Information

Year ended December 31 *(thousands of dollars)*	2018	2017
Net interest paid	1,958	1,958

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid are fully recovered.

18. CONTINGENCIES

Legal Proceedings

Hydro One Remote Communities is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Hydro One and three of its subsidiaries, including Hydro One Remote Communities, are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The action was commenced in the Superior Court of Ontario on September 9, 2015. The plaintiff's motion for certification was dismissed by the court in November 2017. The plaintiff appealed the court's decision to the Divisional Court. The appeal was heard in October 2018; the Divisional Court dismissed the appeal in December 2018; and in January 2019, the plaintiff applied for leave to appeal to the Ontario Court of Appeal.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the Ontario Electricity Financial Corporation (OEFC) holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2018, Hydro One paid approximately $2 million (2017 - $2 million) in respect of consents obtained. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

19. COMMITMENTS

Operating Lease

Hydro One Remote Communities is committed as lessee to an operating lease agreement for use of reserve land to operate a hydro facility for a period of 10 years. During the year ended December 31, 2018, the Company made lease payments totalling $150 thousand (2017 - $120 thousand). The following table presents a summary of Hydro One Remote Communities' commitments under lease agreements due in the next 5 years and thereafter.

December 31, 2018 *(thousands of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Operating lease commitments	150	150	150	150	—	—

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2019

To the Directors of Hydro One Remote Communities Inc.

Opinion on the Financial Statements

We have audited the financial statements of Hydro One Remote Communities Inc. (the "Entity"), which comprise:

- the balance sheet as at December 31, 2019
- the statement of operations and comprehensive income (loss) for the year then ended
- the statement of changes in shareholder's equity (deficit) for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2019, and its results of operations and its cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with U.S generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the

Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 16, 2020

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the years ended December 31, 2019 and 2018

Year ended December 31 *(thousands of Canadian dollars)*	2019	2018
Revenues *(Note 16)*	61,850	55,080
Costs		
Operation, maintenance and administration	21,087	19,621
Cost of power	1,463	—
Fuel used for electric generation	30,251	29,406
Depreciation, amortization and asset removal costs *(Note 4)*	7,229	4,261
	60,030	53,288
Income before financing charges and income tax expense	**1,820**	**1,792**
Financing charges *(Notes 5, 16)*	1,822	1,794
Loss before income tax expense	**(2)**	**(2)**
Income tax expense (recovery) *(Note 6)*	4	(2)
Net loss *(Note 6)*	(6)	—
Other comprehensive income	17	17
Comprehensive income	**11**	**17**

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS
At December 31, 2019 and 2018

December 31 *(thousands of Canadian dollars)*	2019	2018
Assets		
Current assets:		
Inter-company demand facility *(Note 16)*	6,441	2,253
Accounts receivable *(Notes 7, 16)*	7,438	7,586
Regulatory assets *(Note 9)*	3,518	6,136
Fuel, materials and supplies	3,033	3,133
Income taxes receivable *(Note 6)*	25	493
	20,455	19,601
Property, plant and equipment *(Note 8)*	47,907	45,098
Other long-term assets:		
Regulatory assets *(Note 9)*	37,998	34,010
Deferred income tax assets *(Note 6)*	4,583	4,691
Long-term accounts receivable *(Note 7)*	122	176
Other assets	21	—
	42,724	38,877
Total assets	**111,086**	**103,576**
Liabilities		
Current liabilities:		
Accounts payable	7,548	2,934
Accrued liabilities	8,375	9,191
Accrued interest *(Note 16)*	280	280
	16,203	12,405
Long-term liabilities:		
Long-term debt *(Notes 10, 11, 16)*	42,808	42,799
Post-retirement and post-employment benefit liability *(Note 12)*	16,866	13,420
Regulatory liabilities *(Note 9)*	4,637	6,085
Environmental liabilities *(Note 13)*	30,681	29,008
Other liabilities	21	—
	95,013	91,312
Total liabilities	111,216	103,717
Contingencies and Commitments (Notes 18, 19)		
Subsequent Events (Note 20)		
Shareholder's equity (deficit)		
Common shares *(Note 14)*	5,000	5,000
Deficit	(4,651)	(4,645)
Accumulated other comprehensive loss	(479)	(496)
Total shareholder's equity (deficit)	(130)	(141)
Total liabilities and shareholder's equity (deficit)	**111,086**	**103,576**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

David Lebeter
Director

Joseph Cornacchia
Director

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (DEFICIT)
For the years ended December 31, 2019 and 2018

Year ended December 31, 2019 *(thousands of Canadian dollars)*	Common Shares	Deficit	Accumulated Other Comprehensive Loss	Total Shareholder's Equity (Deficit)
January 1, 2019	5,000	(4,645)	(496)	(141)
Net loss	—	(6)	—	(6)
Other comprehensive income	—	—	17	17
December 31, 2019	**5,000**	**(4,651)**	**(479)**	**(130)**

Year ended December 31, 2018 *(thousands of Canadian dollars)*	Common Shares	Income (Deficit)	Accumulated Other Comprehensive Loss	Total Shareholder's Equity (Deficit)
January 1, 2018	5,000	(4,645)	(513)	(158)
Net income (loss)	—	—	—	—
Other comprehensive income	—	—	17	17
December 31, 2018	**5,000**	**(4,645)**	**(496)**	**(141)**

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2019 and 2018

Year ended December 31 *(thousands of Canadian dollars)*	2019	2018
Operating activities		
Net income (loss)	(6)	—
Environmental expenditures	(3,851)	(942)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	6,718	3,868
Regulatory assets and liabilities	(1,495)	(3,355)
Other	26	24
Changes in non-cash balances related to operations *(Note 17)*	8,472	(1,262)
Net cash from (used in) operating activities	**9,864**	**(1,667)**
Investing activities		
Capital expenditures	(4,086)	(3,892)
Capital contributions received	—	105
Future use assets	(1,590)	225
Net cash used in investing activities	**(5,676)**	**(3,562)**
Net change in inter-company demand facility	4,188	(5,229)
Inter-company demand facility, beginning of year	2,253	7,482
Inter-company demand facility, end of year	**6,441**	**2,253**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One Inc. (Hydro One), which is wholly owned by Hydro One Limited. Hydro One Remote Communities generates and distributes electricity to customers in 21 off grid communities in northern Ontario and distributes to one community connected to the Province's electricity grid. The Company's business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On November 5, 2018, Hydro One Remote Communities filed an application with the OEB seeking approval for increased base rates of 1.8%, which was subsequently updated to 1.5% on November 23, 2018, effective May 1, 2019. On February 11, 2019, the OEB issued a draft decision approving the requested increase, which was later finalized on March 28, 2019. On November 15, 2019, Hydro One Remote Communities filed an application with the OEB seeking approval for increased base rates of 2.0% effective May 1, 2020. A decision from the OEB is pending.

New Service Territory

On December 6, 2018, the OEB amended Hydro One Remote Communities' electricity distribution licence to include the community of Pikangikum within its licensed service area, subject to certain conditions. On December 19, 2018, the community of Pikangikum was connected to a distribution system and the Company began providing service to the community. Effective August 14, 2019, all conditions were met and the Company is providing full service to the community.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. The Company uses a cost recovery model applied to achieve breakeven net income and the Financial Statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2019 have been prepared and are publicly available.

Hydro One Remote Communities performed an evaluation of subsequent events through to April 16, 2020, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 20 - Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, contingencies, unbilled revenues, allowance for doubtful accounts, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a subsequent event adjustment.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes. Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the RRRP variance account. The balance in the RRRP variance account is subject to future review and disposition by the OEB.

Revenue Recognition

Revenues attributable to the generation and delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, volume of electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

The Company early-adopted Accounting Standard Update (ASU) 2016-13 *Financial Instruments - Credit Losses* (along with related ASUs as disclosed in Note 3 - New Accounting Pronouncements) with a transition date of January 1, 2019 using the modified retrospective method. Upon adoption, there was no material impact to the Financial Statements, and no adjustments were made to prior period financial statements.

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses (CECL) for all receivable balances. The Company estimates the CECL by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Long-term accounts receivable are recorded at their invoiced amount, net of allowance for doubtful accounts and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. The CECL for this component is set at the inception of the balance and is maintained until settlement of those amounts. The CECL for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

<u>Deferred Income Taxes</u>

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the statements of operations and comprehensive income (loss).

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company recognizes deferred income taxes associated with its regulated operations and records offsetting regulatory assets and liabilities for the deferred income taxes that are expected to be recovered or refunded in future regulated rates charged to customers.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Balance Sheet as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and information technology. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

Generation

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices, and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, tools, and other minor assets.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the statements of operations and comprehensive income (loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction in Progress

Construction in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2013.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Generation	21 years	3% - 7%	4%
Distribution	45 years	1% - 7%	2%
Administration and service	37 years	3% - 20%	3%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, that are normally retired, is charged to accumulated depreciation with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of Hydro One Remote Communities' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2019 and 2018, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts net of related debt on the Balance Sheet. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income (Loss). Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents net income and OCI in a single continuous Statement of Operations and Comprehensive Income (Loss).

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories (i) held-to-maturity, (ii) loans and receivables, (iii) held-for-trading, (iv) other liabilities, or (v) available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. The Company estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible.

The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in note 11 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2019 and 2018. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets o for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income (loss).

<u>Defined Benefit Pension</u>

Hydro One has a contributory defined benefit pension plan (Pension Plan) covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution pension plan and no pension benefit asset or liability is recorded.

<u>Post-retirement and Post-employment Benefits</u>

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in accumulated OCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment for the service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

<u>Share Grant Plans</u>

Hydro One measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited common grant date share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited common grant date share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One Remote Communities records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

Leases

Effective January 1, 2019, the Company adopted Accounting Standards Codification (ASC) 842 - *Leases* using the modified retrospective transition approach using the effective date of January 1, 2019, as its date of initial application. In the Company's transition to ASC 842, the Company elected the package of practical expedients and the land easement practical expedient. As a result, a Right-of-Use (ROU) asset and a corresponding lease obligation of approximately $21 thousand impact to the balance sheet at January 1, 2019 and no adjustments were made to prior period financial statement amounts. There was no material impact to the statement of operations and comprehensive income (loss). On adoption, the Company did not identify any finance leases.

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding ROU asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets are calculated as the difference between the lease expense and the accretion of interest, which is calculated on the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a re-measurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present ASCs and ASUs issued by the Financial Accounting Standards Board that are applicable to Hydro One Remote Communities:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact
ASC 842	February 2016 - January 2019	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet.	January 1, 2019	Hydro One adopted ASC 842 on January 1, 2019 using the modified retrospective transition approach. See Note 2 to the Financial Statements for impact of adoption.
ASU 2018-07	June 2018	Expansion in the scope of ASC 718 to include share-based payment transactions for acquiring goods and services from non-employees. Previously, ASC 718 was only applicable to share-based payment transactions for acquiring goods and services from employees.	January 1, 2019	No impact upon adoption
ASU 2016-13 2018-19 2019-04 2019-05 2019-11	June 2016 - November 2019	The amendments provide users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date.	January 1, 2019	Hydro One early-adopted these ASUs with a transition date of January 1, 2019 using the modified retrospective transition approach. See Note 2 to the Financial Statements for impact of adoption.

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact
ASU 2018-13	August 2018	Disclosure requirements on fair value measurements in ASC 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	No impact upon adoption
ASU 2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	Under assessment
ASU 2019-12	December 2019	The amendments simplify the accounting for income taxes by removing certain exceptions to the general principles and improving consistent application of Topic 740 by clarifying and amending existing guidance.	January 1, 2021	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(thousands of dollars)*	2019	2018
Depreciation of property, plant and equipment	2,867	2,926
Amortization of regulatory assets	3,851	942
Depreciation and amortization	6,718	3,868
Asset removal costs	511	393
	7,229	4,261

5. FINANCING CHARGES

Year ended December 31 *(thousands of dollars)*	2019	2018
Interest on long-term debt	1,958	1,958
Amortization of hedging losses	17	16
Other	37	15
Interest capitalized on construction in progress	(124)	(126)
Interest income on inter-company demand facility	(66)	(69)
	1,822	1,794

6. INCOME TAXES

As a rate-regulated utility company, the Company's effective tax rate excludes temporary differences that are recoverable in future rates charged to customers. Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(thousands of dollars)*	2019	2018
Income (loss) before income tax expense	(2)	(2)
Income tax expense at statutory rate of 26.5% (2018 - 26.5%)	(1)	—
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Non-capital losses	339	972
Depreciation and amortization in excess of capital cost allowance	1,037	290
Post-retirement and post-employment benefit expense in excess of cash payments	221	164
RRRP variance account	(411)	(985)
Environmental expenditures	(1,020)	(250)
Overheads capitalized for accounting but deducted for tax purposes	(139)	(141)
Pension contribution in excess of pension expense	(54)	(60)
Interest capitalized for accounting but deducted for tax purposes	(33)	(33)
Change in valuation allowance	6	—
Other	19	17
Net temporary differences	(35)	(26)
Prior year adjustments	4	2
Other permanent differences	36	22
Total income tax expense (recovery)	4	(2)

The major components of income tax expense (recovery) are as follows:

Year ended December 31 *(thousands of dollars)*	2019	2018
Current income tax expense (recovery)	4	(2)
Deferred income tax expense	—	—
Total income tax expense (recovery)	4	(2)
Effective income tax rate	(200.0)%	100.0%

The following table presents a reconciliation of net income (loss) to net income under the cost recovery model:

Year ended December 31 *(thousands of dollars)*	2019	2018
Net income (loss) before income tax expense	(2)	(2)
Income tax expense (recovery) under cost-recovery model	(2)	(2)
Net income under cost-recovery model	—	—
Income tax expense	6	—
Net income (loss)	(6)	—

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2019 and 2018, deferred income tax assets and liabilities consisted of the following:

December 31 *(thousands of dollars)*	2019	2018
Deferred income tax assets (liabilities)		
Environmental expenditures	12,293	12,671
Depreciation and amortization in excess of capital cost allowance	4,225	5,109
Post-retirement and post-employment benefits expense in excess of cash payments	6,249	4,979
Regulatory amounts not recognized for tax	(14,802)	(13,947)
Other	2,320	1,570
	10,285	10,382
Less: valuation allowance	(5,702)	(5,691)
Total deferred income tax assets	4,583	4,691

During 2019 and 2018, there was no change in the rate applicable to deferred tax assets and liabilities. The valuation allowance for deferred tax assets as at December 31, 2019 was $5,702 thousand (2018 - $5,691 thousand). The valuation allowance primarily relates to temporary differences for non-depreciable assets. As at December 31, 2019, the Company had non-capital losses of $8,404 thousand, which will begin to expire in 2036.

7. ACCOUNTS RECEIVABLE

December 31, 2019 *(thousands of dollars)*	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable – billed	4,026	122	4,148
Accounts receivable – unbilled	3,531	—	3,531
Accounts receivable, gross	7,557	122	7,679
Allowance for doubtful accounts	(119)	—	(119)
Accounts receivable, net	7,438	122	7,560

December 31, 2018 *(thousands of dollars)*	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable – billed	2,909	176	3,085
Accounts receivable – unbilled	4,736	—	4,736
Accounts receivable, gross	7,645	176	7,821
Allowance for doubtful accounts	(59)	—	(59)
Accounts receivable, net	7,586	176	7,762

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2019 and 2018:

Year ended December 31 *(thousands of dollars)*	2019	2018
Allowance for doubtful accounts - beginning	(59)	(95)
Write-offs	72	57
Adjustments to allowance for doubtful accounts	(132)	(21)
Allowance for doubtful accounts - ending	(119)	(59)

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2019 *(thousands of dollars)*	Property, Plant and Equipment [1]	Accumulated Depreciation	Construction in Progress	Total
Generation	48,233	21,406	2,177	29,004
Distribution	12,085	2,654	297	9,728
Administration and service	12,645	3,490	20	9,175
	72,963	27,550	2,494	47,907

[1] Includes future use assets totalling $3,541 thousand.

December 31, 2018 *(thousands of dollars)*	Property, Plant and Equipment [1]	Accumulated Depreciation	Construction in Progress	Total
Generation	46,840	21,926	1,241	26,155
Distribution	11,085	2,276	336	9,145
Administration and service	13,131	3,333	—	9,798
	71,056	27,535	1,577	45,098

[1] Includes future use assets totalling $1,951 thousand.

Financing charges capitalized on property, plant and equipment under construction were $124 thousand in 2019 (2018 - $126 thousand).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

December 31 *(thousands of dollars)*	2019	2018
Regulatory assets:		
Environmental	34,095	35,144
RRRP variance account	6,089	4,541
Stock-based compensation	462	461
Post-retirement and post-employment benefits	870	—
Total regulatory assets	41,516	40,146
Less: current portion	(3,518)	(6,136)
	37,998	34,010
Regulatory liabilities:		
Deferred income tax regulatory liability	4,583	4,691
Post-retirement and post-employment benefits	—	1,394
Tax rule changes variance	54	—
Total regulatory liabilities	4,637	6,085
Less: current portion	—	—
	4,637	6,085

Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. The Company has recorded an equivalent amount as a regulatory asset. In 2019, the environmental regulatory asset increased by $2,802 thousand (2018 - $907 thousand) to reflect related changes in the Company's environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2019 OM&A expenses would have been higher by $2,802 thousand (2018 - $907 thousand). In addition, 2019 amortization expense would have been lower by $3,851 thousand (2018 - $942 thousand), and there would be no impact to 2019 financing charges (2018 - higher by $732 thousand).

RRRP Variance Account

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2019, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of cumulative RRRP amounts received. In 2019 and 2018, RRRP amounts received were lower than amounts required to achieve breakeven net income, and as such, the regulatory asset was increased by $4,120 thousand (2018 - $3,323 thousand). In the absence of rate-regulated accounting, 2019 revenue would have been lower by $4,120 thousand (2018 - $3,323 thousand).

Stock-Based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2019 operation, maintenance and administration expenses would have been higher by $1 thousand (2018 - $22 thousand). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheet with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2019 OCI would have been lower by $2,264 thousand (2018 - higher by $1,652 thousand).

Deferred Income Tax Regulatory Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized a regulatory liability that corresponds to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2019 income tax expense would have been higher by approximately $80 thousand (2018 - $63 thousand).

10. LONG-TERM DEBT

Long-term debt represents inter-company debt issued to Hydro One. The following table presents the Company's outstanding long-term debt at December 31, 2019 and 2018:

December 31 *(thousands of dollars)*	2019	2018
3.02% note due 2026	10,000	10,000
5.38% note due 2036	23,000	23,000
4.19% note due 2044	10,000	10,000
	43,000	43,000
Less: Deferred debt issuance costs	(158)	(166)
Less: Net unamortized debt premiums	(34)	(35)
Long-term debt	42,808	42,799

The Company did not issue or repay any long-term debt in 2019 and 2018.

Principal and Interest Payments

Principal repayments, interest payments, and related weighted-average interest rates are summarized by year in the following table:

Years	Long-Term Debt Principal Repayments *(thousands of dollars)*	Interest Payments *(thousands of dollars)*	Weighted-Average Interest Rate *(%)*
2020	—	1,958	—
2021	—	1,958	—
2022	—	1,958	—
2023	—	1,958	—
2024	—	1,958	—
	—	9,790	—
2025-2029	10,000	8,737	3.0
2030+	33,000	14,119	5.0
	43,000	32,646	4.6

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One Remote Communities classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Remote Communities has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2019 and 2018, the Company's carrying amounts of inter-company demand facility, accounts receivable, and accounts payable are representative of fair value due to the short-term nature of these instruments.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2019 and 2018 is as follows:

December 31, 2019 *(thousands of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt	42,808	51,407	—	51,407	—
	42,808	51,407	—	51,407	—

December 31, 2018 *(thousands of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt	42,799	47,300	—	47,300	—
	42,799	47,300	—	47,300	—

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2019 or 2018.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

<u>Market Risk</u>

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

<u>Credit Risk</u>

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2019 and 2018, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One Remote Communities did not earn a material amount of revenue from any single customer. At December 31, 2019 and 2018, there was no material accounts receivable balance due from any single customer.

At December 31, 2019, the Company's provision for bad debts was $119 thousand (2018 - $59 thousand). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2019, approximately 23% (2018 - 24%) of the Company's net accounts receivable were outstanding for more than 60 days. The Company's credit risk for accounts receivable is limited to the carrying amounts on its balance sheets.

<u>Liquidity Risk</u>

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

12. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a DC Plan, a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the

Income Tax Act (Canada) in the form of credits to a notional account. Company contributions to the DC Plan for the year ended December 31, 2019 were $10 thousand (2018 - $10 thousand).

Pension Plan and Supplemental Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for The Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The next actuarial valuation will be performed no later than effective December 31, 2021. Total Hydro One annual cash Pension Plan employer contributions for 2019 were $61 million (2018 - $75 million). Estimated Hydro One annual Pension Plan employer contributions for the years 2020, 2021, 2022, 2023 and 2024 are approximately $66 million, $65 million, $64 million, $64 million, and $64 million, respectively.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for limitations imposed by the *Income Tax Act* (Canada).

At December 31, 2019, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,973 million (2018 - $7,752 million). The fair value of pension plan assets available for these benefits was $7,848 million (2018 - $7,205 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2019, Hydro One Remote Communities charged $1,012 thousand (2018 - $762 thousand) of post-retirement and post-employment benefit costs to operation, maintenances and administration expenses, and capitalized $431 thousand (2018 - $322 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2019 were $183 thousand (2018 - $145 thousand). In addition, the incremental offset to increase the associated post-retirement and post-employment benefits regulatory assets by $2,264 thousand (2018 - decrease of $1,652 thousand) was recorded on the Company's balance sheet to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the balance sheets within the following line items:

December 31 (thousands of dollars)	2019	2018
Accrued liabilities	467	389
Post-retirement and post-employment benefit liability	16,866	13,420
	17,333	13,809

13. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the years ended December 31, 2019 and 2018:

Year ended December 31 *(thousands of dollars)*	2019	2018
Environmental liabilities - beginning	35,144	34,447
Interest accretion	—	732
Expenditures[1]	(3,851)	(942)
Revaluation adjustment	2,802	907
Environmental liabilities - ending	34,095	35,144
Less: current portion	(3,414)	(6,136)
	30,681	29,008

[1] The 2019 increase in expenditures is primarily due to a large remediation payment made in relation to the community of Pikangikum. The funds were released when the terms of the community acquisition and transfer agreement were satisfied. See Note 1 - Description of Business - New Service Territory.

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the balance sheets after factoring in the discount rate:

December 31 *(thousands of dollars)*	2019	2018
Undiscounted environmental liabilities	34,095	35,144
Less: discounting environmental liabilities to present value	—	—
Discounted environmental liabilities	34,095	35,144

At December 31, 2019, the estimated future environmental expenditures were as follows:

(thousands of dollars)	
2020	3,414
2021	1,088
2022	1,056
2023	971
2024	2,219
Thereafter	25,347
	34,095

The Company records a liability for the estimated future expenditures for LAR when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs, which is its undiscounted amount, required to meet existing legislation or regulations.

As at December 31, 2019, the Company's best estimate of the total estimated future expenditures to complete its LAR program is $34,095 thousand (2018 - $35,144 thousand). These expenditures are expected to be incurred over the period from 2020 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2019 to increase the LAR environmental liability by $2,802 thousand (2018 - $907 thousand).

14. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2019, the Company had 267 common shares issued and outstanding (2018 - 267).

Dividends

The Company does not pay dividends under its breakeven business model.

15. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Remote Communities, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the

IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees of Hydro One Remote Communities.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore, the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Remote Communities of $1,091 thousand was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2019, 5,072 common shares of Hydro One Limited were issued under the Share Grant Plans (2018 - 5,092) to eligible employees of Hydro One Remote Communities. Total share based compensation recognized by Hydro One Remote Communities during 2019 was $105 thousand (2018 - $136 thousand) and was recorded as a regulatory asset.

A summary of Hydro One Remote Communities' share grant activity under the Share Grant Plans during years ended December 31, 2019 and 2018 is presented below:

Year ended December 31, 2019	Share Grants *(Number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	43,464	$20.50
Vested and issued[1]	(5,072)	—
Forfeited	(64)	$20.50
Share grants outstanding - ending	38,328	$20.50

[1] In 2019, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

Year ended December 31, 2018	Share Grants *(Number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	49,551	$20.50
Vested and issued[1]	(5,092)	—
Forfeited	(995)	$20.50
Share grants outstanding - ending	43,464	$20.50

[1] In 2018, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the PWU and the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2019, Company contributions made under the ESOP were $19 thousand (2018 - $24 thousand).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

During 2019 and 2018, the activity of PSU and RSU awards granted by Hydro One Limited that related to Hydro One Remote Communities were as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2019	2018	2019	2018
Units outstanding – beginning	10,334	6,181	6,205	5,211
Granted	—	4,895	—	3,844
Vested and issued[1]	(1,688)	(1)	(1,971)	(2,335)
Forfeited	(59)	(105)	(53)	(119)
Settled	—	(636)	—	(396)
Other[2]	(2,522)	—	(1,804)	—
Units outstanding – ending	6,065	10,334	2,377	6,205

[1] In 2019, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

[2] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, Hydro One Limited removed all executive-related compensation from the labour costs of its regulates subsidiaries. During the year ended December 31, 2019, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Remote Communities.

No awards were granted in 2019. The grant date total fair value of the awards granted in 2018 was $179 thousand. The compensation expense related to the RSU and PSU awards recognized by the Company during 2019 was $162 thousand (2018 - $153 thousand).

16. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.3% ownership at December 31, 2019. The IESO is a related party to Hydro One Remote Communities because it is controlled or significantly influenced by the Ministry of Energy.

Year ended December 31 *(thousands of dollars)*			
Related Party	Transaction	2019	2018
IESO	Supply of electricity to remote northern communities - amounts received[1]	35,223	35,223
Hydro One Limited and subsidiaries	Revenues related to the provision of services[2]	293	404
	Costs expensed related to purchase of services[2]	2,527	2,262
	Interest expense on long-term debt	1,958	1,958
	Stock-based compensation costs	267	289
	Interest income on inter-company demand facility	66	69

[1] Consistent with the break even business model, the Company recognized $39,736 thousand as RRRP revenue in 2019 (2018 - $35,582 thousand), with the difference recorded in the regulatory asset RRRP variance account.

[2] The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services.

Transactions with related parties are based on the requirements of the OEB's Affiliate Relationships Code.

The amounts due to and from related parties are as follows:

December 31 *(thousands of dollars)*	2019	2018
Inter-company demand facility	6,441	2,253
Accounts receivable	104	178
Accrued interest	280	280
Long-term debt	42,808	42,799

17. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(thousands of dollars)*	2019	2018
Accounts receivable	148	(2,213)
Fuel, materials and supplies	100	(733)
Income taxes receivable	468	(47)
Long-term accounts receivable	54	125
Other assets	—	5
Accounts payable	4,614	687
Accrued liabilities	1,906	(14)
Post-retirement and post-employment benefit liability	1,182	928
	8,472	(1,262)

Supplementary Information

Year ended December 31 *(thousands of dollars)*	2019	2018
Net interest paid	1,958	1,958

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid are fully recovered.

18. CONTINGENCIES

Legal Proceedings

Hydro One Remote Communities is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company’s financial position, results of operations or cash flows.

Hydro One and certain of its subsidiaries, including Hydro One Remote Communities, were defendants in a class action suit commenced in 2015 in which the representative plaintiff was seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's application for leave to appeal the lower court's refusal to certify the lawsuit as a class action was denied by the Ontario Court of Appeal on March 26, 2019, which means that the lawsuit has effectively ended.

Hydro One Remote Communities is a defendant in a lawsuit in which the plaintiff Wilderness North Air is seeking $16 million in damages related to allegations of breach of contract following a competitive request for proposals for the supply of diesel fuel. Hydro One Remote Communities is defending itself in the claim and has determined there is a reasonable possibility of liability on the defendant’s part, and if liability is found, the estimated range of losses is between $50 thousand to $400 thousand.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro’s businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the Ontario Electricity Financial Corporation (OEFC) holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2019, Hydro One paid approximately $2 million (2018 - $2 million) in respect of consents obtained. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on Hydro One’s and the Company’s results of operations if Hydro One is not able to recover them in future rate orders.

19. COMMITMENTS

Operating Agreement

Hydro One Remote Communities is committed to an operating agreement related to a hydro facility owned by the Company to pay annual performance payments for a period of 10 years. The operating agreement expires in 2022. During the year ended December 31, 2019, the Company made payments totalling $150 thousand (2018 - $150 thousand). The following table presents a summary of Hydro One Remote Communities’ commitments under this agreement.

December 31, 2019 *(thousands of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Operating agreement	150	150	150	—	—	—

20. SUBSEQUENT EVENTS

Stock-based Compensation

Subsequent to December 31, 2019, Hydro One Limited issued from treasury 2,832 and 5,328 common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the LTIP Plan and Share Grant Plans, respectively.

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2020

To the Directors of Hydro One Remote Communities Inc.

Opinion on the Financial Statements

We have audited the financial statements of Hydro One Remote Communities Inc. (the "Entity), which comprise:

- the balance sheet as at December 31, 2020
- the statement of operations and comprehensive income (loss) for the year then ended
- the statement of changes in shareholder's equity (deficit) for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2020, and its results of operations and its cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with U.S generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 23, 2021

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
For the years ended December 31, 2020 and 2019

Year ended December 31 *(thousands of Canadian dollars)*	**2020**	**2019**
Revenues *(Note 16)*	57,918	61,850
Costs		
Operation, maintenance and administration	21,184	21,087
Cost of power	1,779	1,463
Fuel used for electric generation	29,166	30,251
Depreciation, amortization and asset removal costs *(Note 4)*	4,065	7,229
Gain on disposition of assets	(86)	—
	56,108	60,030
Income before financing charges and income tax expense	**1,810**	**1,820**
Financing charges *(Notes 5, 16)*	1,813	1,822
Loss before income tax expense	**(3)**	**(2)**
Income tax expense (recovery) *(Note 6)*	(3)	4
Net loss *(Note 6)*	—	(6)
Other comprehensive income	18	17
Comprehensive income	**18**	**11**

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS
At December 31, 2020 and 2019

December 31 *(thousands of Canadian dollars)*	**2020**	**2019**
Assets		
Current assets:		
Inter-company demand facility *(Note 16)*	—	6,441
Accounts receivable *(Notes 7, 16)*	8,775	7,438
Regulatory assets *(Note 9)*	3,087	3,518
Fuel, materials and supplies	2,535	3,033
Income taxes receivable *(Note 6)*	20	25
	14,417	20,455
Property, plant and equipment *(Note 8)*	49,816	47,907
Other long-term assets:		
Regulatory assets *(Note 9)*	47,045	37,998
Deferred income tax assets *(Note 6)*	4,493	4,583
Long-term accounts receivable *(Note 7)*	49	122
Other assets	21	21
	51,608	42,724
Total assets	**115,841**	**111,086**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note16)*	42	—
Accounts payable	2,165	7,548
Accrued liabilities	7,640	8,375
Accrued interest *(Note 16)*	280	280
	10,127	16,203
Long-term liabilities:		
Accounts payable	82	—
Long-term debt *(Notes 10, 11, 16)*	42,817	42,808
Post-retirement and post-employment benefit liability *(Note 12)*	17,898	16,866
Regulatory liabilities *(Note 9)*	4,493	4,637
Environmental liabilities *(Note 13)*	40,515	30,681
Other liabilities	21	21
	105,826	95,013
Total liabilities	115,953	111,216
Contingencies and Commitments (Notes 18, 19)		
Shareholder's equity (deficit)		
Common shares *(Note 14)*	5,000	5,000
Deficit	(4,651)	(4,651)
Accumulated other comprehensive loss	(461)	(479)
Total shareholder's equity (deficit)	(112)	(130)
Total liabilities and shareholder's equity (deficit)	**115,841**	**111,086**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

David Lebeter
Director

Joseph Cornacchia
Director

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (DEFICIT)
For the years ended December 31, 2020 and 2019

Year ended December 31, 2020 *(thousands of Canadian dollars)*	**Common Shares**	**Deficit**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity (Deficit)**
January 1, 2020	5,000	(4,651)	(479)	(130)
Net loss	—	—	—	—
Other comprehensive income	—	—	18	18
December 31, 2020	**5,000**	**(4,651)**	**(461)**	**(112)**

Year ended December 31, 2019 *(thousands of Canadian dollars)*	**Common Shares**	**Income (Deficit)**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity (Deficit)**
January 1, 2019	5,000	(4,645)	(496)	(141)
Net loss	—	(6)	—	(6)
Other comprehensive income	—	—	17	17
December 31, 2019	**5,000**	**(4,651)**	**(479)**	**(130)**

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2020 and 2019

Year ended December 31 *(thousands of Canadian dollars)*	**2020**	**2019**
Operating activities		
Net loss	—	(6)
Environmental expenditures	(870)	(3,851)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	3,704	6,718
Regulatory assets and liabilities	312	(1,495)
Other	27	26
Changes in non-cash balances related to operations *(Note 17)*	(5,650)	8,472
Net cash from (used in) operating activities	**(2,477)**	**9,864**
Investing activities		
Capital expenditures	(3,013)	(4,086)
Future use assets	(993)	(1,590)
Net cash used in investing activities	**(4,006)**	**(5,676)**
Net change in inter-company demand facility	(6,483)	4,188
Inter-company demand facility, beginning of year	6,441	2,253
Inter-company demand facility, end of year	**(42)**	**6,441**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One Inc. (Hydro One), which is wholly owned by Hydro One Limited. Hydro One Remote Communities generates and distributes electricity to customers in 21 off grid communities in northern Ontario and distributes to one community connected to the Province's electricity grid. The Company's business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On April 16, 2020, the OEB approved a 2% increase to Hydro One Remote Communities' 2019 base rates for new rates effective May 1, 2020, with a deferred implementation date of November 1, 2020 due to the COVID-19 pandemic (COVID-19 or the pandemic). On October 8, 2020, the OEB authorized Hydro One Remote Communities to implement a rate rider for the recovery of foregone revenues resulting from postponing rate implementation, effective November 1, 2020 until April 30, 2021.

New Service Territory

On December 6, 2018, the OEB amended Hydro One Remote Communities' electricity distribution licence to include the community of Pikangikum within its licensed service area, subject to certain conditions. On December 19, 2018, the community of Pikangikum was connected to a distribution system and the Company began providing service to the community. Effective August 14, 2019, all conditions were met and the Company is providing full service to the community.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. The Company uses a cost recovery model applied to achieve breakeven net income and the Financial Statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2020 have been prepared and are publicly available.

Hydro One Remote Communities performed an evaluation of subsequent events through to April 23, 2021, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, contingencies, and unbilled revenues. Actual results may differ significantly from these estimates.

Since late March 2020, the impact of COVID-19 has been reflected in the Company's financial statements. The Company has analyzed the impact of the pandemic on its estimates and assumptions that affect its financial results as at and for the year ended December 31, 2020 and has determined that there was no material impact.

As the duration of the pandemic remains uncertain, the Company continues to assess its impact to the Company's financial results and operations.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a subsequent event adjustment.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes. Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the RRRP variance account. The balance in the RRRP variance account is subject to future review and disposition by the OEB.

Revenue Recognition

Revenues attributable to the generation and delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, volume of electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses (CECL) for all accounts receivable balances. The Company estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Long-term accounts receivable are recorded at their invoiced amount, net of allowance for doubtful accounts and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. The CECL for this component is set at the inception of the balance and is maintained until settlement of those amounts. The CECL for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

Income Taxes

Income taxes are accounted for using the asset and liability method. Current tax assets and liabilities are recognized based on the taxes payable or refundable on the current and prior year's taxable income. Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date.

Deferred income taxes associated with its regulated operations which are considered to be more-likely-than-not to be recoverable or refunded in the future regulated rates charged to customers are recognized as deferred income tax regulatory assets and liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the balance sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and information technology. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

Generation

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices, and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, tools, and other minor assets.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the statements of operations and comprehensive income (loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction in Progress

Construction in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2013.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Generation	20	3% - 7%	4 %
Distribution	44	1% - 7%	2 %
Administration and service	38	3% - 20%	3 %

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, that are normally retired, is charged to accumulated depreciation with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of Hydro One Remote Communities' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2020 and 2019, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts net of related debt on the balance sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the statements of operations and comprehensive income (loss). Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents net income and OCI in a single continuous statement of operations and comprehensive income (loss).

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories (i) held-to-maturity, (ii) loans and receivables, (iii) held-for-trading, (iv) other liabilities, or (v) available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at its net realizable value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. The Company estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible.

The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in note 11 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2020 and 2019. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and post-employment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.

Defined Benefit Pension

Hydro One has a contributory Pension Plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution pension plan and no pension benefit asset or liability is recorded.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in accumulated OCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment for the service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One Remote Communities records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm’s length transaction with a third party. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standard Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One Remote Communities:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact
ASU 2018-13	August 2018	Disclosure requirements on fair value measurements in Accounting Standard Codification (ASC) 820 are modified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2020	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact
ASU 2018-14	August 2018	Disclosure requirements related to single-employer defined benefit pension or other post-retirement benefit plans are added, removed or clarified to improve the effectiveness of disclosures in financial statement notes.	January 1, 2021	No impact upon adoption
ASU 2019-12	December 2019	The amendments simplify the accounting for income taxes by removing certain exceptions to the general principles and improving consistent application of Topic 740 by clarifying and amending existing guidance.	January 1, 2021	No impact upon adoption
ASU 2020-10	October 2020	The amendments are intended to improve the Codification by ensuring the guidance required for an entity to disclose information in the notes of financial statements are codified in the disclosure sections to reduce the likelihood of disclosure requirements being missed.	January 1, 2021	No impact upon adoption

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(thousands of dollars)*	2020	2019
Depreciation of property, plant and equipment	2,834	2,867
Amortization of regulatory assets	870	3,851
Depreciation and amortization	3,704	6,718
Asset removal costs	361	511
	4,065	7,229

5. FINANCING CHARGES

Year ended December 31 *(thousands of dollars)*	2020	2019
Interest on long-term debt	1,958	1,958
Amortization of hedging losses	18	17
Other	33	37
Interest capitalized on construction in progress	(173)	(124)
Interest income on inter-company demand facility	(23)	(66)
	1,813	1,822

6. INCOME TAXES

As a rate regulated utility company, the Company recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated business. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred income tax expense (recovery). The Company's tax expense or recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable or refunded in future rates charged to customers. Thus, the Company's income tax expense or recovery differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate.

The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(thousands of dollars)*	2020	2019
Loss before income tax expense	(3)	(2)
Income tax expense at statutory rate of 26.5% (2019 - 26.5%)	(1)	(1)
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Non-capital losses	(225)	339
Depreciation and amortization in excess of capital cost allowance	271	1,037
Post-retirement and post-employment benefit expense in excess of cash payments	273	221
RRRP variance account	116	(411)
Environmental expenditures	(231)	(1,020)
Overheads capitalized for accounting but deducted for tax purposes	(152)	(139)
Pension contribution in excess of pension expense	(60)	(54)
Interest capitalized for accounting but deducted for tax purposes	(46)	(33)
Change in valuation allowance	—	6
Other	14	19
Net temporary differences	(40)	(35)
Prior year adjustments	8	4
Other permanent differences	30	36
Total income tax expense (recovery)	(3)	4

The major components of income tax expense (recovery) are as follows:

Year ended December 31 *(thousands of dollars)*	2020	2019
Current income tax expense (recovery)	(3)	4
Deferred income tax expense	—	—
Total income tax expense (recovery)	(3)	4
Effective income tax rate	100.0 %	(200.0)%

The following table presents a reconciliation of net income (loss) to net income under the cost recovery model:

Year ended December 31 *(thousands of dollars)*	2020	2019
Net loss before income tax expense	(3)	(2)
Income tax recovery under cost-recovery model	(3)	(2)
Net income under cost-recovery model	—	—
Income tax expense	—	6
Net loss	—	(6)

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities reflect the future tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and liabilities attributable to the Company's regulated business are recognized with a corresponding offset in deferred income tax regulatory assets and liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. At December 31, 2020 and 2019, deferred income tax assets and liabilities consisted of the following:

As at December 31 *(thousands of dollars)*	2020	2019
Deferred income tax assets (liabilities)		
Environmental expenditures	15,640	12,293
Depreciation and amortization in excess of capital cost allowance	3,448	4,225
Post-retirement and post-employment benefits expense in excess of cash payments	6,623	6,249
Regulatory amounts not recognized for tax	(17,895)	(14,802)
Other	2,370	2,320
	10,186	10,285
Less: valuation allowance	(5,693)	(5,702)
Net deferred income tax assets	4,493	4,583

During 2020 and 2019, there was no change in the rate applicable to deferred tax assets and liabilities. The valuation allowance for deferred tax assets as at December 31, 2020 was $5,693 thousand (2019 - $5,702 thousand). The valuation allowance primarily relates to temporary differences for non-depreciable assets. As at December 31, 2020, the Company had non-capital losses of $9,035 thousand, which will begin to expire in 2036.

7. ACCOUNTS RECEIVABLE

As at December 31, 2020 *(thousands of dollars)*	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable – billed	6,179	49	6,228
Accounts receivable – unbilled	2,920	—	2,920
Accounts receivable, gross	9,099	49	9,148
Allowance for doubtful accounts	(324)	—	(324)
Accounts receivable, net	8,775	49	8,824

As at December 31, 2019 *(thousands of dollars)*	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable – billed	4,026	122	4,148
Accounts receivable – unbilled	3,531	—	3,531
Accounts receivable, gross	7,557	122	7,679
Allowance for doubtful accounts	(119)	—	(119)
Accounts receivable, net	7,438	122	7,560

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2020 and 2019:

Year ended December 31 *(thousands of dollars)*	2020	2019
Allowance for doubtful accounts - beginning	(119)	(59)
Write-offs	98	72
Adjustments to allowance for doubtful accounts	(303)	(132)
Allowance for doubtful accounts - ending	(324)	(119)

8. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2020 *(thousands of dollars)*	Property, Plant and Equipment [1]	Accumulated Depreciation	Construction in Progress	Total
Generation	51,077	23,445	2,842	30,474
Distribution	12,315	2,908	813	10,220
Administration and service	12,743	3,652	31	9,122
	76,135	30,005	3,686	49,816

[1] Includes future use assets totalling $4,534 thousand.

As at December 31, 2019 *(thousands of dollars)*	Property, Plant and Equipment [1]	Accumulated Depreciation	Construction in Progress	Total
Generation	48,233	21,406	2,177	29,004
Distribution	12,085	2,654	297	9,728
Administration and service	12,645	3,490	20	9,175
	72,963	27,550	2,494	47,907

[1] Includes future use assets totalling $3,541 thousand.

Financing charges capitalized on property, plant and equipment under construction were $173 thousand in 2020 (2019 - $124 thousand).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

As at December 31 *(thousands of dollars)*	**2020**	**2019**
Regulatory assets:		
Environmental	43,378	34,095
RRRP variance account	5,598	6,089
Post-retirement and post-employment benefits	569	870
Stock-based compensation	467	462
COVID-19 emergency deferral	120	—
Total regulatory assets	50,132	41,516
Less: current portion	(3,087)	(3,518)
	47,045	37,998
Regulatory liabilities:		
Deferred income tax regulatory liability	4,493	4,583
Tax rule changes variance	—	54
Total regulatory liabilities	4,493	4,637
Less: current portion	—	—
	4,493	4,637

Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. The Company has recorded an equivalent amount as a regulatory asset. In 2020, the environmental regulatory asset increased by $10,153 thousand (2019 - $2,802 thousand) to reflect related changes in the Company's environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2020 OM&A expenses would have been higher by $10,153 thousand (2019 - $2,802 thousand), and 2020 amortization expense would have been lower by $870 thousand (2019 - $3,851 thousand).

RRRP Variance Account

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2020, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of cumulative RRRP amounts received. In 2020, RRRP amounts received were higher (2019 - lower) than amounts required to achieve breakeven net income, and as such, the regulatory asset was reduced by $491 thousand (2019 - increased by $4,120 thousand). In the absence of rate-regulated accounting, 2020 revenue would have been higher by $491 thousand (2019 - lower by $4,120 thousand).

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the balance sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2020 OCI would have been higher by $301 thousand (2019 - lower by $2,264 thousand).

Stock-Based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2020 operation, maintenance and administration expenses would have been higher by $3 thousand (2019 - $1 thousand). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

COVID-19 Emergency Deferral

The COVID-19 emergency deferral account comprises of five sub-accounts established to track incremental costs and lost revenues related to the COVID-19 pandemic: (i) Billing and System Changes as a Result of the Emergency Order Regarding Time-of-Use Pricing, (ii) Lost Revenues Arising from the COVID-19 Emergency, (iii) Other Incremental Costs, (iv) Foregone Revenues from Postponing Rate Implementation, and (v) Bad Debt.

As at December 31, 2020, the Company has recorded a regulatory asset for 2020 foregone revenues that are being collected from ratepayers over the period from November 1, 2020 to April 30, 2021. The Company continues to track certain incremental costs and lost revenues that have arisen due to the COVID-19 pandemic in the other tracking accounts noted above, however, the Company has assessed that these amounts are not probable for future recovery in rates and no amounts related to the COVID-19 pandemic have been recognized as regulatory assets.

Deferred Income Tax Regulatory Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized a regulatory liability that corresponds to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2020 income tax expense would have been higher by approximately $40 thousand (2019 - $80 thousand).

10. LONG-TERM DEBT

Long-term debt represents inter-company debt issued to Hydro One. The following table presents the Company's outstanding long-term debt at December 31, 2020 and 2019:

As at December 31 *(thousands of dollars)*	2020	2019
3.02% note due 2026	10,000	10,000
5.38% note due 2036	23,000	23,000
4.19% note due 2044	10,000	10,000
	43,000	43,000
Less: Deferred debt issuance costs	(150)	(158)
Less: Net unamortized debt premiums	(33)	(34)
Long-term debt	42,817	42,808

The Company did not issue or repay any long-term debt in 2020 and 2019.

Principal and Interest Payments

At December 31, 2020, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

Years	Long-Term Debt Principal Repayments *(thousands of dollars)*	Interest Payments *(thousands of dollars)*	Weighted-Average Interest Rate *(%)*
2021	—	1,958	—
2022	—	1,958	—
2023	—	1,958	—
2024	—	1,958	—
2025	—	1,958	—
	—	9,790	—
2026-2030	10,000	8,433	3.0
2031+	33,000	12,464	5.0
	43,000	30,687	4.6

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One Remote Communities classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Remote Communities has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2020 and 2019, the Company's carrying amounts of inter-company demand facility, accounts receivable, and accounts payable are representative of fair value due to the short-term nature of these instruments.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2020 and 2019 is as follows:

As at December 31, 2020 *(thousands of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt	42,817	55,701	—	55,701	—

As at December 31, 2019 *(thousands of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt	42,808	51,407	—	51,407	—

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2020 or 2019.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2020 and 2019, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One Remote Communities did not earn a material amount of revenue from any single customer. At December 31, 2020 and 2019, there was no material accounts receivable balance due from any single customer.

At December 31, 2020, the Company's allowance for doubtful accounts was $324 thousand (2019 - $119 thousand). The allowance for doubtful accounts reflects the Company's CECL for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. At December 31, 2020, approximately 28% (2019 - 23%) of the Company's net accounts receivable were outstanding for more than 60 days. The Company's credit risk for accounts receivable is limited to the carrying amounts on its balance sheets.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company are expected to be sufficient to fund normal operating requirements.

12. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a DC Plan, a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the Income Tax Act (Canada) in the form of credits to a notional account. Company contributions to the DC Plan for the year ended December 31, 2020 were $10 thousand (2019 - $10 thousand).

Pension Plan and Supplemental Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The next actuarial valuation will be performed no later than effective December 31, 2021. Total Hydro One annual cash Pension Plan employer contributions for the Company in 2020 were $711 thousand (2019 - $693 thousand). The estimated Hydro One annual Pension Plan employer contributions allocated to the Company for the years 2021, 2022, 2023, 2024, 2025, 2026 and 2027 are approximately $692 thousand, $1,053 thousand, $1,110 thousand, $1,156 thousand, $1,163 thousand, $1,190 thousand and $1,240 thousand respectively.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the *Income Tax Act* (Canada).

At December 31, 2020, the present value of Hydro One's projected pension benefit obligation was estimated to be $9,763 million (2019 - $8,973 million). The fair value of pension plan assets available for these benefits was $8,103 million (2019 - $7,848 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2020, Hydro One Remote Communities charged $1,098 thousand (2019 - $1,012 thousand) of post-retirement and post-employment benefit costs to operation, maintenances and administration expenses, and capitalized $512 thousand (2019 - $431 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2020 were $272 thousand (2019 - $183 thousand). In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $301 thousand (2019 - increase of $2,264 thousand) was recorded on the Company's balance sheet to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the balance sheets within the following line items:

As at December 31 (thousands of dollars)	**2020**	**2019**
Accrued liabilities	473	467
Post-retirement and post-employment benefit liability	17,898	16,866
	18,371	17,333

13. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the years ended December 31, 2020 and 2019:

Year ended December 31 *(thousands of dollars)*	2020	2019
Environmental liabilities - beginning	34,095	35,144
Expenditures	(870)	(3,851)
Revaluation adjustment	10,153	2,802
Environmental liabilities - ending	43,378	34,095
Less: current portion	(2,863)	(3,414)
	40,515	30,681

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the balance sheets after factoring in the discount rate:

As at December 31 *(thousands of dollars)*	2020	2019
Undiscounted environmental liabilities	43,378	34,095
Less: discounting environmental liabilities to present value	—	—
Discounted environmental liabilities	43,378	34,095

At December 31, 2020, the estimated future environmental expenditures were as follows:

(thousands of dollars)	
2021	2,863
2022	1,785
2023	1,183
2024	2,315
2025	2,315
Thereafter	32,917
	43,378

The Company records a liability for the estimated future expenditures for LAR when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs, which is its undiscounted amount, required to meet existing legislation or regulations.

As at December 31, 2020, the Company's best estimate of the total estimated future expenditures to complete its LAR program was $43,378 thousand (2019 - $34,095 thousand). These expenditures are expected to be incurred over the period from 2021 to 2057. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2020 to increase the LAR environmental liability by $10,153 thousand (2019 - $2,802 thousand).

14. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2020, the Company had 267 common shares issued and outstanding (2019 - 267).

Dividends

The Company does not pay dividends under its breakeven business model.

15. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Remote Communities, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees of Hydro One Remote Communities.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore, the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Remote Communities of $1,091 thousand was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2020, 5,387 common shares of Hydro One Limited were issued under the Share Grant Plans (2019 - 5,072) to eligible employees of Hydro One Remote Communities. Total share based compensation recognized by Hydro One Remote Communities during 2020 was $115 thousand (2019 - $105 thousand) and was recorded as a regulatory asset.

A summary of Hydro One Remote Communities' share grant activity under the Share Grant Plans during years ended December 31, 2020 and 2019 is presented below:

Year ended December 31, 2020	Share Grants *(Number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	38,328	$20.50
Vested and issued[1]	(5,387)	—
Transfers[2]	2,865	—
Forfeited	(822)	$20.50
Share grants outstanding - ending	34,984	$20.50

[1] In 2020, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

[2] Transfers relate to PWU employees transferred from Hydro One Networks to Hydro One Remote Communities during 2020. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

Year ended December 31, 2019	Share Grants *(Number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	43,464	$20.50
Vested and issued[1]	(5,072)	—
Forfeited	(64)	$20.50
Share grants outstanding - ending	38,328	$20.50

[1] In 2019, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2020, Company contributions made under the ESOP were $22 thousand (2019 - $19 thousand).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

During 2020 and 2019, the activity of PSU and RSU awards granted by Hydro One Limited that related to Hydro One Remote Communities were as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	**2020**	**2019**	**2020**	**2019**
Units outstanding – beginning	6,065	10,334	2,377	6,205
Vested and issued[1]	(2,711)	(1,688)	(12)	(1,971)
Forfeited	(70)	(59)	(46)	(53)
Other[2]	—	(2,522)	—	(1,804)
Units outstanding – ending	3,284	6,065	2,319	2,377

[1] In 2020, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

[2] In 2018, the Province of Ontario issued the *Hydro One Accountability Act* (Accountability Act) that directed compensation related changes for Hydro One Limited as well as amended the *Ontario Energy Board Act* (OEB Act) to restrict the recovery of any executive compensation in the rate approvals of any Hydro One Limited subsidiaries. As a result, to comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulates subsidiaries. During the year ended December 31, 2020, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Remote Communities.

No awards were granted in 2020 or 2019. The compensation expense related to the PSU and RSU awards recognized by the Company during 2020 was $100 thousand (2019 - $162 thousand).

16. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.3% ownership at December 31, 2020. The IESO is a related party to Hydro One Remote Communities because it is controlled or significantly influenced by the Ministry of Energy.

Year ended December 31 *(thousands of dollars)*

Related Party	Transaction	2020	2019
IESO	Supply of electricity to remote northern communities - amounts received[1]	35,223	35,223
	Amounts related to electricity rebates	7,735	3,312
Hydro One Networks Inc.	Revenues related to the provision of services[2]	160	293
	Cost of power	1,665	1,451
	Costs expensed related to purchase of services[2]	3,158	3,332
Hydro One Inc.	Interest income on inter-company demand facility	23	66
	Interest expense on long-term debt	1,958	1,958
	Costs expensed related to purchase of services[2]	23	34
	Stock-based compensation costs	215	267

[1] Consistent with the break even business model, the Company recognized $34,732 thousand as RRRP revenue in 2019 (2019 - $39,736), with the difference recorded in the regulatory asset RRRP variance account.
[2] The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services.

Transactions with related parties are based on the requirements of the OEB's Affiliate Relationships Code.

The amounts due to and from related parties are as follows:

As at December 31 *(thousands of dollars)*	2020	2019
Inter-company demand facility	(42)	6,441
Accounts receivable	767	668
Accrued interest	280	280
Long-term debt	42,967	42,966

17. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(thousands of dollars)*	2020	2019
Accounts receivable	(1,337)	148
Fuel, materials and supplies	498	100
Income taxes receivable	5	468
Long-term accounts receivable	73	54
Accounts payable	(6,120)	4,614
Accrued liabilities	(184)	1,906
Long-term accounts payable	82	—
Post-retirement and post-employment benefit liability	1,333	1,182
	(5,650)	8,472

Supplementary Information

Year ended December 31 *(thousands of dollars)*	2020	2019
Net interest paid	1,958	1,958

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid are fully recovered.

18. CONTINGENCIES

Legal Proceedings

Hydro One Remote Communities is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Hydro One Remote Communities is a defendant in a lawsuit in which the plaintiff Wilderness North Air is seeking $16 million in damages related to allegations of breach of contract following a competitive request for proposals for the supply of diesel fuel. Hydro One Remote Communities is defending itself in the claim and has determined there is a reasonable possibility of liability to the Company, and if liability is found, the estimated range of losses is between $50 thousand to $400 thousand.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the Ontario Electricity Financial Corporation (OEFC) holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2020, Hydro One paid approximately $2 million (2019 - $2 million) in respect of consents obtained. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

19. COMMITMENTS

Operating Agreement

Hydro One Remote Communities is committed to an operating agreement related to a hydro facility owned by the Company to pay annual performance payments for a period of 10 years. The operating agreement expires in 2022. During the year ended December 31, 2020, the Company made payments totalling $150 thousand (2019 - $150 thousand). The following table presents a summary of Hydro One Remote Communities' commitments under this agreement.

December 31, 2020 *(thousands of dollars)*	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Thereafter**
Operating agreement	150	150	—	—	—	—

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2021

To the Directors of Hydro One Remote Communities Inc.

Opinion on the Financial Statements

We have audited the financial statements of Hydro One Remote Communities Inc. (the "Entity), which comprise:

- the balance sheet as at December 31, 2021
- the statement of operations and comprehensive income (loss) for the year then ended
- the statement of changes in shareholder's equity (deficit) for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2021, and its results of operations and its cash flows for the year then ended in accordance with U.S. generally accepted accounting principles.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with U.S generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 27, 2022

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

For the years ended December 31, 2021 and 2020

Year ended December 31 *(thousands of Canadian dollars)*	**2021**	**2020**
Revenues *(Note 16)*	63,271	57,918
Costs		
Operation, maintenance and administration	20,607	21,184
Cost of power	1,584	1,779
Fuel used for electricity generation	34,481	29,166
Depreciation, amortization and asset removal costs *(Note 4)*	4,835	4,065
Gain on disposition of assets	—	(86)
	61,507	56,108
Income before financing charges and income tax expense	**1,764**	**1,810**
Financing charges *(Notes 5, 16)*	1,764	1,813
Loss before income tax expense	—	**(3)**
Income tax expense (recovery) *(Note 6)*	—	(3)
Net loss *(Note 6)*	—	—
Other comprehensive income	19	18
Comprehensive income	**19**	**18**

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS
At December 31, 2021 and 2020

December 31 *(thousands of Canadian dollars)*	**2021**	**2020**
Assets		
Current assets:		
Inter-company demand facility *(Note 16)*	2,540	—
Accounts receivable *(Notes 7, 16)*	8,835	8,775
Regulatory assets *(Note 9)*	3,172	3,087
Fuel, materials and supplies	3,240	2,535
Income taxes receivable *(Note 6)*	18	20
	17,805	14,417
Property, plant and equipment *(Note 8)*	51,796	49,816
Other long-term assets:		
Regulatory assets *(Note 9)*	50,183	47,045
Deferred income tax assets *(Note 6)*	4,429	4,493
Long-term accounts receivable *(Note 7)*	6	49
Other assets	14	21
	54,632	51,608
Total assets	**124,233**	**115,841**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note16)*	—	42
Accounts payable	6,873	2,165
Accrued liabilities	11,317	7,640
Accrued interest *(Note 16)*	280	280
	18,470	10,127
Long-term liabilities:		
Accounts payable	86	82
Long-term debt *(Notes 10, 11, 16)*	42,827	42,817
Post-retirement and post-employment benefit liability *(Note 12)*	17,882	17,898
Regulatory liabilities *(Note 9)*	4,920	4,493
Environmental liabilities *(Note 13)*	40,127	40,515
Other liabilities	14	21
	105,856	105,826
Total liabilities	124,326	115,953
Contingencies and Commitments *(Notes 18, 19)*		
Shareholder's equity (deficit)		
Common shares *(Note 14)*	5,000	5,000
Deficit	(4,651)	(4,651)
Accumulated other comprehensive loss	(442)	(461)
Total shareholder's equity (deficit)	(93)	(112)
Total liabilities and shareholder's equity (deficit)	**124,233**	**115,841**

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (DEFICIT)
For the years ended December 31, 2021 and 2020

Year ended December 31, 2021 *(thousands of Canadian dollars)*	**Common Shares**	**Deficit**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity (Deficit)**
January 1, 2021	5,000	(4,651)	(461)	(112)
Net loss	—	—	—	—
Other comprehensive income	—	—	19	19
December 31, 2021	**5,000**	**(4,651)**	**(442)**	**(93)**

Year ended December 31, 2020 *(thousands of Canadian dollars)*	**Common Shares**	**Income (Deficit)**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity (Deficit)**
January 1, 2020	5,000	(4,651)	(479)	(130)
Net loss	—	—	—	—
Other comprehensive income	—	—	18	18
December 31, 2020	**5,000**	**(4,651)**	**(461)**	**(112)**

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2021 and 2020

Year ended December 31 *(thousands of Canadian dollars)*	**2021**	**2020**
Operating activities		
Net loss	—	—
Environmental expenditures	(1,435)	(870)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	4,493	3,704
Regulatory assets and liabilities	(3,969)	312
Other	29	27
Changes in non-cash balances related to operations *(Note 17)*	9,218	(5,650)
Net cash from (used in) operating activities	**8,336**	**(2,477)**
Investing activities		
Capital expenditures	(6,339)	(3,013)
Future use assets	585	(993)
Net cash used in investing activities	**(5,754)**	**(4,006)**
Net change in inter-company demand facility	2,582	(6,483)
Inter-company demand facility, beginning of year	(42)	6,441
Inter-company demand facility, end of year	**2,540**	**(42)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One Inc. (Hydro One), which is wholly owned by Hydro One Limited. Hydro One Remote Communities generates and distributes electricity to customers in 21 off grid communities in northern Ontario and distributes to one community connected to the Province's electricity grid. The Company's business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On November 3, 2020, Hydro One Remote Communities filed an application with the OEB seeking approval for an increase to 2020 base rates of 2.0%, which was subsequently updated to 2.2% on January 11, 2021, effective May 1, 2021. On March 1, 2021, the OEB issued a draft decision approving the requested increase, which was later finalized on March 25, 2021. On November 3, 2021, Hydro One Remote Communities filed an application with the OEB seeking approval for an increase to 2021 base rates of 2.2%, which was subsequently updated to 3.3% on January 4, 2022, effective May 1, 2022. On March 24, 2022, the OEB approved the 3.3% rate increase.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. The Company uses a cost recovery model applied to achieve breakeven net income and the Financial Statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2021 have been prepared and are publicly available.

Hydro One Remote Communities performed an evaluation of subsequent events through to April 27, 2022, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, contingencies, and unbilled revenues. Actual results may differ significantly from these estimates.

Since late March 2020, the impact of COVID-19 has been reflected in the Company's financial statements. The Company has analyzed the impact of the pandemic on its estimates and assumptions that affect its financial results as at and for the year ended December 31, 2021 and has determined that there was no material impact.

As the duration of the pandemic remains uncertain, the Company continues to assess its impact to the Company's financial results and operations.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a subsequent event adjustment.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes. Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the RRRP variance account. The balance in the RRRP variance account is subject to future review and disposition by the OEB.

Revenue Recognition

Revenues attributable to the generation and delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, volume of electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses (CECL) for all accounts receivable balances. The Company estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Long-term accounts receivable are recorded at their invoiced amount, net of allowance for doubtful accounts and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. The CECL for this component is set at the inception of the balance and is maintained until settlement of those amounts. The CECL for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.

Income Taxes

Income taxes are accounted for using the asset and liability method. Current tax assets and liabilities are recognized based on the taxes payable or refundable on the current and prior year's taxable income. Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date.

Deferred income taxes associated with its regulated operations which are considered to be more-likely-than-not to be recoverable or refunded in the future regulated rates charged to customers are recognized as deferred income tax regulatory assets and liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the balance sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and information technology. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

<u>Generation</u>

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

<u>Distribution</u>

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices, and metering systems.

<u>Administration and Service</u>

Administration and service assets include administrative buildings, personal computers, tools, and other minor assets.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the statements of operations and comprehensive income (loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction in Progress

Construction in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2013.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Generation	20	3% - 7%	5 %
Distribution	44	1% - 7%	2 %
Administration and service	38	3% - 20%	3 %

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, that are normally retired, is charged to accumulated depreciation with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of Hydro One Remote Communities' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2021 and 2020, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts net of related debt on the balance sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the statements of operations and comprehensive income (loss). Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents net income and OCI in a single continuous statement of operations and comprehensive income (loss).

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories (i) held-to-maturity, (ii) loans and receivables, (iii) held-for-trading, (iv) other liabilities, or (v) available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at its net realizable value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. The Company estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible.

The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in note 11 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2021 and 2020. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and post-employment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.

Defined Benefit Pension

Hydro One has a contributory Pension Plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution pension plan and no pension benefit asset or liability is recorded.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in accumulated OCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment for the service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Society Restricted Share Unit (RSU) Plan

The Company measures its Society RSU plan based on fair value of share grants as estimated based on Hydro One Limited's grant date common share price. The costs are recognized over the vesting period using the straight-line attribution method. The Company records a regulatory asset equal to the accrued costs of the Society RSU plan recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One Remote Communities records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) based on the undiscounted value of these estimated future expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed. Estimate changes are accounted for prospectively.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standard Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One Remote Communities:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact
ASU 2019-12	December 2019	The amendments simplify the accounting for income taxes by removing certain exceptions to the general principles and improving consistent application of Topic 740 by clarifying and amending existing guidance.	January 1, 2021	No impact upon adoption
ASU 2020-01	January 2020	The amendments clarify the interaction of the accounting for equity securities under Topic 321, investments under the equity method of accounting in Topic 323 and the accounting for certain forward contracts and purchased options accounted for under Topic 815.	January 1, 2021	No impact upon adoption
ASU 2020-10	October 2020	The amendments are intended to improve the Codification by ensuring the guidance required for an entity to disclose information in the notes of financial statements are codified in the disclosure sections to reduce the likelihood of disclosure requirements being missed.	January 1, 2021	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact
ASU 2020-06	August 2020	The update addresses the complexity associated with applying GAAP for certain financial instruments with characteristics of liabilities and equity. The amendments reduce the number of accounting models for convertible debt instruments and convertible preferred stock.	January 1 2022	No impact upon adoption
ASU 2021-05	July 2021	The amendments are intended to align lease classification requirements for lessors under Topic 842 with Topic 840's practice.	January 1, 2022	No impact upon adoption
ASU 2021-08	October 2021	The amendments address how to determine whether a contract liability is recognized by the acquirer in a business combination.	January 1, 2023	Under assessment
ASU 2021-10	November 2021	The update addresses the diversity on the recognition, measurement, presentation and disclosure of government assistance received by business entities.	January 1, 2022	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(thousands of dollars)*	2021	2020
Depreciation of property, plant and equipment	3,058	2,834
Amortization of regulatory assets	1,435	870
Depreciation and amortization	4,493	3,704
Asset removal costs	342	361
	4,835	4,065

5. FINANCING CHARGES

Year ended December 31 *(thousands of dollars)*	2021	2020
Interest on long-term debt	1,958	1,958
Amortization of hedging losses	19	18
Other	12	33
Interest capitalized on construction in progress	(219)	(173)
Interest income on inter-company demand facility	(6)	(23)
	1,764	1,813

6. INCOME TAXES

As a rate regulated utility company, the Company recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated business. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred income tax expense (recovery). The Company's tax expense or recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable or refunded in future rates charged to customers. Thus, the Company's income tax expense or recovery differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate.

The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(thousands of dollars)*	2021	2020
Loss before income tax expense	—	(3)
Income tax expense at statutory rate of 26.5% (2020 - 26.5%)	—	(1)
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Non-capital losses	1,020	(225)
Depreciation and amortization in excess of capital cost allowance	404	271
Post-retirement and post-employment benefit expense in excess of cash payments	—	273
RRRP variance account	(1,063)	116
Environmental expenditures	(380)	(231)
Overheads capitalized for accounting but deducted for tax purposes	(152)	(152)
Pension contribution in excess of pension expense	174	(60)
Interest capitalized for accounting but deducted for tax purposes	(58)	(46)
Change in valuation allowance	—	—
Other	51	14
Net temporary differences	(4)	(40)
Prior year adjustments	—	8
Other permanent differences	4	30
Total income tax expense (recovery)	—	(3)

The major components of income tax expense (recovery) are as follows:

Year ended December 31 *(thousands of dollars)*	2021	2020
Current income tax expense (recovery)	—	(3)
Deferred income tax expense	—	—
Total income tax expense (recovery)	—	(3)
Effective income tax rate	— %	100.0 %

The following table presents a reconciliation of net income (loss) to net income under the cost recovery model:

Year ended December 31 *(thousands of dollars)*	2021	2020
Net loss before income tax expense	—	(3)
Income tax recovery under cost-recovery model	—	(3)
Net income under cost-recovery model	—	—
Income tax expense	—	—
Net loss	—	—

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities reflect the future tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and liabilities attributable to the Company's regulated business are recognized with a corresponding offset in deferred income tax regulatory assets and liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. At December 31, 2021 and 2020, deferred income tax assets and liabilities consisted of the following:

As at December 31 *(thousands of dollars)*	2021	2020
Deferred income tax assets (liabilities)		
Environmental expenditures	15,572	15,640
Depreciation and amortization in excess of capital cost allowance	2,685	3,448
Post-retirement and post-employment benefits expense in excess of cash payments	6,631	6,623
Regulatory amounts not recognized for tax	(18,908)	(17,895)
Other	4,172	2,370
	10,152	10,186
Less: valuation allowance	(5,723)	(5,693)
Net deferred income tax assets	4,429	4,493

During 2021 and 2020, there was no change in the rate applicable to deferred tax assets and liabilities. The valuation allowance for deferred tax assets as at December 31, 2021 was $5,723 thousand (2020 - $5,693 thousand). The valuation allowance primarily relates to temporary differences for non-depreciable assets and loss carryforwards. As at December 31, 2021, the Company had non-capital losses of $14,126 thousand, which will begin to expire in 2036.

7. ACCOUNTS RECEIVABLE

As at December 31, 2021 *(thousands of dollars)*	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable – billed	5,026	6	5,032
Accounts receivable – unbilled	3,937	—	3,937
Accounts receivable, gross	8,963	6	8,969
Allowance for doubtful accounts	(128)	—	(128)
Accounts receivable, net	8,835	6	8,841

As at December 31, 2020 *(thousands of dollars)*	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable – billed	6,179	49	6,228
Accounts receivable – unbilled	2,920	—	2,920
Accounts receivable, gross	9,099	49	9,148
Allowance for doubtful accounts	(324)	—	(324)
Accounts receivable, net	8,775	49	8,824

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2021 and 2020:

Year ended December 31 *(thousands of dollars)*	2021	2020
Allowance for doubtful accounts - beginning	(324)	(119)
Write-offs	62	98
Adjustments to allowance for doubtful accounts	134	(303)
Allowance for doubtful accounts - ending	(128)	(324)

8. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2021 *(thousands of dollars)*	Property, Plant and Equipment [1]	Accumulated Depreciation	Construction in Progress	Total
Generation	53,474	24,531	1,979	30,922
Distribution	13,182	3,124	831	10,889
Administration and service	13,221	3,915	679	9,985
	79,877	31,570	3,489	51,796

[1] Includes future use assets totalling $3,909 thousand.

As at December 31, 2020 *(thousands of dollars)*	Property, Plant and Equipment [1]	Accumulated Depreciation	Construction in Progress	Total
Generation	51,077	23,445	2,842	30,474
Distribution	12,315	2,908	813	10,220
Administration and service	12,743	3,652	31	9,122
	76,135	30,005	3,686	49,816

[1] Includes future use assets totalling $4,534 thousand.

Financing charges capitalized on property, plant and equipment under construction were $219 thousand in 2021 (2020 - $173 thousand).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

As at December 31 *(thousands of dollars)*	2021	2020
Regulatory assets:		
Environmental	43,191	43,378
RRRP variance account	9,732	5,598
Stock-based compensation	432	467
Post-retirement and post-employment benefits	—	569
COVID-19 emergency deferral	—	120
Total regulatory assets	53,355	50,132
Less: current portion	(3,172)	(3,087)
	50,183	47,045
Regulatory liabilities:		
Deferred income tax regulatory liability	4,429	4,493
Post-retirement and post-employment benefits	481	—
COVID-19 emergency deferral	10	—
Total regulatory liabilities	4,920	4,493

Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized because management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. The Company has recorded an equivalent amount as a regulatory asset. In 2021, the revaluation adjustment increased the environmental regulatory asset by $1,248 thousand (2020 - $10,153 thousand) to reflect related changes in the Company's environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2021 OM&A expenses would have been higher by $1,248 thousand (2020 - $10,153 thousand), and 2021 amortization expense would have been lower by $1,435 thousand (2020 - $870 thousand).

RRRP Variance Account

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2021, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of cumulative RRRP amounts received. In 2021, RRRP amounts received were lower (2020 - higher) than amounts required to achieve breakeven net income, and as such, the regulatory asset was increased by $4,134 thousand (2020 -$491 thousand). In the absence of rate-regulated accounting, 2021 revenue would have been lower by $4,134 thousand (2020 - higher by $491 thousand).

Stock-Based Compensation

The Company recognizes costs associated with share grant plans and Society RSUs in a regulatory asset as management considers it probable that share grant plans' and Society RSU costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, there would be no material impact to operation, maintenance and administration expenses in 2021 and 2020. Share grant and Society RSU costs are transferred to labour costs at the time they vest and are issued, and are recovered in rates in accordance with recovery of these labour costs.

Deferred Income Tax Regulatory Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized a regulatory liability that corresponds to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2021 income tax expense would have been higher by approximately $4 thousand (2020 - $40 thousand).

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the balance sheets with an incremental offset to the associated regulatory asset or regulatory liability, as the case may be. A regulatory asset or liability is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered or returned in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2021 OCI would have been higher by $1,050 thousand (2020 - $301 thousand).

COVID-19 Emergency Deferral

On June 17, 2021, the OEB issued its Report: Regulatory Treatment of Impact Arising from the COVID-19 Emergency which outlines the OEB's final guidance on the rules and operation of the deferral account established for utilities to track the impacts arising from the COVID-19 pandemic. The OEB has determined that eligibility for recovery of most balances recorded in the account will be subject to a means test based on a utility's achieved regulatory return on equity (ROE). Based on management's assessment of the OEB's final guidance, no amounts related to the COVID-19 pandemic have been recognized as regulatory assets. The December 31, 2021 balance relates to over-recovered foregone revenues collected from ratepayers over the period from November 1, 2020 to April 30, 2021.

10. LONG-TERM DEBT

Long-term debt represents inter-company debt issued to Hydro One. The following table presents the Company's outstanding long-term debt at December 31, 2021 and 2020:

As at December 31 *(thousands of dollars)*	2021	2020
3.02% note due 2026	10,000	10,000
5.38% note due 2036	23,000	23,000
4.19% note due 2044	10,000	10,000
	43,000	43,000
Less: Deferred debt issuance costs	(142)	(150)
Less: Net unamortized debt premiums	(31)	(33)
Long-term debt	42,827	42,817

The Company did not issue or repay any long-term debt in 2021 and 2020.

Principal and Interest Payments

At December 31, 2021, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

Years	Long-Term Debt Principal Repayments *(thousands of dollars)*	Interest Payments *(thousands of dollars)*	Weighted-Average Interest Rate *(%)*
2022	—	1,958	—
2023	—	1,958	—
2024	—	1,958	—
2025	—	1,958	—
2026	—	1,809	—
	—	9,641	—
2027-2030	10,000	8,282	3.0
2031+	33,000	10,806	5.0
	43,000	28,729	4.6

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One Remote Communities classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Remote Communities has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2021 and 2020, the Company's carrying amounts of inter-company demand facility, accounts receivable, and accounts payable are representative of fair value due to the short-term nature of these instruments.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2021 and 2020 is as follows:

As at December 31, 2021 *(thousands of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt	42,827	52,123	—	52,123	—

As at December 31, 2020 *(thousands of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt	42,817	55,701	—	55,701	—

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2021 or 2020.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

<u>Market Risk</u>

Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

<u>Credit Risk</u>

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2021 and 2020, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One Remote Communities did not earn a material amount of revenue from any single customer. At December 31, 2021 and 2020, there was no material accounts receivable balance due from any single customer.

At December 31, 2021, the Company's allowance for doubtful accounts was $128 thousand (2020 - $324 thousand). The allowance for doubtful accounts reflects the Company's CECL for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. At December 31, 2021, approximately 14% (2020 - 28%) of the Company's net accounts receivable were outstanding for more than 60 days. The Company's credit risk for accounts receivable is limited to the carrying amounts on its balance sheets.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company are expected to be sufficient to fund normal operating requirements.

12. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a DC Plan, a supplementary pension plan (Supplementary Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplementary DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the Income Tax Act (Canada) in the form of credits to a notional account. Company contributions to the DC Plan for the year ended December 31, 2021 were $11 thousand (2020 - $10 thousand).

Pension Plan and Supplementary Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The new valuation is expected to be filed by no later than effective September 30, 2022, which may result in a change to the estimated contributions for 2022-2027. Total Hydro One annual cash Pension Plan employer contributions for the Company in 2021 were $723 thousand (2020 - $711 thousand). Estimated Hydro One annual Pension Plan employer contributions allocated to the Company for the years 2022, 2023, 2024, 2025, 2026 and 2027 are approximately $1,053 thousand, $1,110 thousand, $1,156 thousand, $1,163 thousand, $1,190 thousand and $1,240 thousand respectively.

The Supplementary Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the *Income Tax Act* (Canada).

At December 31, 2021, the present value of Hydro One's projected pension benefit obligation was estimated to be $9,358 million (2020 - $9,763 million). The fair value of pension plan assets available for these benefits was $8,645 million (2020 - $8,103 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2021, Hydro One Remote Communities charged $873 thousand (2020 - $1,098 thousand) of post-retirement and post-employment benefit costs to operation, maintenances and administration expenses, and capitalized $456 thousand (2020 - $512 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2021 were $258 thousand (2020 - $272 thousand). In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $1,050 thousand (2020 - increase of $301 thousand) was recorded on the Company's balance sheet to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the balance sheets within the following line items:

As at December 31 (thousands of dollars)	**2021**	**2020**
Accrued liabilities	509	473
Post-retirement and post-employment benefit liability	17,882	17,898
	18,391	18,371

13. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the years ended December 31, 2021 and 2020:

Year ended December 31 *(thousands of dollars)*	**2021**	**2020**
Environmental liabilities - beginning	43,378	34,095
Expenditures	(1,435)	(870)
Revaluation adjustment	1,248	10,153
Environmental liabilities - ending	43,191	43,378
Less: current portion	(3,064)	(2,863)
	40,127	40,515

The environmental liabilities are not discounted as the amount and timing of cash payments for the liabilities are not fixed or reliably determinable.

At December 31, 2021, the estimated future environmental expenditures were as follows:

(thousands of dollars)	
2022	3,064
2023	1,941
2024	2,510
2025	2,651
2026	1,144
Thereafter	31,881
	43,191

The Company records a liability for the estimated future expenditures for LAR when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs, which is its undiscounted amount, required to meet existing legislation or regulations.

As at December 31, 2021, the Company's best estimate of the total estimated future expenditures to complete its LAR program was $43,191 thousand (2020 - $43,378 thousand). These expenditures are expected to be incurred over the period from 2021 to 2054. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2021 to increase the LAR environmental liability by $1,248 thousand (2020 - $10,153 thousand).

14. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2021, the Company had 267 common shares issued and outstanding (2020 - 267).

Dividends

The Company does not pay dividends under its breakeven business model.

15. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Remote Communities, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees of Hydro One Remote Communities.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore, the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Remote Communities of $1,091 thousand was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2021, 5,279 common shares of Hydro One Limited were issued under the Share Grant Plans (2020 - 5,387) to eligible employees of Hydro One Remote Communities. Total share based compensation recognized by Hydro One Remote Communities during 2021 was $63 thousand (2020 - $115 thousand) and was recorded as a regulatory asset.

A summary of Hydro One Remote Communities' share grant activity under the Share Grant Plans during years ended December 31, 2021 and 2020 is presented below:

Year ended December 31, 2021	Share Grants (Number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	34,984	$20.50
Vested and issued[1]	(5,279)	—
Transfers[2]	2,614	—
Forfeited	(1,897)	$20.50
Share grants outstanding - ending	30,422	$20.50

[1] In 2021, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

[2] Transfers relate to PWU employees transferred from Hydro One Networks to Hydro One Remote Communities during 2021. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

Year ended December 31, 2020	Share Grants (Number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	38,328	$20.50
Vested and issued[1]	(5,387)	—
Transfers[2]	2,865	—
Forfeited	(822)	$20.50
Share grants outstanding - ending	34,984	$20.50

[1] In 2020, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

[2] Transfers relate to PWU employees transferred from Hydro One Networks to Hydro One Remote Communities during 2020. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2021, Company contributions made under the ESOP were $24 thousand (2020 - $22 thousand).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

During 2021 and 2020, the activity of PSU and RSU awards granted by Hydro One Limited that related to Hydro One Remote Communities were as follows:

Year ended December 31 *(number of units)*	**PSUs 2021**	**PSUs 2020**	**RSUs 2021**	**RSUs 2020**
Units outstanding – beginning	3,284	6,065	2,319	2,377
Vested and issued[1]	(3,284)	(2,711)	(2,319)	(12)
Forfeited	—	(70)	—	(46)
Units outstanding – ending	—	3,284	—	2,319

[1] In 2021, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the LTIP. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

No awards were granted in 2021 or 2020. The compensation expense related to the PSU and RSU awards recognized by the Company during 2021 was $10 thousand (2020 - $100 thousand).

Society RSU Plan

As a result of the renewal of the Company's prior collective agreement with members of the Society, the Company provided equity compensation in the form of RSUs to certain eligible members. The equity compensation provides for the purchase of common shares of Hydro One Limited from the open market, effective March 1, 2021 in one equity grant vesting in equal portions over a two-year period. To be eligible, an employee must be an employee of the Company as of July 30, 2021, the date the plan was ratified by the Society; the grant date. The number of common shares issued to each eligible employee will be equal to 1.0% of such eligible employee's salary as at April 1, 2021, divided by $30.80, being the price of the common shares of Hydro One Limited at the grant date. Each RSU is entitled to accrue common share dividend equivalents in the form of additional RSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

A summary of RSU awards activity under the Society RSU Plan during the years ended December 31, 2021 and 2020 is presented below:

Year ended December 31 *(number of RSUs)*	**2021**	**2020**
RSUs outstanding - beginning	—	—
Granted	654	—
RSUs outstanding - ending	654	—

16. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.2% ownership at December 31, 2021. The IESO is a related party to Hydro One Remote Communities because it is controlled or significantly influenced by the Ministry of Energy.

Year ended December 31 *(thousands of dollars)*

Related Party	**Transaction**	**2021**	**2020**
IESO	Supply of electricity to remote northern communities - amounts received[1]	35,223	35,223
	Amounts related to electricity rebates	5,060	7,735
Hydro One Networks Inc.	Revenues related to the provision of services[2]	236	160
	Cost of power	1,485	1,665
	Costs expensed related to purchase of services[2]	2,848	3,158
Hydro One Inc.	Interest income on inter-company demand facility	6	23
	Interest expense on long-term debt	1,958	1,958
	Costs expensed related to purchase of services[2]	55	23
	Stock-based compensation costs	82	215

[1] Consistent with the break even business model, the Company recognized $39,357 thousand as RRRP revenue in 2021 (2020 - $34,732), with the difference recorded in the regulatory asset RRRP variance account.
[2] The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services.

Transactions with related parties are based on the requirements of the OEB's Affiliate Relationships Code.

The amounts due to and from related parties are as follows:

As at December 31 *(thousands of dollars)*	**2021**	**2020**
Inter-company demand facility	2,540	(42)
Accounts receivable	470	767
Accrued interest	280	280
Long-term debt	42,969	42,967

17. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(thousands of dollars)*	**2021**	**2020**
Accounts receivable	(60)	(1,337)
Fuel, materials and supplies	(705)	498
Income taxes receivable	2	5
Long-term accounts receivable	43	73
Accounts payable	5,424	(6,120)
Accrued liabilities	3,476	(184)
Long-term accounts payable	4	82
Post-retirement and post-employment benefit liability	1,034	1,333
	9,218	(5,650)

Supplementary Information

Year ended December 31 *(thousands of dollars)*	**2021**	**2020**
Net interest paid	1,958	1,958

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid are fully recovered.

18. CONTINGENCIES

Legal Proceedings

Hydro One Remote Communities is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Hydro One Remote Communities is a defendant in a lawsuit in which the plaintiff Wilderness North Air is seeking $16 million in damages related to allegations of breach of contract following a competitive request for proposals for the supply of diesel fuel. Hydro One Remote Communities is defending itself in the claim and has determined there is a reasonable possibility of liability to the Company, and if liability is found, the estimated range of losses is between $50 thousand to $400 thousand.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the Ontario Electricity Financial Corporation (OEFC) holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2021, Hydro One paid approximately $2 million (2020 - $2 million) in respect of consents obtained. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

19. COMMITMENTS

Operating Agreement

Hydro One Remote Communities is committed to an operating agreement related to a hydro facility owned by the Company to pay annual performance payments for a period of 10 years. The operating agreement expires in 2022. During the year ended December 31, 2021, the Company made payments totalling $150 thousand (2020 - $150 thousand). The following table presents a summary of Hydro One Remote Communities' commitments under this agreement.

December 31, 2021 *(thousands of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Operating agreement	150	—	—	—	—	—

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31, 2021 *(thousands of Canadian dollars)*	**Audited Financial Statements**	**Non-Regulated Segment**	**Regulated Segment**
Revenues	63,271	—	63,271
Costs			
Operation, maintenance and administration	20,607	—	20,607
Cost of power	1,584	—	1,584
Fuel used for electric generation	34,481	—	34,481
Depreciation, amortization and asset removal costs	4,835	—	4,835
Gain on disposition of assets	—		—
	61,507	—	61,507
Income before financing charges and income tax expense	**1,764**	**—**	**1,764**
Financing charges	1,764	—	1,764
Loss before income tax expense	**—**	**—**	**—**
Income tax recovery	—	— A	—
Net loss	**—**	**—**	**—**
Other comprehensive income	19	—	19
Comprehensive income	**19**	**—**	**19**

Notes:

A - There was no net tax expense movement in the year arising from within the Company's non-regulated segment.

hydro One

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS

December 31, 2021 *(thousands of Canadian dollars)*	**Audited Financial Statements**	**Non-Regulated Segment**		**Regulated Segment**
Assets				
Current assets:				
Inter-company demand facility	2,540	—		2,540
Accounts receivable	8,835	—		8,835
Regulatory assets	3,172	—		3,172
Fuel, materials and supplies	3,240	—		3,240
Income taxes receivable	18	1,031	A	—
		(1,013)	D	
	17,805	18		17,787
Property, plant and equipment	51,796	—		51,796
Other long-term assets:				
Regulatory assets	50,183	—		50,183
Deferred income tax assets	4,429	—		4,429
Long-term accounts receivable	6	—		6
Other assets	14	—		14
	54,632	—		54,632
Total assets	**124,233**	**18**		**124,215**
Liabilities				
Current liabilities:				
Inter-company demand facility	—	(1,013)	D	1,013
Accounts payable	6,873	—		6,873
Accrued liabilities	11,317	—		11,317
Accrued interest	280	—		280
	18,470	(1,013)		19,483
Long-term liabilities:				
Accounts payable	86	—		86
Long-term debt	42,827	—		42,827
Post-retirement and post-employment benefit liability	17,882	—		17,882
Regulatory liabilities	4,920	—		4,920
Environmental liabilities	40,127	—		40,127
Other liabilities	14	—		14
	105,856	—		105,856
Total liabilities	**124,326**	**(1,013)**		**125,339**
Shareholder's equity (deficit)				
Common shares	5,000	5,000	B	—
Deficit	(4,651)	(3,969)	C	(682)
Accumulated other comprehensive loss	(442)	—		(442)
Total shareholder's equity (deficit)	**(93)**	**1,031**		**(1,124)**
Total liabilities and shareholder's equity (deficit)	**124,233**	**18**		**124,215**

Notes:

A - Cumulative tax benefit relating to utilization of the non-regulated Deferred Tax Asset

B - Injection of equity by Shareholder (Hydro One Inc.) to fund Departure Tax in 2015

C - Cumulative effect from 2015 of Departure Tax expense and tax recovery relating to utilization of the non-regulated Deferred Tax Asset

D - Reclassification of credit balance to inter-company demand facility subsequent to adjustment A

2021 FINANCIAL STATEMENTS RECONCILED TO USOFA TRIAL BALANCE

This exhibit has been filed separately in MS Excel format.

DISTRIBUTOR CONSOLIDATION

Remotes has not, nor expects to, participate in any regulated distributor consolidation activities over the term of this application. Remotes is a small distributor for isolated communities, and thus opportunities for consolidation or collaboration/partnerships with other rate regulated distributors in Ontario are limited, and no investigations or studies regarding consolidation have been performed.

With respect to working with other utilities, Remotes will continue to leverage the Canadian Off-Grid Utility Association (COGUA) regarding potential collaboration and partnerships, as it most accurately represents the Remotes peer group. COGUA, which represents off-grid utilities, often has working groups, studies, and initiatives related to joint topics of interest. Remotes will consider collaboration and partnerships if these have the potential to be of benefit to its customers. Remotes also continues to leverage services from Networks under the Affiliate Relationship Code (ARC). This collaboration ensures that as a small business, Remotes can access highly specialized support necessary for its business operations. Shared Services and Corporate cost allocation is further described in Exhibit D, Tab 1, Schedule 8.

Remotes is anticipating the addition of seven new unregulated communities that are expected to join Remotes' service area over the forecast period: Cat Lake (2023), Muskrat Dam (2023), Wawakepewin (2023), Wunnumin Lake (2023), Keewaywin (2024), North Spirit (2024), and Poplar Hill (2024). The six Independent Power Authority (IPA) communities (all excluding Cat Lake) are expected to connect to the Watay Project. Pursuant to section 4.0.4 of O. Reg. 161/99, the addition of these communities is exempted from the requirements of section 86 of the *Ontario Energy Board Act, 1998*. Nonetheless, Remotes is actively working with the communities and its stakeholders on an orderly transition for the IPA communities to be served by Remotes.

This page has been left blank intentionally.

IMPACT OF COVID-19

1.0 INTRODUCTION

Like other organizations and businesses, COVID-19 has drastically changed the way we work, as well as the work we do. During this period, Remotes has continued to focus on two fundamental priorities: protecting our employees and maintaining the safe and reliable supply of electricity. COVID-19 continues to challenge operations; however, protocols and processes are in place and continually evaluated to protect Remotes' staff and the communities it serves.

The majority of the Remotes' focus on safety in the past few years has been related to the development and implementation of enhanced COVID-19 protocols to ensure it can maintain operations while minimizing risk to employees and others. Remotes has been leveraging the work of Networks, relying on the expertise of local health boards, and continuing to follow provincial cues. COVID-19 issues unique to Remotes includes air transportation as well as small crews living and working together in an isolated remote community.

Significant efforts have been made to continually engage the leadership of the communities we serve to ensure essential work can be accomplished in the current environment. Given our communities face increased risk compared to larger communities with access to modern and more robust health care facilities and services, Remotes has been very cautious and sensitive when planning and executing its work programs. Remotes has sought to understand the specific concerns of individual communities and their COVID-19 protocols and has engaged with the communities using multiple communication channels, explaining the focus on essential work and COVID-19 precautionary practices. These efforts have been well received by community leadership.

To date, COVID-19 has impacted Remotes in various ways including delayed revenue for energy, reduced late payment charges, increased safety supplies, testing costs and additional labour stand down costs. Projects and programs have been most impacted. To maintain focus on its priorities, essential and critical work has continued often at a higher logistical cost or with added complexity. Non-essential work has been delayed, deferred or cancelled but not to an extent that will impact the ability to provide safe reliable power to customers. OEB public policy decisions such as the deferral of disconnections or suspension of late payment fees have also impacted Remotes.

The pandemic has also restricted Remotes' ability to actively manage (in-person) its complex relationships with stakeholders; or be a community presence when needed for activities such as operator training or community program promotion sessions. Given their high levels of complexity, joint ISC-First Nation-Remotes upgrade projects were impacted or delayed. For the benefit of helping customers during this difficult time, Remotes agreed to defer planned rate increases and make up the lost summer revenue by introducing slightly higher rates through a rate rider, Exhibit H, Tab 1, Schedule 1 and Exhibit G, Tab 1, Schedule 1. There were periods of transitional work costs, as well as increased sick-time or downtime. Some materials have been negatively impacted by widespread supply chain challenges affecting availability and cost of materials.

COVID-19 pandemic infections are now very low in Ontario and all business restrictions have been lifted and normalcy in most activities for our service territory is expected to be in full swing by the fall. High vaccination rate continues to help in the continuing decline of COVID-19. Like many, Remotes is confident the worst is behind it and looks forward to more actively managing its assets and providing the full service experience its customers deserve.

Since late March 2020, the impact of COVID-19 has been reflected in the Remotes' financial statements. Remotes has analyzed the impact of the pandemic on its estimates and assumptions that affect its financial results as at and for the year ended December 31, 2021 and has determined that there was no material impact. As the duration of the pandemic remains uncertain, Remotes continues to assess the impacts to its financial results and operations.

On June 17, 2021, the OEB issued its Report: Regulatory Treatment of Impact Arising from the COVID-19 Emergency[1] which outlines the OEB's final guidance on the rules and operation of the deferral account established for utilities to track the impacts arising from the COVID-19 pandemic. The OEB has determined that eligibility for recovery of most balances recorded in the account will be subject to a means test based on a utility's achieved regulatory return on equity (ROE). Based on Remotes' assessment of the OEB's final guidance, no amounts related to the COVID-19 pandemic have been recognized as regulatory assets since Remotes does not have an approved ROE and operates on a break-even basis. Any incremental costs are expected to flow through the RRRP account. Remotes continues to make significant efforts to frequently engage the leadership of the communities it serves to ensure that work can be accomplished.

In this application, Remotes is requesting a one-time disposition in 2023, to clear the residual credit balance of $10k, in the Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation (see Exhibit G, Tab 1, Schedule 1). There are no other outstanding COVID-19 regulatory balance variances in which Remotes is requesting recovery.

[1] EB-2020-0133 – Impacts Arising from the COVID-19 Emergency

This page has been left blank intentionally.

COMPLIANCE WITH LICENCE AND OEB FILING REQUIREMENTS FOR ELECTRICITY DISTRIBUTORS

1.0 INTRODUCTION

This Application by Remotes is substantially consistent with the requirements of the 2016 Electricity Distribution Rate Handbook (the Handbook) issued by the OEB on October 13, 2016, and with the 2023 Filing Requirements for Distribution Rate Applications (the Filing Requirements) issued by the OEB on April 18, 2022.

Remotes' Application satisfies the Filing Requirements and the Handbook except where it was not practical or appropriate to do so based on previous comments and direction from the Board, or as a result of specific government regulation as noted in the following sections of this exhibit. Where the OEB's Workforms were used, Remotes has filed the data in live Microsoft Excel format and ensured that the data reconciles between the models.

Remotes did not have any specific directions from the OEB, nor from the 2018 settlement agreement, in the last distribution rate proceeding in EB-2017-0051.

1.1 COMPLIANCE WITH LICENCE

EXEMPTIONS FROM THE ELECTRICITY ACT, 1998

Remotes is exempt from the following sections of the *Electricity Act, 1998*:

- Subsection 26(1), non-discriminatory access
- Subsection 26(3), to the extent that a contract entered into by Ontario Hydro contains liabilities, rights or obligations that have been transferred to Remotes
- Section 28, distributor's obligation to connect.

EXEMPTIONS FROM THE ONTARIO ENERGY BOARD ACT, 1998

Remotes is exempt from the following sections of the *Ontario Energy Board Act, 1998*:

- Section 70(2)(e), specifying methods or techniques to be applied in determining the licensee's rates
- Section 71, restriction on business activity
- Section 80, prohibition, generation by transmitters or distributors
- Section 81, prohibition, transmission or distribution by generators

None of Remotes' customers is prescribed under Sections 79.16 under the *Ontario Energy Board Act, 1998*.

EXEMPTIONS FROM LICENCE CONDITIONS

Remotes is exempt from the entire Standard Supply Service Code and the entire Retail Settlement Code, and from various sections of the Distribution System Code per Schedule 3 of its Distribution Licence ED-2003-0037 filed at Exhibit A, Tab 2, Schedule 1, Attachment 1; Remotes' Generation Licence EG-2003-0138 is filed at Exhibit A, Tab 2, Schedule 1, Attachment 2.

CONSERVATION & DEMAND MANAGEMENT FOR ELECTRICITY DISTRIBUTORS

Remotes has not been subject to the Conservation & Demand Management Code for Electricity Distributors and has not been assigned targets under that Code. The 2021 CDM Guidelines provide utilities with additional guidance on the role of conservation and demand management for rate regulated electricity distributors.

2.0 COMPLIANCE WITH LICENCE AND OEB FILING REQUIREMENTS

Most of Remotes' customers are eligible for Remote Rate Protection under Section 79 of the *Ontario Energy Board Act, 1998*. This legislation requires that Remotes charge rates that are not based on the cost of service. In view of this legislative requirement, Remotes did not undertake a cost allocation study as required by Board guidelines prior to filing this Application. A cost allocation study requires substantial effort and would have provided no benefit, as customers cannot be charged the cost of supplying power to them without changes to the legislation.

Remotes provides both generation and distribution services outside of the competitive market. Its rates and revenue requirement include both cost categories. Accordingly, information on all of Remotes' activities is included to ensure that generation and distribution costs can be examined in this proceeding.

The filing requirements indicate that a forward test-year methodology is to be utilized when a distributor is seeking the Board's approval for rebasing its rates. Remotes' Application has been filed using a forward test year and provides four years of historical data. As such, this Application includes written evidence and supporting schedules for the following:

- 2023 test year;
- 2022 bridge year;
- 2018, 2019, 2020 and 2021 historical years; and
- 2018 Board-approved historical year.

Remotes has filed its 2023 Cost of Service Checklist as Exhibit A, Tab 2, Schedule 1, Attachment 3.

BENCHMARKING AND ACTIVITY AND PERFORMANCE-BASED (APB) BENCHMARKING

Remotes has not provided a PEG Benchmarking Exhibit in this filing. Remotes is an integrated generation company with unique financing and operations. The Board has previously recognized that Remotes is not directly comparable to other Ontario distributors. In its Decision in proceeding EB-2014-0084, the Board noted that, "Hydro One Remotes is excluded from the Board's benchmarking analysis because of its unique circumstances. As noted in Hydro One Remotes' 2014 Price Cap Incentive Rate application (EB-2013-0142), Hydro One Remotes is unique in terms of its operating characteristics and cost recovery due to the Rural or Remote Electricity Rate Protection." The OEB has continued to accept this explanation in rate proceedings, up to and including, the most recent 2022 IRM application (EB-2021-0034) as the basis for excluding Hydro

One Remotes from benchmarking analysis in the determination of a stretch factor for its annual price adjustment factor. For these same reasons, Remotes has also not provided any evidence in this application regarding the most recent Activity and Performance-based Benchmarking (APB) results and Remotes is not identified as a stand-alone distributor in the APB report.[1]

EXEMPTION FROM USE OF ACCOUNT 1592

Remotes is exempt from the OEB's Capital Cost Allowance (CCA) and Tax Related Accounting Direction, specifically related to the accelerated investment incentive (AII) program[2] as filed at Exhibit A, Tab 2, Schedule 1, Attachment 4.

On February 26, 2020, Remotes applied for an exemption from the OEB's Capital Cost Allowance (CCA) and Tax Related Accounting Direction, specifically relating to the accelerated investment incentive (AII) program. Remotes requested that the exemption be retrospectively approved to November 20, 2018 and continue until Remotes' next rebasing application approval. On April 1, 2020, the OEB approved Remotes' exemption request, but noted that this request will be effective to December 31, 2027, when the AII program is expected to end, unless directed otherwise by the OEB as part of Remotes' next rebasing application.

NON-APPLICABILITY OF VARIOUS OEB ACCOUNTING REQUIREMENTS AND GUIDANCE

- <u>Accounting Guidance on Capacity Based Recovery, set out in the OEB's July 25, 2016 letter</u>: Remotes does not have account balances in Account 1580 sub-account CBR Class B.
- <u>Accounting Guidance with respect to changes to the Smart Metering Entity Charge (SME) set out in the OEB's March 23, 2018 letter</u>: Remotes does not charge SME to its customers.

[1] Report to the Ontario Energy Board, Activities and Program Benchmarking: 2020 Results, Pacific Economics Group Research LLC, 29 April 2022
[2] OEB Letter, Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance, July 25, 2019.

- Accounting Guidance related to Accounts 1588 Power, and 1589 RSVA Global Adjustment issued on February 21, 2019: Since Remotes does not have RPP and non-RPP customers, and does not have an Account 1589, this accounting guidance is not applicable to Remotes.

2.1 MATERIALITY THRESHOLDS

In terms of the materiality used by Hydro One Remotes, the following thresholds apply for distributors with less than 30,000 customers:

- 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10M and less than or equal to $200M

Hydro One Remotes' proposed total revenue requirement is $135M in 2023 which results in a materiality threshold of $673k.

2.2 DEVIATIONS FROM THE FILING REQUIREMENTS

Hydro One Remotes has complied with the OEB's policies and guidelines set out in the Handbook and Filing Requirements. Where modifications or updates were made in Chapter 2 Appendices file, references to what was amended are made in corresponding tabs of the OEB Workform:

- App.2-AB_Capital Expenditures
- App.2-IB_Load_Forecast_Analysis
- App.2-IB Consolidated
- App.2-IB Off Grid
- App.2-IB Grid

The Revenue Requirement Work Form is completed up to tab 9 as the rest of the tabs are not applicable to Remotes.

2.3 CHANGES TO METHODOLOGY & DESCRIPTION OF WHAT *CHANGED*

There are no changes to the methodology affecting the proposed calculation of revenue requirement.

3.0 EXEMPTION REQUEST FROM USE OF ACCOUNT 1588

Remotes would like to seek an exemption from the use of Account 1588 (RSVA – Power) due to the following reasons:

- The cost of power purchased from the IESO is recorded in Account 4705. Any variances between revenues collected from customers and costs paid to the IESO will be recoverable through the RRRP.
- Given that Remotes does not require disposition of Account 1588 to customers through separate rate riders, this negates the need to create an additional set of entries to record the cost of power purchased into Account 1588 on a monthly basis.
- Recording the monthly entries to reflect the transfer from Account 4705 to Account 1588, as required in the *OEB's Accounting Guidance related to Commodity Pass-Through Accounts* dated February 21, 2019, would be redundant for Remotes due to the circular nature of RRRP which functions to recover/return any variances between power sales and power costs incurred.

In the case of Remotes, Account 1589 does not apply as Remotes does not have non-RPP class B customers.

4.0 DISTRIBUTION SYSTEM PLAN

Remotes contracted with METSCO to assist with the development of a Distribution System Plan (DSP). METSCO is a company with experience assisting Distributors in developing these plans to meet OEB requirements. The DSP can be found at Exhibit B, Tab 2, Schedule 1.

5.0 RATE BASE

The Filing Requirements, past direction from the Board, and a number of specific government regulations influence the determination of Remotes' rate base and associated capital costs, as well as influencing the rate base information provided in the Application and in Exhibit B, Tab 1, Schedule 1.

5.1 DEPRECIATION RATES AND AMORTIZATION

Remotes' 2023 Revenue Requirement includes the depreciation and amortization rates that are based on a depreciation study conducted in 2022 by Alliance Consulting Group. This updated depreciation study can be found in Exhibit B, Tab 3, Schedule 1, Attachment 2.

Remotes recognizes a liability for estimated future expenditures required to remediate past environmental contamination associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. Since these expenditures are expected to be recoverable in future rates, Remotes has recognized an equivalent amount as a regulatory asset. This balance is amortized on a basis consistent with the pattern of actual expenditures expected to be incurred each year. Expenditures related to this remediation are discussed in Exhibit B, Tab 3, Schedule 1.

5.2 WORKING CAPITAL ALLOWANCE

Remotes' calculation for working capital is consistent with the default allowance as set out in the Filing Requirements and is shown in Exhibit B, Tab 1, Schedule 1.

5.3 INTEREST RATES FOR CONSTRUCTION WORK IN PROGRESS

The interest rate used for construction work in progress (CWIP) reflects the adoption of United States generally accepted accounting principles (US GAAP) per the Board's decision in EB-2011-0427. Under US GAAP, a utility capitalizes interest on qualifying capital programs and projects using its effective rate of its outstanding debt used to finance the capital expenditures made, unless the regulator requires the use of a specific allowance for funds used during construction rate (AFUDC). Consistent with its decisions in EB-2008-0408, effective January 1, 2012, no AFUDC is specified for use by Remotes. The construction work in progress evidence for the historical years, bridge year, and test year is filed in Exhibit B, Tab 4, Schedule 1.

5.4 CAPITAL PROJECTS AND PROGRAMS

Details for all capital projects and programs that exceed the materiality threshold of $673k in net capital costs (0.5% of revenue requirement) are provided in Investment Summary Documents (ISDs). The ISDs for these projects and programs are filed as attachments 1 through 9 to Exhibit B, Tab 2, Schedule 1.

5.5 IN-SERVICE ADDITIONS

Remotes continues to plan, manage and perform its internal and external reporting on a work basis using its general ledger accounts, as these are reflective of the way in which Remotes manages its operations. A schedule showing in-service additions by USofA accounts for 2023 test year, 2022 bridge year and 2018-2021 historical years is filed in Exhibit B, Tab 1, Schedule 2, Attachment 6.

6.0 COST OF CAPITAL

Remotes' cost of capital is based on a 100% debt financing structure, consistent with the Board's Decision in RP-1999-001. As Remotes operates as a break-even company, it does not plan to seek a return on capital. Further details can be found at Exhibit E, Tab 1, Schedule 1.

7.0 OPERATING (OM&A) COSTS

Remotes' OM&A evidence has been filed in Exhibit D, Tab 1, Schedule 1 through to Exhibit D, Tab 1, Schedule 8, which provide detailed information for the 2023 test year, 2022 bridge year, and 2018-2021 historical years.

8.0 OPERATING REVENUE AND REVENUE SUFFICIENCY/DEFICIENCY

The revenue sufficiency/deficiency for 2023 Remotes is shown in Exhibit F, Tab 1, Schedule 1, supported by calculations in the Revenue Requirement Workform filed at Exhibit F, Tab 1, Schedule 1, Attachments 1 and 2. The deficiency, calculated in Exhibit F, Tab 1, Schedule 1, Attachment 3 is recovered through the calculation of the annual RRRP as shown in Exhibit G, Tab 1, Schedule 1.

This page has been left blank intentionally.

Ontario

Electricity Distribution Licence

ED-2003-0037

Hydro One Remote Communities Inc.

Valid Until

December 23, 2023

Original signed by

Brian Hewson
Vice President, Consumer Protection and Industry Performance
Ontario Energy Board

Date of Issuance: December 24, 2003
Date of Amendment: March 31, 2017

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto, ON M4P 1E4

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

LIST OF AMENDMENTS

Board File No.	Date of Amendment
EB- 2004-0206	June 1, 2004
EB-2009-0363:	December 16, 2009
EB-2011-0021	April 25, 2013
EB-2016-0015	January 28, 2016
EB-2017-0101	March 31, 2017

Table of Contents **Page No.**

1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means Hydro One Remote Communities Inc.

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

2 **Interpretation**

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 **Authorization**

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence; and

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence.

4 **Obligation to Comply with Legislation, Regulations and Market Rules**

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 **Obligation to Comply with Codes**

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; and

b) the Distribution System Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 **Obligation to Sell Electricity**

6.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Licensee's Rate Order as approved by the Board.

7 **Obligation to Maintain System Integrity**

7.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

8 **Market Power Mitigation Rebates**

8.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

9 **Distribution Rates**

9.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

10 **Separation of Business Activities**

10.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

11 **Expansion of Distribution System**

11.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

11.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

12 **Provision of Information to the Board**

12.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

12.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

13 **Restrictions on Provision of Information**

13.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

13.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection, band council or government agency for the processing of past due accounts of the consumer or generator.

13.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

13.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

13.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

14 **Customer Complaint and Dispute Resolution**

14.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

15 **Term of Licence**

15.1 This Licence shall take effect on December 24, 2003 and expire on December 23, 2023. The term of this Licence may be extended by the Board.

16 **Fees and Assessments**

16.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

17 **Communication**

17.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

17.2 All official communication relating to this Licence shall be in writing.

17.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender=s transmission report.

18 **Copies of the Licence**

18.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

19 **Pole Attachments**

19.1 The Licensee shall provide access to its distribution poles to all Canadian carriers, as defined by the Telecommunications Act, and to all cable companies that operate in the Province of Ontario. For each attachment, with the exception of wireless attachments, the Licensee shall charge the rate approved by the Board and included in the Licensee’s tariff.

19.2 The Licensee shall:

a) annually report the net revenue, and the calculations used to determine that net revenue, earned from allowing wireless attachments to its poles. Net revenues will be accumulated in a deferral account approved by the Board;

b) credit that net revenue against its revenue requirement subject to Board approval in rate proceedings; and

c) provide access for wireless attachments to its poles on commercial terms normally found in a competitive market.

20 Winter 2016/17 Disconnection, Reconnection and Load Limiter Devices

20.1 Subject to paragraph 20.4, the Licensee shall not, during the period commencing February 24, 2017 and ending at 11:59 pm on April 30, 2017:

a) disconnect an occupied residential property solely on the grounds of non-payment;

b) issue a disconnection notice in respect of an occupied residential property solely on the grounds of non-payment; or

c) install a load limiter device in respect of an occupied residential property solely on the grounds of non-payment.

Nothing in this paragraph shall preclude the Licensee from (i) disconnecting an occupied residential property in accordance with all applicable regulatory requirements, including the required disconnection notice; or (ii) installing a load limiter device in respect of an occupied residential property, in each case if at the unsolicited request of the customer given in writing on or after February 24, 2017.

20.2 Subject to paragraph 20.4, if the Licensee had disconnected a residential property on or before February 23, 2017 solely on the grounds of non-payment, the Licensee shall reconnect that property, if an occupied residential property, as soon as possible. The Licensee shall waive any reconnection charge that might otherwise apply in respect of that reconnection.

Nothing in this paragraph shall require the Licensee to reconnect an occupied residential property if the customer gives unsolicited notice to the Licensee not to do so in writing on or after February 24, 2017.

20.3 Subject to paragraph 20.4, if the Licensee had installed a load limiter device in respect of an occupied residential property on or before February 23, 2017 either for non-payment or at the customer's request, the Licensee shall remove that device and restore full service to the property as soon as possible. The Licensee shall waive any charge that might otherwise apply in respect of such removal.

Nothing in this paragraph shall: (i) require the Licensee to remove a load limiter device if the customer gives unsolicited notice to the Licensee not to do so in writing on or after February 24, 2017; or (ii) prevent the Licensee from installing or maintaining a load limiter device at the unsolicited request of customer given in writing on or after February 24, 2017.

20.4 Nothing in paragraphs 20.1 to 20.3 shall:

a) prevent the Licensee from taking such action in respect of an occupied residential property as may be required to comply with any applicable and generally acceptable safety requirements or standards; or

b) require the Licensee to act in a manner contrary to any applicable and generally accepted safety requirements or standards.

20.5 The Licensee shall waive any collection of account charge that could otherwise be charged in relation to an occupied residential property during the period referred to in paragraph 20.1.

20.6 The Licensee shall provide the Board with periodic reports on its progress in complying with paragraphs 20.2 and 20.3. The first such report shall be filed with the Board no later than March 3, 2017, and reports shall be provided every 7 calendar days thereafter until such time as no further action remains to be taken by the Licensee under those paragraphs.

20.7 For the purposes of paragraphs 20.1 to 20.4:

"load limiter device" means a device that will allow a customer to run a small number of electrical items in his or her premises at any given time, and if the customer exceeds the limit of the load limiter, then the device will interrupt the power until it is reset; and

"occupied residential property" means an account with the Licensee:

a) that falls within the residential rate classification as specified in the Licensee's Rate Order; and
b) that is:

i) inhabited; or
ii) in an uninhabited condition as a result of the property having been disconnected by the Licensee or of a load limiter device having been installed in respect of the property on or before February 23, 2017.

20.8 Paragraphs 20.1 to 20.5 apply despite any provision of the Distribution System Code to the contrary.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 6.1 of this Licence.

1. Armstrong
2 Bearskin Lake
3. Big Trout Lake
4. Biscotasing
5. Collins
6. Deer Lake
7. Fort Severn
8 Gull Bay
9 Hillsport
10. Kasabonika Lake
11. Kingfisher Lake
12. Landsdowne House
13. Oba
14. Sachigo Lake
15. Sandy Lake
16. Sultan
17. Wapakeka
18. Weagamow
19. Webequie
20 Whitesand
21 Marten Falls (operated by the Licensee, owned by Marten Falls First Nation)

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 6.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements that are not applicable to the Licensee.

1. The entire Retail Settlement Code

2. The entire Standard Supply Service Code

3. Sections 2.7.1.2; 2.7.1.3; 2.7.2; 2.8.1; 2.8.2; 4.2.2.3; 4.2.3.1(a); 6.1.2.1; 6.1.2.2 and 7.10 of the Distribution System Code.

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Ontario

Electricity Generation Licence

EG-2003-0138

Hydro One Remote Communities Inc.

Valid Until

October 19, 2023

Original signed

Jennifer Lea
Counsel, Special Projects
Ontario Energy Board
Date of Issuance: October 20, 2003
Date of Amendment: June 1, 2004
Date of Amendment: December 16, 2009

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th. Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

Table of Contents **Page No.**

1 Definitions

In this Licence:

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**generation facility**" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system and includes any structures, equipment or other things used for that purpose;

"**Licensee**" means Hydro One Remote Communities Inc.;

"**regulation**" means a regulation made under the Act or the Electricity Act;

2 Interpretation

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of this Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this licence:

a) to generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person subject to the conditions set out in this Licence. This Licence authorizes the Licensee only in respect of those facilities set out in Schedule 1;

b) to purchase electricity or ancillary services in the IESO-administered markets or directly from a generator subject to the conditions set out in this Licence; and

c) to sell electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer, subject to the conditions set out in this Licence.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act, and regulations under these acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Maintain System Integrity

5.1 Where the IESO has identified, pursuant to the conditions of its licence and the Market Rules, that it is necessary for purposes of maintaining the reliability and security of the IESO-controlled grid, for the Licensee to provide energy or ancillary services, the IESO may require the Licensee to enter into an agreement for the supply of energy or such services.

5.2 Where an agreement is entered into in accordance with paragraph 5.1, it shall comply with the applicable provisions of the Market Rules or such other conditions as the Board may consider reasonable. The agreement shall be subject to approval by the Board prior to its implementation. Unresolved disputes relating to the terms of the Agreement, the interpretation of the Agreement, or amendment of the Agreement, may be determined by the Board.

6 Restrictions on Certain Business Activities

6.1 Neither the Licensee, nor an affiliate of the Licensee shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario except in accordance with section 81 of the Act.

7 Provision of Information to the Board

7.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

7.2 Without limiting the generality of paragraph 7.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee, as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

8 Term of Licence

8.1 This Licence shall take effect on October 20, 2003 and expire on October 19, 2023. The term of this Licence may be extended by the Board.

9 Fees and Assessments

9.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

10 Communication

10.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

10.2 All official communication relating to this Licence shall be in writing.

10.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; or

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

11 Copies of the Licence

11.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 LIST OF LICENSED GENERATION FACILITIES

The Licence authorizes the Licensee only in respect to the following:

1. Armstrong Generation Station, owned and operated by the Licensee at Armstrong, Ontario.
2. Bearskin Lake Generation Station, owned and operated by the Licensee at Bearskin Lake, Ontario.
3. Big Trout Lake Generation Station, owned and operated by the Licensee at Big Trout Lake, Ontario.
4. Biscotasing Generation Station, owned and operated by the Licensee at Biscotasing, Ontario.
5. Dear Lake Generation Station, owned and operated by the Licensee at Dear Lake, Ontario.
6. Fort Severn Generation Station, owned and operated by the Licensee at Fort Severn, Ontario.
7. Gull Bay Generation Station, owned and operated by the Licensee at Gull Bay, Ontario.
8. Hillsport Generation Station, owned and operated by the Licensee at Hillsport, Ontario.
9. Kasabonika Generation Station, owned and operated by the Licensee at Kasabonika Lake, Ontario.
10. Kingfisher Lake Generation Station, owned and operated by the Licensee at Kingfisher Lake, Ontario.
11. Lansdowne House Generation Station, owned and operated by the Licensee at Lansdowne House, Ontario.
12. Oba Generation Station, owned and operated by the Licensee at Oba, Ontario.
13. Sachigo Lake Generation Station, owned and operated by the Licensee at Sachigo Lake, Ontario.
14. Sandy Lake Generation Station, owned and operated by the Licensee at Sandy Lake, Ontario.
15. Sultan Generation Station, owned and operated by the Licensee at Sultan, Ontario.
16. Wapekeka Generation Station, owned and operated by the Licensee at Wapekeka, Ontario.

17 Weagamow Lake Generation Station, owned and operated by the Licensee at Weagamow Lake, Ontario.

18. Webequie Generation Station, owned and operated by the Licensee at Webequie, Ontario.
19. Deer Lake Mini Hydel Generation Station, owned and operated by the Licensee at Deer Lake, Ontario.
20. Sultan Hydel Generation Station, owned and operated by the Licensee at Sultan, Ontario.

21. Marten Falls Generation Station, operated by the Licensee at Marten Falls, Ontario.

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
GENERAL REQUIREMENTS		
Ch1, p4	Confidential Information - Practice Direction has been followed	Exhibit A, Tab 1, Schedule 3
Ch1, p5	Certification by a senior officer that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction, as applicable) .	Exhibit A, Tab 1, Schedule 3, Attachment 2
Ch1, p5	Certification by a senior officer that the evidence filed (including the models and appendices) is accurate, consistent and complete to the best of their knowledge	Exhibit A, Tab 1, Schedule 3, Attachment 1
Ch1, p5	Certification by the Chief Executive Officer, or Chief Financial Officer, or equivalent, that the distributor has the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts, regardless of whether the accounts are proposed for disposition	Exhibit A, Tab 1, Schedule 3, Attachment 3
Ch2, p2	COS checklist filed and statement identifying all deviations from Filing Requirements	Exhibit A, Tab 2, Schedule 1, Attachment 3; Exhibit A, Tab 2, Schedule 1
2 & 3	Chapter 2 appendices in live Excel format; PDF and Excel copy of current tariff sheet	Exhibit A, Tab 2, Schedule 2, Attachment 1 and Exhibit G, Tab 3, Schedule 2
3	If distributor updates/amends an OEB model, reference made in corresponding exhibit re: what was amended	Exhibit A, Tab 2, Schedule 1
3	Regulated entity shown separately from parent company or any other affiliates	Exhibit A, Tab 6, Schedule 1 and Exhibit A, Tab 6, Schedule 1, Attachment 1
3	If applicable, if cost of service filed earlier than scheduled, threshold for early rebasing as established in April 2020 letter met	Not Applicable. Hydro One Remotes Communities Inc. has filed its Application by August 31, 2022
4	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year	Not Applicable. Hydro One Remotes Communities Inc. has filed its Application by August 31, 2022
4	All of the following exhibits filed: Administrative Documents, Rate Base (including DSP), Customer and Load Forecast, Operating Expenses, Cost of Capital and Capital Structure, Revenue Requirement and Revenue Deficiency/Sufficiency, Cost Allocation, Rate Design, Deferral and Variance Accounts	Confirmed
5	General requirements applicable throughout application: -written evidence included before data schedules -avg. of opening and closing fiscal year balances used for items in rate base (unless alternative method justified) -debt + equity = total rate base -data for test year, bridge year, three most recent historicals (or as many needed to provide actuals back to last OEB-approved), most recent OEB-approved test	Confirmed. Please also see Exhibit A, Tab 1, Schedule 2
5	Text searchable and bookmarked PDF documents	Confirmed
6	Links within Excel models are broken and models named so that they can be identified (e.g. RRWF instead of Attachment A)	Confirmed
6	Materiality threshold; explanations for rate base, capex, and OM&A if revenue requirement impact is greater than the materiality threshold; additional details below the threshold if necessary	Exhibit A, Tab 2, Schedule 1
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS		
Table of Contents		
7	Table of Contents listing major sections and subsections of the application	Exhibit A, Tab 1, Schedule 1
Application Summary and Business Plan		
7	Distributor with less than 30k customers: Business and/or Strategic Plan. If no Business or Strategic plan: key planning assumptions, description of material factors (internal and external) that may affect the operation of the utility and major goals of the distributor in the test year and remaining years of the five-year term. Distributor with 30k or more customers: Business Plan underpinning application - can be augmented by plain language summary of distributor's goals that informed the application if this is not otherwise in the business plan.	Exhibit A, Tab 3, Schedule 1 and Exhibit A, Tab 3, Schedule 1, Attachment 1

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
7 & 8	Brief, plain langauge summary of the application which includes the main requests with section references and rationale behind each request. Must include: -Revenue requirement (service revenue requirement requested for test year, increase/decrease ($ and %) from most recent approved, main drivers of revenue requirement changes -Load forecast summary (load and customer growth (% change in kWh, kW and change in customer #s from last OEB-approved)) -Rate base and DSP (major drivers of DSP, rate base requested, change in rate base from last OEB-approved ($ and %), CAPEX for test year, change in CAPEX from last OEB-approved ($ and %) -OM&A (OM&A for test and change from last OEB-approved ($ and %), drivers and cost trends) -Cost of capital (table showing proposed capital structure and parameters resulting in WACC, statement confirming use of OEB's cost of capital parameters, summary of deviations from OEB methodology) -Cost allocation and rate design (proposed new customer classes and/or customer definition changes, significant changes proposed to rev. cost ratios and fixed/variable split, mitigation plans) -DVAs (total disposition ($) including split between RPP and non-RPP, disposition period, new DVAs and requested discontinuation of DVAs) -Bill Impacts ($ and %) for residential customer at 750kWh, and typical customers for all other classes (based on commodity rates on TOU with regulatory charges held constant; bill impacts to be used for Notice (Sub-total A) for residential customer at 750kWh and GS<50 at 2000kWh as well as a typical consumer for a distributor's service area for all customer classes, and bill impacts based on alternative consumption profiles and customer groups as appropriate	Exhibit A, Tab 1, Schedule 2
Administration		
9	Primary contact information (name, address, phone, email)	Exhibit A, Tab 1, Schedule 3
9	Identification of legal (or other) representation	Exhibit A, Tab 1, Schedule 3
9	Applicant's internet address for viewing of application and any social media accounts, with addresses, used by the applicant to communicate with customers	Exhibit A, Tab 1, Schedule 3
9	Statement identifying where notice should be published and why	Exhibit A, Tab 1, Schedule 3
9	Form of hearing requested and why	Exhibit A, Tab 1, Schedule 3
9	Requested effective date	Exhibit A, Tab 1, Schedule 3
9	Statement identifying and describing any changes to methodologies used vs previous applications	Exhibit A, Tab 2, Schedule 1
9	Identification of OEB directions from any previous OEB Decisions and/or Orders, including commitments made as part of approved settlements. Indication of how these are being addressed in the current application	Exhibit A, Tab 2, Schedule 1
9	Reference to Conditions of Service - provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application and/or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	Exhibit A, Tab 1, Schedule 3
9 & 10	Description of the corporate and utility organizational structure showing the main units and executive and senior management positions within the distributor; corporate entities relationship chart, showing the extent to which the parent company is represented on the distributor company's Board of Directors; description of the reporting relationships between distributor and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	Exhibit A, Tab 6, Schedule 1 and Attachments
10	List of approvals requested (and relevant section of legislation). All approvals including accounting orders, new rate classes, revised specific service charges or retail service charges which the distributor is seeking, must be documented - Appendix 2-A provided, but not required to be used by LDC	Exhibit A, Tab 1, Schedule 3
Distribution System Overview		
10	Description of Service Area - general description and map showing where distributor operates and communities served	Exhibit A, Tab 1, Schedule 4, Attachment 1 and Exhibit B, Tab 2, Schedule 1 (Section 5.2.1.3)
Customer Engagement		
10	Discussion on how utility communicates with customers on a regular basis	Exhibit A, Tab 4, Schedule 1 and Exhibit B, Tab 2, Schedule 1 (Section 5.2.2.1)
10	Discussion on how the proposals in the application were communicated to customers	Exhibit A, Tab 4, Schedule 1 and Exhibit B, Tab 2, Schedule 1 (Section 5.2.2.1)
10	Discussion of any feedback provided by customers and how the feedback informed the final application	Exhibit A, Tab 4, Schedule 1 and Exhibit B, Tab 2, Schedule 1 (Section 5.2.2.1)
10	Customer consultation with customers who would be affected by proposals related to new classes, elimination of classes, change in class definition, and change in charges such as RSCs, Specific Service Charges and standby rates	Exhibit A, Tab 1, Schedule 2

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
10	Documentation of communications with unmetered load customers (incl. Street lighting), and how distributor helped them to understand the regulatory context in which the distributor operates and how it affects unmetered scattered load customers	Exhibit A, Tab 4, Schedule 1
10	Description of any other communication sent to customers about the application such as bill inserts, town hall meetings or other forms of outreach. Appendix 2-AC Customer Engagement Activities Summary **may** be used to assist in listing customer engagement activities	Exhibit A, Tab 4, Schedule 1 and Exhibit B, Tab 2, Schedule 1 (Section 5.2.2.1)
11	All responses to matters raised in letters of comment filed with the OEB	No letters of comment were filed with the OEB in regards to this application.
Performance Measurement		
11	Link to most recent scorecard	Exhibit A, Tab 1, Schedule 5, Attachment 1
11	Identification of performance improvement targets	Exhibit A, Tab 1, Schedule 5
11	PEG Model for the test year showing efficiency assessment, discussion on how the results obtained from the PEG model has informed the distributor's business plan and application	Not Applicable. Please see Exhibit A, Tab 2, Schedule 1.
11	Distributors **may** wish to provide table showing respective OEB-approved IRM increases for each of the last historical years from last rebasing, and assigned cohort as per PEG model	Exhibit A, Tab 1, Schedule 5
11	Activity and Performance-based Benchmarking (APB) results - discussion of performance for each of the ten programs and provide any immediate remedial actions distributor plans to take; how the APB results will influence future planning	Not Applicable. Please see Exhibit A, Tab 2, Schedule 1.
Facilitating Innovation		
12	Distributors are encouraged to include a description of the ways their approach to innovation have shaped the application. Could include an explanation of approach to innovation in its business more generally, or related to specific projects or technologies, including enabling characteristics or constraints in its ability to undertake innovative solutions, for enhancing the provision of distribution services in a way that benefits customers, or facilitating customers ability to innovate in how it receives electricity. Distributors could also include an explanation of how innovative alternatives have been considered in place of traditional investments.	Exhibit A, Tab 1, Schedule 6
Financial Information		
12 & 13	Audited Financial Statements (excluding operations of affiliated companies that are not rate regulated) for two most recent historical years (i.e. one year's statements must be filed, covering two years of historical actuals); if most recent finals n/a, draft financial statements filed and finals, along with summary of main changes if there are any, provided as soon as they are available. Alternatively, if distributor publishes financial statement on its website, a link may be provided	Exhibit A, Tab 1, Schedule 7, Attachments 1 to 4
13	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable	Exhibit A, Tab 1, Schedule 7
13	Rating Agency Reports, if available; Prospectuses, information circulars etc. for recent and planned public issuances	Not Applicable. The rating agency reports are performed at the holding company level. Remotes does not impact these reports.
13	Any change in tax status	No change in tax status
13	Description of existing accounting orders and departures from these orders, as well as any departures from the USoA	Exhibit H, Tab 1, Schedule 1. Remotes has not been approved of any specific accounting orders and has not departed from USofA.
13	Accounting Standards used for financial statements and when adopted	Exhibit A, Tab 1, Schedule 7
13	If distributor conducting non-distribution businesses, confirmation that accounting treatment used has segregated these activities from rate regulated activities	Not Applicable. Remotes does not have any non-utility business
Distributor Consolidation		
13	Distributor with less than 30k customers: information filed on the extent to which the distributor has investigated opportunities from consolidation or collaboration/partnerships with other distributors (contained within a dedicated section of the application); conclusions from investigations, including future plans	Not Applicable. See Exhibit A, Tab 1, Schedule 8. Remotes has not, nor expects to, participate in any regulated distributor consolidation activities over the term of this application.
13	If distributor has become party to a proposed or approved MAADs transaction since last rebasing, disclosure of this information in current application	Not Applicable. See Exhibit A, Tab 1, Schedule 8
A distributor filing an application to rebase following a consolidation must:		
14	Identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement - list the exhibits in which incentives are discussed	Not Applicable. See Exhibit A, Tab 1, Schedule 8
14	Specify whether and which commitments made to shareholders are to be funded through rates	Not Applicable. See Exhibit A, Tab 1, Schedule 8
14	Detail of realized and projected savings as a result of consolidation compared to what was in the approved consolidation application and explanation of the nature of these savings (e.g. one-time, ongoing etc.)	Not Applicable. See Exhibit A, Tab 1, Schedule 8
14	Detail of efficacy of any rate plan confirmed as part of MAADs	Not Applicable. See Exhibit A, Tab 1, Schedule 8
14	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base	Not Applicable. See Exhibit A, Tab 1, Schedule 8
Impacts of COVID-19 Pandemic		
14	Distributors generally expected to reflect the impacts of the COVID-19 pandemic in their applications, including applicable forecasted information. This includes, but is not limited to, the applicant's load forecast, capital forecast, and OM&A forecast in the applicable sections of the application	Exhibit A, Tab 1, Schedule 9
EXHIBIT 2 - RATE BASE		
Rate Base		
14	Indication of whether capital expenditures are equivalent to in-service additions, and if so, variance explanations only required once. Specify whether variance explanations are on CAPEX or in-service additions basis	Exhibit B, Tab 1, Schedule 1
14 & 15	For rate base, opening and closing balances for each year, and the average of the opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance	Exhibit B, Tab 1, Schedule 2, Attachments 2 and 3
15	Table showing components of the last OEB-approved rate base, the proposed test year rate base and the variances	Exhibit B, Tab 1, Schedule 1
Fixed Asset Continuity Schedule		
15	Completed Appendix 2-BA for each year - in Excel format	Exhibit A, Tab 2, Schedule 2, Attachment 1

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
15	Continuity statements and year-over-year variance analysis must be provided (year end balance, including capitalized interest during construction and overhead costs). Explanations provided where there is a year-over-year variance greater than the applicable materiality threshold If applicable, explanation for any restatement (e.g. due to change in accounting standards) and reconciliation to original statements Year over year variance analysis; explanation where variance greater than materiality threshold. The following comparisons must be provided: Hist. OEB-Approved vs Hist. Actual (for the most recent historical OEB-approved year) Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) Hist. Act. vs. Bridge Bridge vs. Test	Exhibit B, Tab 1, Schedule 2 See Appendix 2-BA filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
15	Opening and closing balances of gross assets and accumulated depreciation correspond to fixed asset continuity statements. If not, an explanation and reconciliation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Confirmed. Exhibit B, Tab 1, Schedule 2, Attachments 2 and 3
15	Distributor may include in-service balances previously recorded in DVAs, such as renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, and disposition is being requested in this application. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation	Confirmed. Exhibit B, Tab 1, Schedule 2, Attachments 2 and 3
Gross Assets - PP&E and Accumulated Depreciation		
16	Groupings by function (transmission or high voltage plant, distribution plant, general plant, other plant) for required statements and analyses	Exhibit B, Tab 1, Schedule 2, Attachments 1 to 4
16	Componentization by major plant account for each functionalized plant item; for test year, each plant item must be accompanied by description	Exhibit B, Tab 1, Schedule 2, Attachments 1 to 4
16	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	Remotes has not requested any ICM or ACM in its IRM applications
16	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Appendix 2-BA filed at Exhibit A, Tab 2, Schedule 2, Attachment 1 Exhibit B, Tab 3, Schedule 1, Attachment 1
16	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years	Appendix 2-BA filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
Depreciation, Amortization and Depletion		
17	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	Remotes is not proposing any changes in depreciation related to useful life of assets
17	Depreciation, amortization and depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	Appendix 2-C filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
17	Identification of any Asset Retirement Obligations and associated depreciation or accretion expense - includes the basis for and calculation of these amounts	Exhibit B, Tab 3, Schedule 1. Remotes does not have any ARO at this time.
17	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	Exhibit B, Tab 3, Schedule 1. There are no variances from half year rule.
17	Copy of depreciation/amortization policy if available. If not, equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Exhibit B, Tab 3, Schedule 1, Attachment 2
17	If filing under MIFRS, explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	Not Applicable, as Remotes is currently reporting under US GAAP for regulatory purposes.
18	If no changes have been made to depreciation policy or service lives since last rebasing, a statement confirming that this is the case is required. For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA and reconcile this list to the USoA, detail differences in asset service lives and the TULs from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB if there have been changes in asset service lives since last rebasing	Exhibit B, Tab 3, Schedule 1 Appendix 2-BB is not applicable for the reasons discussed in Exhibit A, Tab 2, Schedule 2
Allowance for Working Capital		
18	Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction	Exhibit B, Tab 1, Schedule 1
18	Lead/Lag Study - leads and lags measured in days, dollar-weighted and reflects the distributor's actual billing and settlement processing timelines and considers relevant changes to operating environment	Not Applicable. Remotes is using the default allowance
19	Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price. Calculation must include the impact of the most up to date Ontario Electricity Rebate. Distributors must complete Appendix 2-Z - Commodity Expense.	Remotes' customers are not part of the Regulated Price Plan. (Rates are bundled and established through RRRP Regulation)
19	Use most recent approved UTRs, Smart Metering Entity Charge and regulatory charges	Remotes' customers are not part of the Regulated Price Plan. (Rates are bundled and established through RRRP Regulation)
Distribution System Plan		
19	DSP filed as a stand-alone, self-sufficient element within Exhibit 2	Exhibit B, Tab 2, Schedule 1
Policy Options for the Funding of Capital		
19	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP) - provide information on need and prudence	Remotes is not proposing ACM capital treatment for any projects at this time. See Exhibit A, Tab 2, Schedule 2
19	Identification that distributor is proposing ACM treatment for these future projects, and provide the preliminary cost information and ACM/ICM materiality threshold calculations - ACM Report provides further details on information required	Remotes is not proposing ACM capital treatment for any projects at this time. See Exhibit A, Tab 2, Schedule 2

July 20, 2016

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
19	Complete Capital Module Applicable to ACM and ICM	Remotes is not proposing ACM capital treatment for any projects at this time. See Exhibit A, Tab 2, Schedule 2
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		
20	Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base (i.e. PP&E and associated depreciation). Comparison of actual capital spending with OEB-approved amount and explanation for variances	Remotes has not requested ACM capital treatment in its IRM applications.
21	Balances in Account 1508 sub-accounts; rate of interest prescribed by the OEB for DVAs for the respective quarterly period as published on the OEB's website	Not Applicable, as Remotes has not requested ACM capital treatment in its IRM applications.
21	True-up calculation if material, comparing the recalculated revenue requirement based on actual capital spending relating to the OEB-approved ACM/ICM project(s) to the rate rider revenues collected in the same period; assumptions used in the calculation noted (e.g. half-year rule).	Not Applicable, as Remotes has not requested ACM capital treatment in its IRM applications.
21	Accelerated capital cost allowance (CCA) should not be reflected in the ACM/ICM revenue requirement associated with these projects. Distributors should include the impact of the CCA rule change associated with the ACM/ICM project(s) in Account 1592 - PILs and Tax Variances – CCA Changes sub-account for CCA changes	Not Applicable, as Remotes has not requested ACM capital treatment in its IRM applications.
Capitalization		
22	Capitalization Policy: provide policy including changes since last rebasing application	Exhibit B, Tab 4, Schedule 1 There have been no changes in capitalization policy since last rebasing.
22	Overhead Costs: complete Appendix 2-D	Appendix 2-D filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
22	Burden Rates: identification of burden rates; if burden rates were changed since last rebasing, identification of the burden rates prior to the change	Exhibit B, Tab 4, Schedule 1 Exhibit D, Tab 2, Schedule 2
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities		
22	See Appendix A	Not Applicable, as Remotes is not applying for provincial funding for renewable generation investments.
General & Administrative Matters		
Ch5, p2	Use of terminology and formats set out in Ch. 5	Confirmed
Investment Categories		
Ch5, pp 2, 3 & 4	Investment projects and programs grouped into one of four investment categories (i.e. system access, system renewal, system service, general plant)	
Distribution System Plan		
Ch5, p4	If a distributor's application uses alternative section headings and/or arranges the information in a different order, table provided that cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in Ch. 5	Not Applicable. Generally follows the form of the Ch 5 Filing Requirements.
Ch5, p4 & 5	DSP duration minimum of 10 years, comprising of a historical and forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of a distributor's last cost or service application to the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year.	Exhibit B, Tab 2, Schedule 1, Section 5.2.1
Distribution System Plan Overview		
Ch5, p5	High-level overview of information filed in DSP which includes capital investment highlights and changes since last DSP; objectives distributor plans to achieve through DSP	Exhibit B, Tab 2, Schedule 1, Section 5.2.1
Coordinated Planning with Third Parties		
Ch5, p5	Demonstration of OEB's expectations related to coordinated planning with third parties where appropriate. Explanation of whether consultations affected distributor's DSP, and if so, how; for consultations that affected DSP - overview of consultation, material used, copy of final deliverable if available	Exhibit B, Tab 2, Schedule 1, Section 5.2.2
Ch5, p5	Description of consultation should include: purpose, whether the distributor initiated the consultation or was invited to participate in it, and the other participants in the consultation process	Exhibit B, Tab 2, Schedule 1, Section 5.2.2
Ch5, p5 & 6	Identification of any inconsistencies between DSP and any current Regional Plan. If there are any inconsistencies, explanation of the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan	Exhibit B, Tab 2, Schedule 1, Section 5.2.2

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Ch5, p6 & OEB Letter, Jan. 11, 2022	Telecommunications Entities: -see January 11, 2022 letter for further guidance to the regulation that requires distributors to consult with any telecommunications entity that operates within its service area when preparing a capital plan for submission to the OEB, for the purpose of facilitating the provision of telecommunications services, and include information in its capital plan	Exhibit B, Tab 2, Schedule 1, Section 5.2.6
Ch5, p6	REG: -confirmation if there are no REG investments in region -if there REG investments proposed in DSP, demonstration of coordination with IESO, other distributors/transmitters (as applicable), and that investments proposed are consistent with Regional Infrastructure Plan - IESO letter in relation to REG investments	Exhibit B, Tab 2, Schedule 1, Section 5.2.4
Performance Measurement for Continuous Improvement		
Ch5, p6	Distribution System Plan: Summary of objectives for continuous improvement set out in last DSP and discussion on whether these objectives achieved or not. For objectives not achieved, explanation of how this affects current DSP and if applicable, improvements implemented to achieve the objectives in current DSP	Exhibit B, Tab 2, Schedule 1, Section 5.2.3
Ch5, pp 6 & 7	Service Quality and Reliability: -5 historical years of SQRs; explanations for material changes in service quality and reliability and whether and how DSP addresses these issues -for reliability, any declining 5 year SAIDI/SAIFI trends explained -if reliability targets established in last DSP, any under-performance explained	Exhibit B, Tab 2, Schedule 1, Section 5.2.3.1.3.1
Ch5, p7	Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	Exhibit A, Tab 2, Schedule 2, Attachment 1
Ch5, p7	Summary of performance for historical period using methods and measures (metrics/targets) identified and how performance has trended over the period. Summary must include historical period data on: -all interruptions -all interruptions excluding loss of supply -all interruptions excluding major events and loss of supply for: SAIFI, SAIDI	Exhibit B, Tab 2, Schedule 1, Section 5.2.3.1.3
Ch5, p7	Summary of major events that occurred since last cost of service	Exhibit A, Tab 5, Schedule 2
Ch5, p7	For each cause of interruption for last five historical years: number of interruptions that occurred as a result of the cause of interruption, number of customer interruptions that occurred as a result of interruption, number of customer-hours of interruptions that occurred as a result of the cause of interruption	Exhibit B, Tab 2, Schedule 1, Section 5.2.3.1.3.2
Ch5, pp7 & 8	Distributor Specific Reliability Targets: -if establishing performance expectations based on something other than historical performance, evidence provided of capital and operational plan and other factors that justify the reliability performance the distributor plans to deliver -summary of any feedback from customers regarding reliability on distributor's system -distributors that use SAIDI and SAIFI performance benchmarks that are different than the historical average - evidence provided to support reasonableness of benchmarks	Exhibit B, Tab 2, Schedule 1, Section 5.2.3.1.3.3
Planning Process		
Ch5, p8	Overview of planning process that has informed five-year capital expenditure plan; flowchart accompanied by explanatory text **may** be helpful	Exhibit B, Tab 2, Schedule 1, Section 5.3.1
Ch5, p8	Summary of important changes in distributor's AM process since last DSP	Exhibit B, Tab 2, Schedule 1, Section 5.3.1.2
Ch5, p8 & 9	Process: -provide processes used to identify, select, prioritize (including reprioritization over 5 year term), and pace execution of investments -demonstration that distributor has considered correlation between plan and customer's feedback and needs -demonstration that distributor has considered potential risks of proceeding/not proceeding with individual capital expenditures -consideration, where applicable, of assessing the use of non-distribution alternatives, cost-effective implementation of distribution improvements affecting reliability, and meeting customer needs as acceptable costs to customers, other innovative technologies, and consideration of dx funded CDM activities	Exhibit B, Tab 2, Schedule 1, Section 5.3.1.3
Ch5, p9	Data -identification, description and summary of data used in processes above to identify, select, prioritize and pace investments over DSP	Exhibit B, Tab 2, Schedule 1, Section 5.3.1.4
Overview of Assets Managed		
Ch5, p9	Overview of service area (e.g. system configuration, urban/rural etc.) to support capital expenditures over forecast period; asset information (e.g. capacity, condition, asset risks etc.) by major asset type that may help explain the specific need of the capital expenditure and demonstration of consideration of economical alternatives	Exhibit B, Tab 2, Schedule 1, Section 5.3.2
Ch5, p9	Statement as to whether or not distributor has had any transmission or high voltage assets deemed previously by the OEB as distribution assets, and whether or not there are any such assets that the distributor is asking the OEB to deem as distribution assets in the current application	Exhibit B, Tab 2, Schedule 1, Section 5.3.2.3
Ch5, p9	Description of whether distributor is a host and/or embedded distributor; identification of any embedded and/or host distributors; partially embedded status identified (including % of total load supplied through host); if host distributor, identification of whether there is a separate embedded class or if any embedded distributors are included in other classes	Exhibit B, Tab 2, Schedule 1, Section 5.3.2.4
Asset Lifestyle Optimization Policies and Practices		
Ch5, p10	Demonstration that distributor has carried out system O&M activities to sustain as asset to the end of its service life (can include references to the Distribution System Code)	Exhibit B, Tab 2, Schedule 1, Section 5.3.3
Ch5, p10	Explanation of processes and tools used to forecast, prioritize and optimize system renewal spending and how distributor intends to operate within budget envelopes	Exhibit B, Tab 2, Schedule 1, Section 5.3.3.3
Ch5, p10	Demonstration of consideration of potential risks of proceeding/not proceeding with individual capital expenditures	Exhibit B, Tab 2, Schedule 1, Section 5.3.3.3.5
Ch5, p10	Summary of important changes to the distributor's asset life optimization policies and processes since last DSP	Exhibit B, Tab 2, Schedule 1, Section 5.3.3.4
System Capability Assessment for REG		
Ch5, p10	If a distributor has costs to accommodate and connect renewable generation facilities that will be the responsibility of the distributor under the DSC, refer to Appendix A	Exhibit B, Tab 2, Schedule 1, Section 5.3.4

July 20, 2016

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
CDM Activities to Address System Needs		
Ch5, p10	Description of how distributor has taken CDM into consideration in its planning process	Exhibit B, Tab 2, Schedule 1, Section 5.3.5.1
Ch5, p11	Any application for CDM funding to address system needs must include a consideration of the projected effects to the distribution system on a long-term basis and the forecast expenditures.	Not Applicable. See section 5.3.5 of the DSP (Exhibit B-02-01)
Ch5, p11	Explanation of proposed activity in the context of the DSP or explanation of any changes to system plans that are pertinent to the activity	Not Applicable. See section 5.3.5 of the DSP (Exhibit B-02-01)
Capital Expenditure Summary		
Ch5, p11	Provide capital expenditure plan that sets out proposed expenditures on distribution system and general plant over a five-year planning period, including investment and asset-related operating and maintenance expenditures	Exhibit B, Tab 2, Schedule 1, Section 5.4.1 and Exhibit B, Tab 2, Schedule 1, Section 5.4.6
Ch5, p11	Provide a snapshot of a distributor's capital expenditures over a 10-year period, including five historical years and five forecast years	Exhibit B, Tab 2, Schedule 1, Section 5.4.1
Ch5, p11	The entire cost of individual projects or programs allocated to one of the four investment categories based on the primary driver of the investment	Exhibit B, Tab 2, Schedule 1, Section 5.4.1.3
Ch5, p11	Completed Appendices 2-AA and 2-AB	Appendices 2-AA and 2-AB filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
Ch5, p11	Analysis of distributor's capital expenditure performance for the DSPs historical period - should include explanation of variances by investment category, including actuals v. OEB-approved amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP - explanation of variances that are much higher or lower than the historical trend	Exhibit B, Tab 2, Schedule 1, Section 5.4.1.2
Ch5, pp12	Analysis of distributor's capital expenditure performance for the DSPs forecast period; for investments that have a lifecycle >1yr, the proposed accounting treatment, including the treatment of the cost of funds for CWIP	Exhibit B, Tab 2, Schedule 1, Section 5.4.1.4
Ch5, p12	Analysis of capital expenditures in DSP forecast period v. historical	Exhibit B, Tab 2, Schedule 1, Section 5.4.1.5
Ch5, p12	Description of the impacts of capital expenditures on O&M for each year or statement that the capital plans did not impact O&M costs	Exhibit B, Tab 2, Schedule 1, Section 5.4.1.6
Ch5, p12	Statement that there are no expenditures for non-distribution activities in the applicant's budget	Exhibit B, Tab 2, Schedule 1, Section 5.4.1.7
Justifying Capital Expenditures		
Ch5, p12	Context on how overall capital expenditures over 5 years will achieve distributor's objectives; comment on lumpy investment years and rate impacts of capital investments in long term	Exhibit B, Tab 2, Schedule 1, Section 5.4.2
Material Investments		
For each project that meets materiality threshold set in Ch 2A or deemed by applicant to be distinct for any other reason, guidelines are:		
Ch5, p13	General information on the project/program - Need, scope, key project timings (incl. key factors that affect timing), total expenditures (inc. contributions and economic evaluation as per DSC, as applicable), comparative historical expenditures, priority, alternatives considered, cost/benefit of recommended alternative, description of the innovative nature of investment if applicable. -Where an investment within the five year forecast period involves a Leave to Construct approval, provide summary of the evidence (as available), for that investment consistent with Chapter 4 of the filing requirements	Exhibit B, Tab 2, Schedule 1, Attachment 1 through Attachment 9
Ch5, p13	Evaluation criteria and information requirements for each project/program - Demonstration of need, and may include the need to address safety, cyber security, grid innovation, environmental, statutory/regulatory obligations - Where investment substantially exceeds materiality - business case justifying expenditure, alternatives (including CDM activities if applicable), benefits for customers, impact on distributor costs -If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines	Exhibit B, Tab 2, Schedule 1, Attachment 1 through Attachment 9
Ch5, p14	Explanation of how innovative project is expected to benefit customers, such as improved reliability, enhanced customer services, CDM, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate	Exhibit B, Tab 2, Schedule 1, Attachment 1 through Attachment 9
Appendix A (if applicable)		
Ch5, Appendix A	Information on the capability of distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity	Not Applicable. See section 5.3.4 of the DSP (Exhibit B-02-01)
Ch5, Appendix A	In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable), includes: applications from renewable generators > 10 kW, number and MW of REG connections for forecast period, information from IESO and any other information about the potential for renewable generation in distributor's service area, capacity of Dx to connect REG, connection constraints	Not Applicable. See section 5.3.4 of the DSP (Exhibit B-02-01)

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
EXHIBIT 3 - CUSTOMER AND LOAD FORECAST		
Load Forecasts		
23	Weather normal load forecast provided	Not Applicable. See Exhibit C, Tab 1, Schedule 1 for rationale on why the load forecast is not weather normalized.
23	Table outlining any factors that influence the load forecast in distributor's service territory (e.g. demographics, customer composition etc.)	Exhibit C, Tab 1, Schedule 1
23	Explanation of the causes, assumptions and adjustments for the volume forecast, including all economic assumptions and data sources used (e.g. housing outlook & forecasts, other variables used in forecasting volumes)	Exhibit C, Tab 1, Schedule 1
23	Explanation of weather normalization methodology	Not Applicable. Remotes does not normalize its load forecast for weather (See Exhibit C, Tab 1, Schedule 1)
23	Completed Appendix 2-IB; the customer and load forecast for the test year entered on RRWF, Tab 10	Appendix 2-IB filed at Exhibit A, Tab 2, Schedule 2, Attachment 1 The customer/load forecast tabs of RRWF were not populated as these tabs were not specifically used by Remotes to derive customer rates.
23 & 24	Multivariate Regression Model -rationale to support change if the proposed model's methodology differs from the methodology used in the most recent load forecast; discussion of modelling approaches considered and alternative models tested -statistics of the regression equations coefficients and intercepts (e.g. t-stats, model statistics including R2, adjusted R2, F-stat, root-mean-squared-error), including explanation for any resulting non-intuitive relationships -explanation of weather normalization methodology (including if monthly HDD and/or CDD used they are based on either: 10 year avg. or proposed alternative approach with supporting evidence -definitions of HDD and CDD including: climatological measurement points and why appropriate as well as identification of base degrees -sources of data for endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable data used and source. Where a distributor has constructed the demand variable to model billed consumption on a class-specific basis, a full explanation of the approach used to pro-rate or interpolate non-interval data (i.e. if billing data are not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation of why the constructed demand series is suitable for modelling -any binary variables used must be explained and justified - the use of binary variables should be limited and overlap with other variables should be avoided -explanation of any specific adjustments made (e.g. to adjust for loss or gain of major customers or load, significant re-classifications of customers, etc.). Note locally purchased generation should be included in the total -description of how CDM impacts and other exogenous factors have been accounted for in the historical period, and how CDM impacts, including any CDM targets or forecasts in the bridge and test years, are factored into the test year load forecast -data and regression model and statistics used in customer and load forecast in Excel format	Not Applicable. Remotes does not use a multivariate regression model for load forecast.
25	NAC Model -rationale to support NAC methodology if the model use differs from the method used in the most recent load forecast -data supporting calculation of NAC values for each rate class -description of how CDM impacts and other exogenous factors have been accounted for in historical period and how CDM impacts, including any CDM targets or forecasts in the bridge and test years, are factored into test year forecast -discussion of weather normalization considerations	Not Applicable. Remotes does not use NAC model.
Incorporating CDM Impacts in the Load Forecast for Distributors		
25 & 26	Distributor may request approval for the use of the LRAMVA for a new CDM activity (a distribution-rate funded CDM activity or the Local Initiatives Program (LIP)), which would require establishing an LRAMVA threshold. If a distributor does request to establish an LRAMVA threshold, documentation of the CDM savings to be used as the basis for the 2023 LRAMVA threshold, and description of how these savings are aligned with the 2023 load forecast	Not Applicable. Remotes is not proposing a CDM adjustment to its load forecast.
26	If proposing different savings values for a CDM activity in the load forecast and LRAMVA threshold, description of rationale for these differences (e.g., timing of CDM activity, line loss factor, net-to-gross conversion factor)	Not Applicable. Remotes is not proposing a CDM adjustment to its load forecast.
Accuracy of Load Forecast and Variance Analyses		
26	Completed Appendix 2-IB (2-IA provides further instructions for filling out 2-IB)	Appendix 2-IB filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
26	For customer/connection counts: -identification as to whether customer/connection count is shown in year end or average format -year-over-year variances in changes of customer/connection counts with explanation for changes in the definition of, or major changes made in the composition of each customer class -explanations of bridge and test year forecasts by rate class -for last rebasing, variance analysis between last OEB-approved and actuals with explanations for material differences	Exhibit C, Tab 1, Schedule 1 and Appendix 2-IB filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
26 & 27	For consumption and demand: -explanation and details to support how kWh are converted to kW for applicable demand-billed classes -year-over-year variances in consumption (kWh) and demand (kW or kVA - the latter for demand billed rate classes) by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (comparison done for both historical actuals against each other and historical weather-normalized actuals over time) -explanations of the bridge and test year forecasts by rate class (and how these vary from or are trending from both historical actuals and from weather-normalized actuals) -for last rebasing variance analysis between the last OEB-approved and the actual results with explanations for material differences	Exhibit C, Tab 1, Schedule 1 Exhibit C, Tab 1, Schedule 3 and Appendix 2-IB
27	All data and equations used to determine customers/connections, demand and load forecasts provided in Excel format	Exhibit C, Tab 1, Schedule 2

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
EXHIBIT 4 - OPERATING EXPENSES		
Overview		
27	Brief explanation (quantitative and qualitative) of test year OM&A levels, how the distributor develops and receives approval of their OM&A budget, cost drivers and significant changes relative to historical and bridge years, trends in costs and relevant metrics including OM&A per customer (and its components) for the historical, bridge and test years, inflation rate assumed (if proposing different rate than IPI - provide explanation supporting proposal), business environment changes	Exhibit D, Tab 1, Schedule 1
OM&A Summary and Cost Driver Tables		
Inclusion of the following tables in evidence and all OM&A appendices filed:		
27	Summary of recoverable OM&A expenses; Appendix 2-JA	Appendix 2-JA filed at Exhibit A, Schedule 2, Tab 2, Attachment 1
27	Recoverable OM&A cost drivers; Appendix 2-JB	Appendix 2-JB filed at Exhibit A, Schedule 2, Tab 2, Attachment 1
27	OM&A programs table - Appendix 2-JC **or** OM&A by USoA Table - Appendix 2-JD	Appendix 2-JC filed at Exhibit A, Schedule 2, Tab 2, Attachment 1
28	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Appendix 2-L filed at Exhibit A, Schedule 2, Tab 2, Attachment 1
28	Distributors with 30k or more customers: present OM&A by program; Appendix 2-JC filed to provide OM&A details and variance analysis on a program basis. For each program, provide a definition of the USoA accounts included	Not Applicable, as Remotes is a distributor with less than 30K customers.
28	Distributors with less than 30k customers: option to file OM&A by program or USoA. If USoA chosen, 2-JD filed	Not Applicable, as Remotes is not electing to file Appendix 2-D
28	The table provided (2-JC or 2-JD) must reflect the entire OM&A amount proposed to be recovered through rates. Information provided for bridge and test years.	Appendix 2-JC filed at Exhibit A, Schedule 2, Tab 2, Attachment 1 will reflect the entire OM&A amount proposed to be recovered through rates
28	Appendix 2-JB populated to provide information on the cost drivers of OM&A expenses; 2-JA broken down into major categories	Appendix 2-JB filed at Exhibit A, Schedule 2, Tab 2, Attachment 1
28	Identification of change in OM&A in test year in relation to change in capitalized overhead	See Appendix 2-D for details, filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
OM&A Variance Analysis		
28	Re: 2-JC or 2-JD - variance analysis between: -test year vs last OEB approved -historical OEB-approved vs historical actuals (for the most recent historical OEB-approved year) -test year vs bridge year	Appendix 2-JC filed at Exhibit A, Tab 2, Schedule 2, Attachment 1 Exhibit D, Tab 1, Schedule 2 to Schedule 8
28 & 29	If OM&A expense detailed on USoA basis, variance analysis and explanation broken down by the five major OM&A categories as per 2-JA	Not Applicable, as Appendix 2-JD has been not filed.
29	Variance analysis includes explanation of whether the change was within the distributor's control or not - distributors encouraged to provide explanations for costs above the threshold which have impacted historical trend	Exhibit D, Tab 1, Schedules 1 through 8 and Exhibit D, Tab 2, Schedule 1
Workforce Planning and Employee Compensation		
29	Completed Appendix 2-K; information on labour and compensation includes total amount, whether expensed or capitalized	Appendix 2-K filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
29	If there are three or fewer employees in any category, aggregate with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees.	Not Applicable, as Remotes does not meet this requirement.
29	Description of proposed workforce plans, including compensation strategy and any changes from previous plan	Exhibit D, Tab 3, Schedule 1
29	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to FTEs and compensation. Explanation for all years includes: - Variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans - relevant studies (e.g. compensation benchmarking)	Exhibit D, Tab 3, Schedule 1
29	Details of employee benefit programs including pensions, OPEBs, and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital provided for the last OEB-approved rebasing application, and for historical, bridge and test years	Exhibit D, Tab 4, Schedule 1 Exhibit D, Tab 4, Schedule 1, Attachment 1
29	Most recent actuarial report; tax section of evidence agrees with this analysis	Not Applicable. The actuarial report is performed at the holding company level. Remotes does not impact the report. An actuarial account is not performed on Remotes.
29 & 30	For virtual utilities - Appendix K completed in relation to the employees of the affiliates who are doing the work of the regulated utility. Provide the status of pension funding and all assumptions used in the analysis	Not Applicable, as Remotes is not a virtual utility.

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
30	Indication if pension and OPEBs to be recovered using cash or accrual method; if cash method, sufficient supporting rationale and evidence for adopting cash method. If proposing to change the basis in which pension and OPEB costs are included in OM&A from last rebasing, quantification of impact of transition provided	Exhibit D, Tab 4, Schedule 1
	Shared Services and Corporate Cost Allocation	
30	Identification of all shared services among affiliates; identification of the extent to which the applicant is a "virtual utility" and justification of proposed shared services and cost allocation	All shared services between the affiliate and parent company are covered by an Affiliate Services Agreement. See Exhibit A, Tab 5, Schedule 2 and Exhibit D, Tab 1, Schedule 8
30	For shared services among affiliated entities: type of service provided or received, pricing methodology	Exhibit A, Tab 5, Schedule 2 and Exhibit D, Tab 1, Schedule 8
30	Allocation methodology for corporate services, list of shared services, list of costs and allocators and how the allocator was derived, any third party review of cost allocation methodology	Exhibit D, Tab 1, Schedule 8
30 & 31	Completed Appendix 2-N for service provided or received for historical actuals, bridge and test; including reconciliation with revenue included in Other Revenue	See Appendix 2-N filed at Exhibit A, Schedule 2, Tab 2, Attachment 1
31	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	Exhibit D, Tab 1, Schedule 8
31	Identification of any Board of Director costs for affiliates included in LDC costs	Not Applicable. There are no directly identifiable Board of Director costs for affliates included in LDC costs
	Non-Affiliate Services, One-Time Costs, Regulatory Costs	
31	Purchases of Non-Affiliated Services - copy of procurement policy (including information on signing authority, tendering process, non-affiliate service purchase compliance)	Exhibit A, Tab 5, Schedule 1
31	For material transactions not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	Not Applicable. See Exhibit A, Tab 5, Schedule 1
31	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test year. If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided	See Exhibit D, Tab 7, Schedule 1
32	Regulatory costs - breakdown of actual and anticipated regulatory costs including OEB cost assessments and expenses related to the CoS application (e.g. legal fees, consultant fees), information supporting incremental level of costs for preparation and review of current application, proposed recovery (i.e. amortized?), explanation if different than 5 years, completed Appendix 2-M	Exhibit D, Tab 1, Schedule 8 See Appendix 2-M filed at Exhibit A, Schedule 2, Tab 2, Attachment 1
	LEAP, Charitable and Political Donations	
32	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes. If proposing LEAP funding higher than 0.12%, details of demographics provided	Exhibit D, Tab 1, Schedule 8
32	For any charitable contributions claimed for recovery, detailed information provided	Exhibit D, Tab 7, Schedule 1
32	Confirmation that no political contributions have been included for recovery	Remotes has not requested the recovery of any political donations. See Exhibit D, Tab 7, Schedule 1
	Conservation and Demand Management	
33	Statement confirming that no costs for dedicated CDM staff to support IESO programs funded under the 2021-2024 CDM Framework are included in the revenue requirement	See Exhibit D, Tab 1, Schedule 6
33	If distributor plans to partner with the IESO for the LIP at the time of its cost of service application, description of proposed approach to partnership, including a forecast of LIP costs	Remotes does not have plans to partner with the IESO for the LIP at the time of its rebasing application.
	Funding Options for Future Conservation and Demand Management Activities	
33	If CDM activities included in COS where CDM activities expected to come into service during Price Cap IR term, identification of if costs of such CDM activities included in the revenue requirement, or if the distributor intends to propose treatment similar to an ACM for these future CDM activities	Not Applicable. Remotes is not requesting ratepayer funding for CDM program activities.
33	If the latter as noted above, supporting rationale provided (e.g., the preliminary cost information and ACM/ICM materiality threshold calculations to show that a similar capital project would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application)	Not Applicable. Remotes is not requesting ratepayer funding for CDM program activities.
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
	Capital Structure	
34	Use of most recent parameters issued by the OEB, subject to update if new parameters available prior to OEB decision. Alternatively - utility specific cost of capital with supporting evidence and justification	Exhibit E, Tab 1, Schedule 1
34	Completed Appendix 2-OA for last OEB approved and test years	Appendix 2-OA filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
34	Completed Appendix 2-OB for historical, bridge and test years	Appendix 2-OB filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
34	Explanation for any material changes in capital structure or material differences between actual and deemed capital structure including: retirement of debt or preference shares and buy-back of common shares; short-term debt, long-term debt, preference shares and common share offerings	Exhibit E, Tab 1, Schedule 1

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Cost of Capital (Return on Equity and Cost of Debt)		
	The following provided for each year:	
34	Calculation of cost for each capital component	See Appendix 2-OA and 2-OB filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
34	Profit or loss on redemption of debt, if applicable	Not Applicable, as Remotes did not have any redemption of debt
35	Copies of current promissory notes or other debt arrangements with affiliates	Not Applicable, as Remotes has no affiliates.
35	Explanation of debt rate for each existing debt instrument including an explanation on how the debt rate was determined and is in compliance with the policies documented in the 2009 Report or applicant's proposed approach	Exhibit E, Tab 1, Schedule 1
35	Forecast of new debt in bridge and test year - details including estimate of rate and other pertinent information (e.g. affiliated debt or third party?)	Remotes is not forecasting new debt in bridge and test years
35	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	Exhibit E, Tab 1, Schedule 1
35	Historic return on equity achieved	Not Applicable, As Remotes is 100% debt financed and does not earn a return on equity.
Not-for-Profit Corporations		
35	Requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	Exhibit E, Tab 1, Schedule 1
35	Statement as to whether the revenues derived from the return on equity component of the cost of capital is to be used to fund reserves or will be used for other purposes	Not Applicable, as Remotes does not have revenues derived from the return on equity component to fund reserves or other purposes.
35	If the revenues derived from the return on equity component will be used to fund reserves, specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied	Not Applicable, as Remotes does not have revenues derived from the return on equity component to fund reserves or other purposes.
35 & 36	If the revenues derived from the return on equity component will be used for other purposes, statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities); rationale provided supporting the use of the revenues in this manner. Also, governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities provided	Not Applicable, as Remotes does not have revenues derived from the return on equity component to fund reserves or other purposes.
36	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	Not Applicable, as there were no approved reserves from previous OEB decisions.
EXHIBIT 6 - REVENUE REQUIREMENT AND REVENUE DEFICIENCY OR SUFFICIENCY		
36	The following information must be provided in this exhibit (with cross references to where in the application further details can be found for each): -determination of net utility income, statement of rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency or sufficiency in revenue, gross deficiency or sufficiency in revenue	Exhibit F, Tab 1, Schedule 1
36	Revenue deficiency or sufficiency calculations net of electricity price differentials captured in the Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects, MIST meters) and for which disposition is not being sought in the application.	Exhibit F, Tab 1, Schedule 1
36	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Exhibit F, Tab 1, Schedule 1
37	Impacts of any changes in methodologies on deficiency/sufficiency and on individual cost drivers contributing to it	Exhibit F, Tab 1, Schedule 1
Revenue Requirement Work Form		
37	Completed RRWF. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Exhibit F, Tab 1, Schedule 1, Attachment 3 Completed up to Tab 9, as the remaining tabs were not specifically used by Remotes to derive customer rates.
37	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	Exhibit G, Tab 4, Schedule 1, Attachment 1
37	For revenues - calculation of bridge year forecast of revenues at existing rates; calculation of test year forecasted revenues at each of existing rates and proposed rates	Exhibit F, Tab 2, Schedule 1, Attachment 1

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Income Tax or PILs		
38	Detailed calculations of income tax or PILs as applicable. Completed version of the PILs model; derivation of adjustments for historical, bridge, test years	Remotes prepared its own PILs worksheet at Exhibit D, Tab 5, Schedule 1, Attachments 1 and 2
38	Supporting schedules and calculations identifying reconciling items	Exhibit D, Tab 5, Schedule 1, Attachments 1 and 2
38	Most recent federal and provincial tax returns	Exhibit D, Tab 5, Schedule 2, Attachments 1 and 2
38	Financial Statements included with tax returns if different from those filed with application	Not Applicable. Remotes' financial statements included with its tax returns were not different than those filed with this Application.
38	Calculation of tax credits; redact where required (filing of unredacted versions is not required)	No tax credits were estimated in the Remotes' Business Plan
38	Supporting schedules, calculations and explanations for other additions and deductions	Exhibit D, Tab 5, Schedule 1, Attachments 1 and 2
38	Completion of the integrity checks in the PILs Model	Remotes prepared its own PILs worksheet. See Exhibit D, Tab 5, Schedule 1
39	Accelerated CCA - full revenue requirement impact recorded in Account 1592 and the balance sought for review and disposition, method used in calculating the revenue requirement impact recorded in Account 1592, detailed calculations by year for the full revenue requirement impact recorded in Account 1592	Exhibit A, Tab 2, Schedule 1, and Attachment 4 Exhibit D, Tab 5, Schedule 1, and Attachments 1 and 2
39 & 40	May propose smoothing mechanism proposal	Not Applicable, as Remotes is not proposing a smoothing mechanism proposal
Other Taxes		
40	Excluded from all OM&A totals. Explanation of how these tax amounts are derived	Exhibit D, Tab 1, Schedule 1 Exhibit D, Tab 6, Schedule 1
Non-recoverable and Disallowed Expenses		
40	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Exhibit D, Tab 5, Schedule 1
Other Revenue		
40	Completed Appendix 2-H, including the breakdown of each account showing the components of each	Appendix 2-H filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
40	For each other distribution revenue account: -comparison of actual revenues for historical years to forecast revenue for bridge and test year, including explanations for significant variances year-over-year -revenue from any new proposed specific service charges, changes to rates, or new rules for applying existing specific service charges (incl. any credits to customers) -revenue from affiliate transactions, shared services, or corporate cost allocation. For each affiliate transaction identification of service, the nature of service provided, accounts used to record revenue, and costs to provide service -revenue from affiliate transactions recorded in Account 4375 -expenses from affiliate transactions recorded in Account 4380	Exhibit F, Tab 3, Schedule 1 Exhibit D, Tab 1, Schedule 8 Note: Remotes is not proposing any new specific charges.
41	Balances recorded in Account 4375 and Account 4380 reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Allocation for the three historic years, the bridge year and the test year. Any differences must be reconciled	Appendix 2-N filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
41	Revenue related to microFIT recorded as revenue offset in Account 4235 and not included as part of base revenue requirement	Appendix 2-H filed at Exhibit A, Tab 2, Schedule 2, Attachment 1
41	Transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business and compliance with article 340 of APH; explanations for any deviations	Remotes only performs work with Acronym (Telecom services), which is a non-regulated affiliate. All costs are at fair value under the SLA process as described in Exhibit D, Tab 1, Schedule 8.
41	Identification of any discrete customer groups that may be materially impacted by changes to other rates and charges.	Exhibit A, Tab 1, Schedule 3
EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
42	Completed cost allocation study using the OEB-approved methodology or the distributor's study and model reflecting forecasted test year loads and costs and supported by appropriate explanations and live Excel spreadsheets; sheets 11 and 13 of the RRWF complete	Not Applicable, because the methodology for setting rates for Remotes customers is established under O.Reg 442/01
42	Description of weighting factors, rationale for use of default values (if applicable)	Not Applicable, because the methodology for setting rates for Remotes customers is established under O.Reg 442/01
42	If distributor is choosing to use the same weightings as its previous rebasing application, a reference to the previous application provided	Not Applicable, because the methodology for setting rates for Remotes customers is established under O.Reg 442/01
42	Complete live Excel cost allocation model, whether using the OEB-issued one or a different model. If using the OEB-issued model, Input sheet I.2, cells c15 and c17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information.	Not Applicable. The methodology for setting rates for Remotes customers is established under O.Reg 442/01

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Load Profiles and Demand Allocators		
43	Updated all classes' load profiles and updated demand allocators	Not Applicable. Remotes does not have demand charges.
43	Discussion of how load profiles have been normalized for weather and any notable events impacting usage patterns	Not Applicable. Remotes does not have demand charges.
43	If multivariate regression used, the following provided: -statistics of regression equation(s) coefficients and intercept -explanation of the weather-normalization methodology including: relationship between demand and Heating and/or Cooling requirements, determination of normal weather: the hourly for daily Heating and/or Cooling required -sources of data used for both endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable, data used and the soruce of the data provided -explanation of any specific adjustments made (e.g. to address gaps in historical meter data)	Not Applicable. Remotes does not use a multivariate regression model for load forecast.
43	Data and regression model and statistics used in customer and load forecast provided in Excel format (includes showing the derivation of any constructed variables)	Exhibit C, Tab 1, Schedule 2
44	Demand Allocators: spreadsheet and a description with calculations to show how demand allocators are derived from the historical weather normal or weather actual load profiles	Not Applicable - Remotes does not use demand allocators.
44	Historical Average: Where the annual demand allocators are based on weather actual load profiles, at least three, and ideally five years of historical data should be used to perform weather normalization. Where the annual demand allocators are based on weather normalized load profiles, fewer years may be used	Not Applicable as Remotes does not normalize for weather as explained in Exhibit C, Tab 1, Schedule 1
44 & 45	Host Distributor only - evidence of consultation with embedded Dx - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges levied); include in cost allocation study and RRWF - if embedded Dx billed as GS customer - include with the GS class in cost allocation model and the RRWF. Provide cost of serving, load served, asset ownership information, distribution charges levied, appropriateness of rates for the GS class recovering costs of providing low voltage dx services to embedded distributor(s). Completed Appendix 2-Q.	Not Applicable. Remotes does not have any embedded distributors
45	microFIT - if the applicant believes that it has unique circumstances which would justify a different rate than the generic rate, documentation to support rate must be provided	Not Applicable. Remotes does not have any micro FIT customers and is not proposing changes
46	Standby Rates - distributors should request approval for its standby rates to be made final and provide evidence confirming that they have advised all affected customers of the proposal. A distributor that seeks changes to its standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s).	Not Applicable. Remotes does not charge standby rates
46	If new customer class or changing definition of existing classes, rationale and restatement of revenue requirement from previous cost of service	No new rate classes are proposed
46	If eliminating or combining customer classes, rationale and restatement of revenue requirement from previous cost of service	Not Applicable. No changes to customer classes proposed
Class Revenue Requirements		
46 & 47	To support a proposal to rebalance rates, information on the revenue by class that would apply if all rates were changed by a uniform percentage provided. Ratios compared with the ratios that will result from the rates being proposed by the distributor.	Not Applicable. No proposal to rebalance rates
Revenue to Cost Ratios		
47 & 48	If R:C ratios outside dead band - cost allocation proposal to bring them within the OEB-approved ranges provided. In making any such adjustments, potential mitigation measures addressed if the impact of the adjustments on the rates of any particular class or classes is significant.	The methodology for setting rates for Remotes customers is established under O.Reg 442/01
48	If distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided	Not Applicable. No proposal to rebalance rates.
48	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	Not Applicable. The methodology for setting rates for Remotes customers is established under O.Reg 442/01
EXHIBIT 8 - RATE DESIGN		
48	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places; if departing from this approach, explanation provided as to why necessary and appropriate	Exhibit F, Tab 2, Schedule 1
Fixed Variable Proportion		
48	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V for each rate class with supporting info -Proposed F/V for each rate class with explanation for any changes from current proportions -Table comparing current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	The methodology for setting rates for Remotes customers is established under O.Reg 442/01. Because Remotes' rates include both generation and distribution, Remotes is not planning to move to a fixed monthly charge. See Exhibit F-02-01
RTSRs		
49	Completed RTSR Model in Excel	Not Applicable. See rationale in Exhibit A, Tab 2, Schedule 2
49	RTSR information consistent with working capital allowance calculation; explanation for any differences	Not Applicable, as the RTSR Model is not applicable to Remotes.
Retail Service Charges		
49	Distributors that are still using the Retail Service Costs Variance Accounts (RCVAs) or Retail Service Charges Incremental Revenue Sub-account are to dispose of the balances and the OEB will eliminate the sub-accounts. Distributors should forecast retail services revenues based on the updated charges and include the costs of providing retail services in revenue requirement	Not Applicable, as Remotes has not applied the RCVA charges to customers, and do not have RCVA accounts.

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Regulatory Charges		
50	If applying for a rate other than the generic rate set by the OEB, distributors must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate	Not Applicable. This does not apply to Remotes.
Specific Service Charges		
50	If requesting new specific service charge or a change to the level of an existing charge, description of the purpose of charge, or reason for change to an existing charge; calculations to support charges	Not Applicable, as Remotes is not proposing new or revised specific service charges
50	Identification in the Application Summary all proposed changes that will have an impact on customers, including changes to other rates and charges that may affect a discrete group; identification of specific customers or customer groups impacted by each proposal	Exhibit A, Tab 1, Schedule 2
50	Calculation of charge includes: direct labour, labour rate, burden rate, incidental, other	Not Applicable, as Remotes is not proposing new charges
51	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions recovered from these rates from last OEB-approved year to most recent actuals and the revenue or capital contributions forecasted for the bridge and test years. A proposal and explanation as to whether these charges should be included on tariff sheet	All rates and charges appear on the Tariff Sheet.
51	Revenue from SSCs corresponds with Operating Revenue evidence	Exhibit F, Tab 3, Schedule 1
Wireline Pole Attachment Charge		
51	Distributor disposing of Wireline account may forecast the balance up to the effective date of new rates, provided it can do so with reasonable accuracy, and the OEB may consider disposing of the forecasted amount	Not Applicable, as Remotes has not applied the board-approved wireline pole attachment charge
Low Voltage Service Rates		
If the distributor is fully or partially embedded, information on the following must be provided:		
52	Forecast LV Cost	Remotes is not a host nor an embedded distributor.
52	Actual LV Cost for the last three historical years along with bridge and test year forecasts; year-over-year variances and explanations for substantive changes in costs over time up to and including test year forecast	Remotes is not a host nor an embedded distributor.
52	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	Remotes is not a host nor an embedded distributor.
52	Allocation of forecasted LV cost to customer classes (typically proportional to Tx connection revenue)	Remotes is not a host nor an embedded distributor.
52	Proposed LV rates by customer class	Remotes is not a host nor an embedded distributor.
Smart Meter Entity Charge		
53	Current OEB-approved SMC charged until the OEB approved any updated SMC	Not Applicable. Rates are bundled and established through RRRP Regulation, and does not have an approved SMC.
Loss Factors		
53	Proposed SFLF and Total Loss Factor for test year	Remotes has no approved loss factors.
53	Statement as to whether LDC is embedded including whether fully or partially	Exhibit A, Tab 2, Schedule 1, Legal Form of Application
53	Study of losses if required by previous decision	Remotes has not been directed to complete a study of losses in a previous decision.
53	3-5 years of historical loss factor data - Completed Appendix 2-R	Remotes has no approved loss factors.
53	If proposed distribution loss factor >5%, explanation for level of losses, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward	Remotes has no approved loss factors.
53	Explanation of SFLF if not standard	Remotes has no approved loss factors.
53	Reconciliation between the application and RRR filing	Remotes has no approved loss factors.
Tariff of Rates and Charges		
53 & 54	Current and proposed Tariff of Rates and Charges - **must be filed in Excel format and PDF format** Explanation and support of each change in the appropriate section of the application	Exhibit G, Tab 3, Schedule 1 Exhibit G, Tab 4, Schedule 1
54	Completed Bill Impacts Model	Exhibit G, Tab 4, Schedule 1, Attachment 1
54	Explanation of changes to terms and conditions of service if changes affect application of rates and rationale behind those changes	Not Applicable; no changes to terms and conditions of service that affect application of rates
54	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	Not Applicable; regulatory charges not currently applicable to Remotes
Revenue Reconciliation		
54	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	Exhibit F, Tab 2, Schedule 1; reconciliation to total revenue requirement is not applicable.
54	Completed RRWF - Sheet 13 (table reconciling base revenue requirement against revenues recovered through proposed rates)	Remotes has provided its own version of the RRWF at Exhibit F, Tab 1, Schedule 1, Attachment 3
Bill Impact Information		
54	Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	Remotes' rates are set by Regulation. A rate model is provided at Exhibit G, Tab 4, Schedule 1, Attachment 1.
54	Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant	Exhibit G, Tab 2, Schedule 1
55	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory for each class	Exhibit G, Tab 2, Schedule 1

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
55	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	Not Applicable; Remotes is not aware of examples of customers with unique consumption for which bill impacts should be shown
Rate Mitigation		
55	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification for mitigation measure including reasons if no mitigation proposed, other relevant information. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	Not Applicable, as there are no total bill increases that are greater than 10%
Rate Harmonization Mitigation Issues		
56	If part of a MAADs transaction, and rate harmonization plan not yet approved by the OEB, a rate harmonization plan must be filed	Not Applicable, as there are no rate harmonization issues
56	Plan includes a detailed explanation and justification for the implementation plan, and an impact analysis	Not Applicable, as there are no rate harmonization issues
56	If impact of COS increases and harmonization effects result in total bill increases for any customer class exceeding 10%, discussion of proposed measures to mitigate increases in its mitigation plan, or justification provided as to why mitigation is not required	Not Applicable, as there are no rate harmonization mitigation issues
56	Migration plan that includes fully harmonizing rates that is to be accomplished over more than one year must be supported by a detailed plan for accomplishing this during the subsequent Price Cap IR period	Not Applicable, as there are no rate harmonization mitigation issues
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
56	Table showing all DVAs not disposed of yet, showing principle and interest/carrying charges, total balance for each account, and whether account being proposed for disposition	Exhibit H, Tab 1, Schedule 1
56	If applicable, description of DVAs that were used differently than as described in the APH, relevant accounting order or other OEB document	Remotes accounts are consistent with the APH.
56	Completed DVA continuity schedule for period from last disposition to present - live Excel format. Continuity schedule must show separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all outstanding DVAs. The opening principal amounts and interest amounts for Group 1 and 2 balances, shown in the DVA Continuity Schedule, must reconcile with the last applicable approved closing balances.	Due to the unique nature of the RRRP Account, detailed reconciliation tables are provided in Exhibit H, Tab 2, Schedule 1, Attachments 1 to 6.
57	Confirmation of use of interest rates established by the OEB by month or by quarter for each year; most recently published rate used for future periods	Not Applicable. Remotes does not apply interest.
57	Explanation if account balances in continuity schedule differs from trial balance reported through RRR and documented in AFS - included in tab Appendix A of DVA schedule. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the RRR is to be provided in the continuity schedule	Account balances reflect the trial balance, therefore there are no differences between RRR 2.1.5.4 and the RRRP balance documented in the AFS.
57	Identification of any Group 2 accounts proposed to continue/discontinue going forward, with explanation	Not Applicable. Remotes does not have Group 2 accounts.
57	Identification of any new accounts or sub-accounts, and justification; must correspond with info in Exhibit 1	Remotes is not requesting any new accounts.
57	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis - the OEB expects that no adjustment will be made to any deferral and variance account balances previously approved by the OEB on a final basis. If any adjustments have been made, explanation for the nature and the amount of the adjustment(s), and appropriate supporting documentation, under a section titled "Adjustments to Deferral and Variance Accounts"	There were no adjustments made to account balances previously approved by the Board.
57	Statement confirming distributor has complied with OEB guidance of February 21, 2019 on the accounting for Accounts 1588 and 1589	Not Applicable. Remotes does not have Accounts 1588 and 1589.
Disposition of Deferral and Variance Accounts		
57	For accounts as identified in summary table not being proposed for disposition, explanations provided	Not Applicable. Remotes is seeking disposition of all the accounts noted in Exhibit H, Tab 1, Schedule 1.
58	For any distributor-specific accounts requested for disposition, supporting evidence showing how the annual balance is derived and the relevant accounting order	Not Applicable. Remotes does not have any distributor-specific accounts.
58	If proposing to allocate a DVA which the OEB has not established an allocator, proposed allocation based on cost driver must be provided with justification; indication of proposed billing determinants, including charge type for recovery purposes and included in cont. schedule	Not Applicable. Remotes is seeking recovery of the DVA balance through RRRP, as noted in Exhibit H, Tab 1, Schedule 1.
58	Propose rate riders that dispose of the balances. If the applicant is proposing an alternative recovery period other than one year, explanation provided	Not Applicable. Remotes is seeking recovery of the DVA balance through RRRP, as noted in Exhibit H, Tab 1, Schedule 1.
58	Rate riders where volumetric rider is $0.0000 for one or more classes not included in the tariff for those classes	
Disposition of Accounts 1588 and 1589		Not Applicable. Remotes does not have activity in Accounts 1588 or 1589. Remotes customers do not pay Global Adjustment. As described in Exhibit A, Tab 2, Schedule 1, Remotes is seeking an exemption from the use of these accounts.
55	If a distributor has not implemented OEB's February 21, 2019 accounting guidance, indication that this is the case	
55	Indication of the year in which Account 1588 and Account 1589 balances were last approved for disposition, and whether the balances were approved on an interim or final basis. If the balances were last disposed on an interim basis, indicate the year in which balances were last disposed on a final basis	
59	If requesting final disposition of balances for the first time following implementation of the accounting guidance, confirmation that accounting guidance has been implemented fully effective January 1, 2019	
59 & 60	In order to request for final disposition of historical balances as part of the current application, confirmation that these balances have been considered in the context of the accounting guidance and provide a summary of the review performed. Discussion on the results of the review, any systemic issues noted, and whether any material adjustments to those balances have been recorded. Summary and description of each adjustment made to the historical balances provided	
60	GA Analysis Workform (in live Excel format) for each year that has not previously been approved by the OEB for disposition. If the distributor is adjusting the Account 1589 GA balance that was previously approved on an interim basis, the GA Analysis Workform must be completed from the year after the distributor last received final disposition for Account 1589	

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
60	As described in Note 5 in the GA Analysis Workform, reconciliation of any discrepancy between the actual and expected balance by quantifying differences (e.g. true-ups between estimated and actual costs and/or revenues). Any remaining unexplained discrepancy that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation.	
60	Completed reasonability test for the balance in Account 1588. The reasonability test is included in the GA Analysis Workform.	
	Disposition of CBR Class B Variance	
60 & 61	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. Must be disposed over one year. - In the DVA continuity schedule, indication whether any Class A customers served during the period where Account 1580 CBR Class B sub-account balance accumulated. In the event that the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580 CBR Class B sub-account will be added to the Account 1580 – WMS control account to be disposed through the general purpose Group 1 DVA rate riders - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance	Not Applicable: Remotes does not have activity in Account 1580 sub-account CBR Class B.
	Disposition of Account 1595	
61	Applicants are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year once, on a final basis	Remotes is seeking disposition of the non-material residual balance in its Rate Rider for Recovery of COVID-19 Forgone Revenue through RRRP, as noted in Exhibit H, Tab 1, Schedule 1.
62	Explanation for any material residual balances being proposed for disposition, including quantifying significant drivers of the residual balance	
	Disposition of Retail Service Charges	
62	If there is a balance in 1518 or 1548, distributor must: - confirm variances are incremental costs of providing retail services; identify drivers for balances - provide schedule identifying all revenues and expenses listed by USoA that are incorporated into the variances - state whether Article 490 of APH has been followed; explanation if not followed	Not Applicable. Remotes does not have activity in 1518 or 1548 as Remotes is exempt from the Retail Service Code.
62 & 63	The OEB established a new variance account for electricity distributors that no longer used the RCVAs. The balance in the account would be refunded to ratepayers in a future rate application, and the new account subsequently closed. Distributors may forecast a balance up to the effective date of new rates and the OEB may consider disposing of the forecasted amount	
	Disposition of Account 1592, Sub-account CCA Changes	
63	Calculations for accelerated CCA differences per year, based on actual capital additions. Calculations include: underpreciated capital cost continuity schedules for each year itemized by CCA class, calculated PILs/tax differences, grossed-up PILs/tax differences. other applicable information	Not Applicable: The Board approved Remotes exemption to this account in a letter entitled "Hydro One Remote Communities Inc. (Remotes) Exemption Request from the Ontario Energy Board's CCA and Tax Related Accounting Direction" dated April 1, 2020; as provided in Exhibit A, Tab 2, Schedule 1, Attachment 4.
63	Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable	
63	Reconciliation of these amounts to the amounts presented in Account 1592 sub-account CCA changes in the DVA continuity schedule	
	Disposition of Account 1509 Impacts Arising from the COVID-19 Emergency	
64	If requesting disposition of any amounts related to the COVID-19 Account, the following, at a minimum is to be provided: -Discussion regarding the interactions between the COVID-19 Account and other existing generic or utility-specific accounts, including a determination that there is no double-counting between multiple ratemaking mechanisms -Calculation showing that the distributor passes the ROE-based means tests, including limitations on recoveries when various ROE thresholds are reached, and that the appropriate recovery rates for each sub-account have been applied -Supporting calculations for the annual amounts recorded in each of the sub-accounts, including the methodology used to measure incremental costs and savings, as applicable - Discussion of causation, materiality, prudence of any amounts recorded in the sub-accounts, including all identified savings and cost reductions -Discussion of whether the distributor would be able to reasonably forecast any further entries in the account, up to the effective date of the new rates, so that the account may be disposed in its entirety in the current proceeding (and whether the distributor would be amenable to such an approach) -Statement confirming proposed discontinuation of the COVID-19 Account, effective the same date as the new rates. If this is not the case, supporting rationale provided	Not Applicable. Remotes is not seeking disposition of Account 1509 arising from the COVID-19 emergency, consistent with its approach to recover all COVID-19 related costs to date through RRRP, as described in Exhibit A, Tab 1, Schedule 9.
	Establishment of New Deferral and Variance Accounts	
64 & 65	If new DVA - evidence provided which demonstrates that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order	Remotes is not requesting any new DVAs.

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Lost Revenue Adjustment Mechanism Variance Account		
65	In preparing claims related to disposition of outstanding LRAMVA balances, distributors may seek to claim savings from Conservation First Framework (CFF) programs, and from programs they delivered through the Local Program Fund that was part of the Interim Framework. Distributors should provide sufficient supporting documentation on project savings to support their claim	
Disposition of LRAMVA		
66	Disposition sought of all outstanding LRAMVA balances related to previously established LRAMVA thresholds	
67	Current version of LRAMVA Work Form (Excel)	
An application for lost revenues should include:		
67	Final Verified Annual Reports if claiming lost revenues from savings from CDM programs delivered in 2017 or earlier	
67	Participation and Cost reports and detailed project level savings in Excel format made available by the IESO	
67	Other supporting evidence with an explanation and rationale should be provided to justify the eligibility any other savings from a program delivered by a distributor after April 15, 2019	
67 & 68	Personal information and commercially sensitive information removed, or if required, filed in accordance with OEB's Rules of Practice and Procedure and Practice Direction on Confidential Filings	
An application for lost revenues should also provide:		
68	Statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition	
68	Statement confirming LRAMVA based on verified savings results supported by the distributors final Verified Annual Reports and Persistence Savings Report (both filed in Excel format)	
68	Statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation	
68	Summary table with principal and carrying charges by rate class and resulting rate riders	
68	Statement confirming recovery period; rationale provided for disposing the balance in the LRAMVA if one or more classes do not generate significant rate riders	
68	Details related to the approved CDM forecast savings from the last rebasing application	
69	Statement explaining how rate class allocations for actual CDM savings were determined by class and program for each year	
69	Statement confirming whether additional documentation was provided in support of projects that were not included in distributors final Verified Annual Reports and Participation and Cost Reports (Tab 8 of LRAMVA Work Form as applicable)	
69	If not already filed in support of a previous LRAMVA application, provide Participation and Cost Reports and detailed project level savings files made available by the IESO and/or other supporting evidence to support the clearance of energy- and/or demand-related LRAMVA balances where final verified results from the IESO are not available - filed in Exel format	
69	For a distributor's street lighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: explanation of the methodology to calculate street lighting savings, confirmation whether the street lighting projects received funding from the IESO and the appropriate net-to-gross assumption used to calculate streetlighting savings	
For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information:		Not Applicable. Remotes does not have a LRAMVA.
69	Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application	
69	Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed	
69	Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings	
69	Confirmation that the distributor has received reports from the participating municipality that validate the number and type of bulbs replaced or retrofitted through the IESO program	

July 20, 2016

2023 Cost of Service Checklist

Hydro One Remotes Communities Inc.

EB-2022-0041

Date: August 31, 2022

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
69 & 70	A table, in live Excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade project (including data on number of bulbs, type of bulb replaced or retrofitted, average demand per bulb)	
For the recovery of lost revenues related to demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information:		
70	The third party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different than the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate	
70	Rationale for net-to-gross assumptions used	
70	Breakdown of billed demand and detailed level calculations in live Excel format	
For program savings up to December 31, 2022 for projects completed after April 15, 2019, a distributor should provide the following:		
70	Related to CFF programs: explanation as to how savings have been estimated based on the available data (i.e., IESO's Participation and Cost Reports) and/or rationale to justify the eligibility of the program savings	
70	Related to programs delivered by a distributor through the Local Program Fund under the Interim CDM Framework: explanation and rationale to justify the eligibility of the additional program savings	
Continuing Use of the LRAMVA for New CDM Acitivities		
70	Indication of whether distributor is requesting the continued use of the LRAMVA for one or more activities related to distribution rate-funded CDM activities or LIP activities	
70	If requesting access to, or use of, the LRAMVA for these activities, demonstration of need for the LRAMVA (or similar mechanism), the proposed LRAMVA threshold, how it intends to support the tracking of lost revenues, and the nature of the documentation that it proposes to provide at the time of LRAMVA disposition	
70 & 71	Allocation of the CDM savings for both the LRAMVA and the load forecast provided by customer class and for both kWh and, as applicable to a customer class, kW. Document how CDM savings will be tracked and reported in order to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs	
Appendix A Cost of Eligible Investments for the Connection of Qualifying Generation Facilities		
Appendix A	If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09	Remotes recovers all costs through INAC. See Exhibit A, Tab 3, Schedule 3 for details of the REINDEER program.
Appendix A	Appendices 2-FA through 2-FC identifying all eligible investments for recovery	Not Applicable, as Remotes is not applying for provincial funding for renewable generation investments.
Appendix A	For distributors that are already receiving rate protection as a result of a previous application the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for input into Appendices 2-FA through 2-FC. This would generate a new up-to-date rate protection amount for the test year and beyond, which will be subject to the materiality threshold	Not Applicable, as Remotes is not applying for provincial funding for renewable generation investments.

Ontario Energy Board | Commission de l'énergie de l'Ontario

BY EMAIL

April 1, 2020

Ms. Joanne Richardson
Director – Major Projects and Partnerships, Regulatory Affairs
Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto ON M5G 2P5
regulatory@hydroone.com

Dear Ms. Richardson:

Re: Hydro One Remote Communities Inc. (Remotes) Exemption Request from the Ontario Energy Board's CCA and Tax Related Accounting Direction

This letter is in response to your letter to the Ontario Energy Board (OEB) dated February 26, 2020, requesting an exemption from the OEB's Capital Cost Allowance (CCA) and Tax Related Accounting Direction, specifically related to the accelerated investment incentive (AII) program.[1] Remotes has requested that the exemption be retrospectively approved to November 20, 2018 and continue until Remotes' next rebasing application approval.

In its letter, Remotes stated that the accounting direction will have no impact on Remotes' financial results because of the unique nature of how Remotes is operated (i.e. a break-even basis). Remotes also stated that the accounting direction would add additional complexity, effort and cost to implement and administer.

The OEB agrees with Remotes that if the new accounting direction was implemented it would have no impact on the utility's financial results and also would result in additional effort and cost. The OEB grants Remotes' request. However, the OEB notes that this request will be effective to December 31, 2027, when the AII program is expected to end, unless directed otherwise by the OEB as part of Remotes' next rebasing application.

[1] OEB Letter, *Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance*, July 25, 2019

The OEB's policies state that for rate-setting purposes, distributors are expected to take the maximum income tax deductions allowed.[2] The OEB expects Remotes to reflect the maximum CCA deductions under the AII program on its tax returns filed with the Canada Revenue Agency, in order to minimize its taxes payable.

Yours truly,

Original Signed By

Christine E. Long
Registrar and Board Secretary

---

[2] *Filing Requirements For Electricity Distribution Rate Applications - 2018 Edition for 2019 Rate Applications - Chapter 2 Cost of Service*, July 12, 2018, page 35

TABLE OF OEB WORK FORMS AND CHAPTER 2 APPENDICES

As discussed in Exhibit A, Tab 3, Schedule 1, Remotes is unique in terms of its operating characteristics, and has been approved to recover costs from the Rural or Remote Electricity Rate Protection (RRRP) fund. Many of the issues and OEB work forms that apply to other electricity distributors do not apply to Remotes for the reasons set out below.

Remotes Chapter 2 appendices are filed in their entirety as Exhibit A, Tab 2, Schedule 2, Attachment 1.

CHAPTER 2 APPENDICES

OEB Appendix Number	OEB Appendix Title	Reason not Provided
2-BB	Service Life Comparison	Remotes has used a custom study to service lives by asset group. App 2-BB is not applicable, as there are no changes in asset service lives since last rebasing.
App 2-FA to 2-FC	Renewable Generation	Remotes is not seeking to apply for provincial funding of REG investments in this Application.
App 2-I	CDM adjustment	Remotes does not adjust the load forecast to account for CDM.
App 2-R	Loss factors	Remotes is not billed directly by the IESO at this time, so it has historically not requested approval of a loss factor. Remotes does serve the community of Pikangikum via grid connection through a modified transmission connection agreement with Networks. In this Application, Appendix 2-R (Exhibit A, Tab 2, Schedule 2, Attachment 1) has been completed based on information available to date as Remotes has been delivering power to one community. However, as loss factors are embedded in the cost of power calculation (Exhibit D, Tab 1, Schedule 7, Attachment 1) and cost of power flows through the RRRP, Remotes does not need to separately bill its customers for the line losses on power delivered. Despite completion of this form, Remotes is not requesting approval of a loss factor in this Application. Please see further details in the Appendix 2-R tab within the Chapter 2 Appendices.
App 2-Q	Cost of serving embedded distributors	Remotes is neither a host or embedded distributor
App 2-Z	Commodity expense	Remotes is exempt from the Standard Service Supply Code and Remotes' customers are not part of the Regulated Price Plan. Rates are bundled and established through RRRP Regulation. As such, Remotes does not have RPP or non-RPP customers. Now with an increasing number of customers being grid connected, Remotes will be billed for the cost of power by the IESO after August 2022, but as the cost of power is not split up between RPP and non-RPP customers, Remotes has provided an equivalent form at Exhibit D, Tab 1, Schedule 7, Attachment 1.

OEB COST OF SERVICE MODELS

OEB Model	Location in Application or Reason not Provided
Revenue Requirement Work Form	Exhibit F, Tab 1, Schedule 1, Attachment 3
Tariff Schedule and Bill Impact Model	Exhibit G, Tab 4, Schedule 1, Attachment 1
Income Tax/PILs Work Form	Remotes prepared its own PILs worksheet at Exhibit D, Tab 5, Schedules 1, Attachments 1 and 2
DVA Continuity Schedule	Consistent with the approach taken in EB-2017-0051, Remotes has prepared its own reconciliation schedules for its Rural and Remote Rate Protection Variance Account (RRRPVA) as documented in Exhibit H, Tab 2, Schedule 1, Attachments 1 to 6.
RTSR Work Form for Electricity Distributors	Remotes is exempt from the Retail Service Code, and thus the RTSR Work form does not apply to Remotes.
Cost Allocation Model	Remotes rates are set pursuant to O. Reg 442/01, thus rates are not determined from the cost allocation model.
GA Analysis Workform	Not Applicable. Remotes customers do not pay Global Adjustment, and as such Remotes does not have activity in Account 1589.
Lost Revenue Adjustment Mechanism Variance Account (LRAMVA) Work Form	Not Applicable. Remotes has not been subject to the Board's CDM Code, and Remotes does not have activity in LRAMVA.
ACM Workform	Currently, Remotes is not requesting ACM treatment for its projects included in the DSP. In the event there are any further delays affecting in the actual in-servicing date of the Beaverhall facility expansion/relocation (DSP Attachment 9), Remotes can consider the applicability of requesting advanced capital approval of this project through an ACM. Given the circumstance in which Remotes recovers its revenues through the RRRP for any amounts beyond the average customer rates specified in Exhibit F, Tab 2, Schedule 1, Attachment 1, the ACM work form may not be the most suitable option for Remotes. However, Remotes is open to seeking guidance from the OEB on the appropriate treatment for advanced capital funding should the need arise.

This page has been left blank intentionally.

Ontario Energy Board

Chapter 2 Appendices
Filing Requirements for Electricity Distribution Rate Applications

Version 1.0 (2023)

Utility Name	Hydro One Remote Communites Inc.
Assigned EB Number	EB-2022-0041
Name of Contact and Title	
Phone Number	
Email Address	
Test Year	2023
Bridge Year	2022
Last Rebasing Year	2018
Identify the accounting standard used for the test year	USGAAP
Did Hydro One Remote Communites Inc. update its depreciation and capitalization policies?	
If "yes" to cell E34, were the changes in policies reflected in a prior rebasing application?	
When did Hydro One Remote Communites Inc. update its actual depreciation and capitalization policies?	**January 1**
Identify the year the applicant adopted IFRS for financial reporting purposes	
Is Hydro One Remote Communites Inc. applying for cost recovery for the test and/or future year(s) for Green Energy initiatives?	No
Is Hydro One Remote Communites Inc. an embedded distributor?	No

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Appendix 2-AA
Capital Projects Table
in $K

Projects	2018	2019	2020	2021	2022 Bridge Year	2023 Test Year
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
SYSTEM ACCESS						
New Customer Connections & Service Upgrades						
New Customer Connections & Service Upgrades	775	1,248	783	1,339	997	1,113
Contributions and Removals	-757	-1,239	-780	-1,306	-997	-1,113
New Customer Connections & Service Upgrades Sub-tota	18	9	3	33	0	0
Service Cancellations						
Service Cancellations	70	80	67	68	78	86
Removals	-70	-80	-67	-68	-78	-86
Service Cancellations Sub-Total	0	0	0	0	0	0
Fixed Price Layouts						
Fixed Price Layouts	170	220	344	416	293	325
Contributions	-78	-133	-113	-147	-224	-273
Fixed Price Layouts Sub-Total	92	87	231	269	69	52
Distribution System Upgrades						
Marten Falls DGS - Line Relocate	0	0	0	129	0	0
Contributions	0	0	0	-131	0	0
Distribution System Upgrades Sub-Total	0	0	0	-2	0	0
Distribution Development						
Wholesale Metering Cluster	0	0	0	106	1,394	3,644
SYSTEM ACCESS Sub-Total	**110**	**96**	**234**	**406**	**1,463**	**3,696**
SYSTEM RENEWAL						
Distribution Development						
Distribution System Improvements	267	235	1,048	776	592	609
Contributions and Removals	-217	-83	-794	-552	-162	-166
Distribution Sub-Total	50	152	254	224	430	443
Meter Replacements						
Metering & Minor Storm Damage	167	270	91	158	95	278
Removals	-20	-26	-6	-12	-6	-29
Metering & Minor Storm Damage Sub-Total	147	244	85	146	89	249
Capital Trouble (Storm Damage)						
Capital Trouble (Storm Damage)	0	0	0	0	117	121
Removals	0	0	0	0	-14	-15
Metering & Minor Storm Damage Sub-Total	0	0	0	0	103	106
Damage Claims & Small External Demand Requests						
Damage Claims & Small External Demand Requests	24	42	20	54	55	56
Contributions and Removals	-24	-42	-20	-13	-55	-56
Damage Claims & Small External Demand Requests Sub	0	0	0	41	0	0
Return Used Transformers to Inventory						
Return Used Transformers to Inventory	0	0	0	0	0	0
Return Used Transformers to Inventory Sub-Total	0	0	0	0	0	0
SYSTEM RENEWAL Distribution Sub-Total	**197**	**396**	**339**	**411**	**622**	**798**
Generation						
Engine Replacements						
Engine Replacements	0	0	0	0	0	0
Armstrong Replacements	0	0	0	0	0	1,270
Bearskin Replacements	283	10	-294	0	0	0
Big Trout Unit Generator Replacements	3	321	-265	72	0	0
Big Trout Lake (KI) A Unit Generator Replacement	0	0	0	0	4,287	868
Biscotasing Replacements	95	110	237	22	0	0
Deer Lake Replacements	0	0	390	650	1,080	0
Hillsport Replacements	0	0	119	193	0	148
Kasabonika Replacements	0	50	-50	0	0	0
Lansdowne Replacements	0	0	0	0	0	296
Marten Falls Replacements	1,429	0	0	0	0	0
Oba Replacements	93	96	0	0	0	0
Sachigo Replacements	0	0	0	811	0	0
Sultan Replacements	0	0	151	21	0	0
Contributions and Removals	-187	-56	22	-526	-55	-106
Engine Replacements Sub-Total	1,716	531	310	1,243	5,312	2,476
Engine Overhauls						
Armstrong Overhauls	0	0	0	0	0	0
Armstrong Overhauls	0	87	495	0	0	0
Bearskin Overhauls	0	0	0	255	0	0
Big Trout Lake Overhauls	12	0	0	0	0	0
Deer Lake Overhauls	0	0	185	2	0	0
Fort Severn Overhauls	0	0	381	0	0	128
Gull Bay Overhauls	0	0	0	183	0	0
Kasabonika Overhauls	8	0	374	0	0	0
Kingfisher Overhauls	95	0	0	184	0	0
Lansdowne Overhauls	132	0	179	2	0	0
Marten Falls Overhauls	198	8	0	0	0	0
Oba Overhauls	0	0	0	0	0	44
Sachigo Overhauls	0	129	0	539	0	0
Sultan Overhauls	104	0	0	0	0	0
Wapekeka Overhauls	0	149	0	0	0	0
Weagamow Overhauls	0	214	0	0	0	0
Webequie Overhauls	0	620	-4	0	0	0
Removals	-53	-119	-159	-115	0	-18
Engine Overhauls Sub-Total	496	1,088	1,451	1,050	0	154

Emergency System Breakdowns						
Armstrong Emergency Replacement	204	0	0	0	0	0
Lansdowne Emergency Replacement	0	213	0	0	0	0
Big Trout Emergency Rebuild	0	545	0	0	0	0
Sandy Lake Emergency Overhauls	0	0	607	7	0	0
Biscotasing Emergency Replacement	0	0	77	63	0	0
Removals	-20	-75	-67	-6	0	0
Emergency System Breakdowns Sub-Total	184	683	617	64	0	0
Backup Generation						
Backup Station Design	0	0	0	61	0	0
Wunnimun	0	0	0	0	30	200
Poplar Hill	0	0	0	0	0	30
Muskrat Dam	0	0	0	0	30	207
North Spirit	0	0	0	0	0	30
Keewaywin -Design Only	0	0	0	0	0	30
Deer Lake	0	0	0	0	0	30
Kingfisher	0	0	0	0	87	0
Sandy Lake	0	0	0	0	0	30
Bearskin Lake	0	0	0	0	30	87
Big Trout	0	0	0	0	30	87
Kasabonika	0	0	0	0	30	87
Sachigo	0	0	0	0	30	87
Wapekeka	0	0	0	0	30	87
Contributions	0	0	0	-61	-297	-992
Backup Generation Sub-Total	0	0	0	0	0	0
Fuel Tank Replacements and Diesel Civil Improvements						
Diesel Plant Civil Improvements	335	591	275	166	277	195
DGS Integration - Gull Bay Solar Farm	0	488	197	4	0	0
Hillsport Bulk Tank	68	0	0	0	0	0
Fuel System Improvements	235	59	3	741	0	0
Lansdowne Bullk Tank Replacement	0	0	0	0	0	394
Oba Bulk Tank	5	4	4	158	0	196
Removals	0	-244	-111	-99	0	0
Fuel Tank Replacments, Civil Plant Improve Sub-Total	643	898	368	970	277	785
Renewable Energy Technology						
Wind Turbine	0	98	8	23	121	0
Hydel	0	10	7	43	0	337
Removals	0	-98	-8	-23	-121	0
Renewable Energy Technology Sub-Total	0	10	7	43	0	337
SYSTEM RENEWAL Generation Sub-Total	**3,039**	**3,210**	**2,753**	**3,370**	**5,589**	**3,752**
SYSTEM RENEWAL Sub-Total	**3,236**	**3,606**	**3,092**	**3,781**	**6,211**	**4,550**
SYSTEM SERVICE						
Distribution System Upgrades						
Big Trout Lake/Wapekeka Tie Line	5,861	557	0	0	0	0
Contributions	-5,861	-557	0	0	0	0
Distribution System Upgrades Sub-Total	0	0	0	0	0	0
SYSTEM SERVICE Distribution Sub-Total	**0**	**0**	**0**	**0**	**0**	**0**
Generation Customer Upgrades						
Big Trout Lake/Wapekeka Connection & DGS Upgrade	619	4,816	1,568	18	0	0
Kingfisher Lake	157	0	0	0	0	0
Sandy Lake	12	35	2,711	178	0	0
Weagamow	1	2	0	0	0	0
Gull Bay DGS Upgrade	0	288	672	614	1,002	1,532
Lansdowne	0	0	0	0	0	501
Marten Falls	0	11	2,347	3,200	50	0
Sachigo Lake Hybrid	0	0	0	0	0	0
Webequie	0	0	0	225	3,551	56
Contributions and Removals	-789	-5,152	-7,298	-4,235	-4,603	-2,089
Generator Upgrades Sub-Total	0	0	0	0	0	0
Controls/SCADA Upgrades						
SCADA & PLC Replacements & High Speed Internet	364	148	277	258	117	295
Controls/SCADA Upgrades Sub-Total	364	148	277	258	117	295
SYSTEM SERVICE Generation Sub-Total	**364**	**148**	**277**	**258**	**117**	**295**
SYSTEM SERVICE Sub-Total	**364**	**148**	**277**	**258**	**117**	**295**
General Plant						
General Plant						
Office Expansion/Relocation	0	0	0	0	490	1,476
Staff houses	0	20	11	834	218	0
Garages	44	0	0	306	160	200
Other	0	0	0	0	0	244
Minor Fixed Assets	139	116	136	38	130	130
General Plant Sub-Total	183	136	147	1,178	998	2,050
GENERAL PLANT Sub-Total	**183**	**136**	**147**	**1,178**	**998**	**2,050**
Miscellaneous						
Total	**3,893**	**3,986**	**3,750**	**5,623**	**8,789**	**10,591**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*						
Total	**3,893**	**3,986**	**3,750**	**5,623**	**8,789**	**10,591**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:

2023

CATEGORY		Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
		2018			2019			2020			2021			2022			2023	2024	2025	2026	2027
		Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
		$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access																					
	Gross Capital Spend	897	1,015	13.2%	1,065	1,548	45.4%	1,121	1,195	6.6%	1,143	2,059	80.1%	1,166	2,762	136.9%	5,168	3,980	1,812	1,844	1,877
	Capital Contributions	(897)	(905)	0.9%	(1,065)	(1,452)	36.3%	(1,121)	(961)	-14.3%	(1,143)	(1,653)	44.6%	(1,166)	(1,299)	11.4%	(1,472)	(1,687)	(1,787)	(1,818)	(1,851)
	Net Capital Expenditures	-	110	--	-	96	--	-	234	--	-	406	--	-	1,463	--	3,696	2,293	25	26	26
System Renewal - Distribution																					
	Gross Capital Spend	711	457	-35.7%	899	547	-39.2%	947	1,158	22.3%	965	989	2.5%	983	860	-12.5%	1,063	1,142	944	966	969
	Capital Contributions	(243)	(260)	7.0%	(290)	(151)	-47.9%	(304)	(819)	169.4%	(311)	(578)	85.9%	(313)	(238)	-24.0%	(265)	(283)	(267)	(272)	(277)
	Net Capital Expenditures	468	197	-57.9%	609	396	-35.0%	643	339	-47.3%	654	411	-37.2%	670	622	-7.2%	798	859	677	694	692
System Renewal - Generation																					
	Gross Capital Spend	1,609	3,298	105.0%	2,847	3,804	33.6%	3,582	3,077	-14.1%	3,994	4,200	5.2%	2,921	6,062	107.5%	4,868	4,726	1,787	2,060	1,273
	Capital Contributions	(130)	(260)	100.0%	(211)	(592)	180.6%	(213)	(324)	52.1%	(204)	(830)	306.9%	(205)	(473)	130.7%	(1,116)	(1,138)	(19)	(25)	(34)
	Net Capital Expenditures	1,479	3,038	105.4%	2,636	3,212	21.9%	3,369	2,753	-18.3%	3,790	3,370	-11.1%	2,716	5,589	105.8%	3,752	3,588	1,768	2,035	1,239
System Service - Distribution																					
	Gross Capital Spend	-	5,861	--	-	557	--	-	-	--	-	-	--	-	-	--	-	-	-	-	-
	Capital Contributions	-	(5,861)	--	-	(557)	--	-	-	--	-	-	--	-	-	--	-	-	-	-	-
	Net Capital Expenditures	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--	-	-	-	-	-
System Service - Generation																					
	Gross Capital Spend	5,777	1,153	-80.0%	6,852	5,300	-22.7%	6,392	7,575	18.5%	5,412	4,493	-17.0%	5,315	4,720	-11.2%	2,384	2,456	312	218	186
	Capital Contributions	(5,323)	(789)	-85.2%	(6,126)	(5,152)	-15.9%	(5,717)	(7,298)	27.7%	(5,021)	(4,235)	-15.7%	(4,962)	(4,603)	-7.2%	(2,089)	(2,105)	-	-	-
	Net Capital Expenditures	454	364	-19.8%	726	148	-79.6%	675	277	-59.0%	391	258	-34.0%	353	117	-66.9%	295	351	312	218	186
General Plant																					
	Gross Capital Spend	509	183	-64.0%	572	136	-76.2%	581	147	-74.7%	590	1,178	99.7%	598	998	66.9%	2,050	556	552	560	560
	Capital Contributions	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--	-	-	-	-	-
	Net Capital Expenditures	509	183	-64.0%	572	136	-76.2%	581	147	-74.7%	590	1,178	99.7%	598	998	66.9%	2,050	556	552	560	560
TOTAL EXPENDITURE		9,503	11,967	25.9%	12,235	11,892	-2.8%	12,623	13,152	4.2%	12,104	12,919	6.7%	10,983	15,402	40.2%	15,533	12,860	5,407	5,648	4,865
Capital Contributions		(6,593)	(8,075)	22.5%	(7,692)	(7,904)	2.8%	(7,355)	(9,402)	27.8%	(6,679)	(7,296)	9.2%	(6,646)	(6,613)	-0.5%	(4,942)	(5,213)	(2,073)	(2,115)	(2,162)
Net Capital Expenditures		2,910	3,892	33.7%	4,543	3,988	-12.2%	5,268	3,750	-28.8%	5,425	5,623	3.6%	4,337	8,789	102.7%	10,591	7,647	3,334	3,533	2,703
System O&M		21,343	19,608	-8.1%	23,888	21,088	-11.7%	25,291	21,186	-16.2%	25,790	20,606	-20.1%	26,053	22,534	-13.5%	22,041	22,246	23,314	23,443	22,925
Fuel		25,900	29,406	13.5%	28,874	30,251	4.8%	31,872	29,166	-8.5%	33,438	34,481	3.1%	34,110	41,200	20.8%	30,365	16,421	13,818	13,983	14,141
Other Power Supply Expenses		-	14	--	81	1,463	1706.2%	85	1,779	1992.9%	87	1,584	1720.7%	90	2,795	3005.6%	8,162	14,106	15,954	16,351	16,898
Watay Tx Connection Costs		-	-	--	-	-	--	-	-	--	-	-	--	-	21,285	--	66,000	103,695	103,695	103,695	103,695
Total O&M		$ 47,243	$ 49,028	3.8%	$ 52,843	$ 52,802	-0.1%	$ 57,248	$ 52,131	-8.9%	$ 59,315	$ 56,671	-4.5%	$ 60,253	$ 87,814	45.7%	$ 126,568	$ 156,468	$ 156,781	$ 157,472	$ 157,659

Project Specific Capital Contributions

CATEGORY	Capital Contributions	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
		2018			2019			2020			2021			2022			2022	2023	2024	2025	2026
			Actual			Actual			Actual			Actual			Actual[2]						
			$ '000			$ '000			$ '000			$ '000			$ '000				$ '000		
System Access																					
	New Customer Connections & Service Upgrades		(757)			(1,239)			(780)			(1,306)			(997)		(1,113)	(1,255)	(1,322)	(1,346)	(1,371)
	All Other Capital Contributions		(148)			(213)			(181)			(347)			(302)		(359)	(432)	(465)	(472)	(480)
	Total Capital Contributions		(905)			(1,452)			(961)			(1,653)			(1,299)		(1,472)	(1,687)	(1,787)	(1,818)	(1,851)
System Renewal - Distribution																					
	Normal Distribution Sustainment & Renewal		(89)			(83)			(174)			(89)			(162)		(166)	(178)	(185)	(189)	(193)
	Large Project Customer Distribution Sustainment & Renewal		(128)						(620)			(463)									
	All Other Capital Contributions		(43)			(68)			(25)			(26)			(76)		(99)	(105)	(82)	(83)	(84)
	Total Capital Contributions		(260)			(151)			(819)			(578)			(238)		(265)	(283)	(267)	(272)	(277)
System Renewal - Generation																					
	Engine Replacements & Overhauls		(240)			(176)			(137)			(90)			(55)		(124)	(271)	(19)	(25)	(34)
	Sachigo Temporary Generation Unit		-			-			-			(550)			-		-	-	-	-	-
	Backup Power (Various Watay Communities)		-			-			-			(61)			(297)		(992)	(843)	-	-	-
	Generation Development		-			(244)			(95)			(86)			-		-	-	-	-	-
	All Other Capital Contributions		(20)			(172)			(92)			(43)			(121)		-	(24)	-	-	-
	Total Capital Contributions		(260)			(592)			(324)			(830)			(473)		(1,116)	(1,138)	(19)	(25)	(34)
System Service - Distribution																					
	Big Trout Lake/Wapekeka Tie Line		(5,861)			(557)			-			-			-		-	-	-	-	-
	All Other Capital Contributions		-			-			-			-			-		-	-	-	-	-
	Total Capital Contributions		(5,861)			(557)			-			-			-		-	-	-	-	-
System Service - Generation																					
	Wapekeka Upgrade (Big Trout/Wapekeka Connection)		(619)			(4,817)			(1,569)			(19)			-		-	-	-	-	-
	Sandy Lake Upgrade		(12)			(36)			(2,710)			(177)			-		-	-	-	-	-
	Marten Falls Upgrade		-			(11)			(2,347)			(3,200)			(50)		-	-	-	-	-
	Gull Bay Upgrade		-			(288)			(672)			(614)			(1,002)		(1,532)	-	-	-	-
	Webequie Upgrade		-			-			-			(225)			(3,551)		(56)	-	-	-	-
	All Other Capital Contributions		(158)			-			-			-			-		(501)	(2,105)	-	-	-
	Total Capital Contributions		(789)			(5,152)			(7,298)			(4,235)			(4,603)		(2,089)	(2,105)	-	-	-
TOTAL CAPITAL CONTRIBUTIONS			(8,075)			(7,904)			(9,402)			(7,296)			(6,613)		(4,942)	(5,213)	(2,073)	(2,115)	(2,162)

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed. However, use the last OEB-approved, at least on a Total (Capital) Expenditure basis for the last cost of service rebasing year, and the applicant should include their planned budget in each subsequent historical year up to and including the Bridge Year.

2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

3. System O&M contains the following accounts: 5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5060, 5065, 5070, 5075, 5085, 5090, 5095, 5096, 5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5165, 5170, 5172, 5175, 5178, 5195

Explanatory Notes on Variances (complete only if applicable)
Notes on shifts in forecast vs. historical budgets by category
Notes on year over year Plan vs. Actual variances for Total Expenditures
Notes on Plan vs. Actual variance trends for individual expenditure categories

Appendix 2-BA

Fixed Asset Continuity Schedule [1]

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts. If this is the first application where the applicant is rebasing under MIFRS, contact OEB staff for further guidance on the appropriate fixed asset continuity schedules to complete (i.e. applicable years and accounting standard for each schedule).

2. The "CCA Class" for fixed assets should generally agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the OEB.

4. The additions in column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues. Amortization of deferred revenue will be removed from the depreciation expense shown on this fixed asset continuity schedule as it should be included as income in Appendix 2-H Other Revenues.

6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

7. This account includes the amount recorded under finance leases for plant leased from others and used by the utility in its utility operations.

8. The applicant must establish the continuity of historical cost for gross assets and accumulated depreciation by asset class by ensuring that the opening balance in the year agrees to the closing balance in the prior year.

Accounting Standard USGAAP
Year 2018

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1615	Land	$ 407,800	$ -	$ -	$ 407,800	-$ 407,800	$ -	$ -	-$ 407,800	$ -
1	1620	Buildings &Fixtures	$ 5,737,693	$ 275,077	-$ 70,618	$ 5,942,152	-$ 2,105,350	-$ 155,672	$ 70,618	-$ 2,190,404	$ 3,751,748
17	1650	Reservoirs Dams & Water	$ 670,778	$ -	$ -	$ 670,778	-$ 670,778	$ -	$ -	-$ 670,778	$ -
17	1665	Fuel Holders Produce	$ 7,352,566	$ 473,969	$ -	$ 7,826,535	-$ 1,054,557	-$ 223,350	$ -	-$ 1,277,907	$ 6,548,628
17	1670	Prime Movers	$ 16,705,999	$ 1,580,646	-$ 1,895,619	$ 16,391,026	-$ 11,389,757	-$ 1,175,596	$ 1,895,619	-$ 10,669,734	$ 5,721,292
17	1675	Generators	$ 8,814,700	$ 459,107	-$ 705,380	$ 8,568,427	-$ 3,954,517	-$ 474,993	$ 705,380	-$ 3,724,130	$ 4,844,297
17	1680	Accessory Electc Equ	$ 1,793,348	$ -	-$ 9,204	$ 1,784,144	-$ 398,273	-$ 97,183	$ 9,204	-$ 486,252	$ 1,297,892
17	1685	Misc Power Plant Equ	$ 4,203,502	$ 458,033	$ -	$ 4,661,535	-$ 2,364,736	-$ 133,304	$ -	-$ 2,498,040	$ 2,163,495
N/A	1805	Land	$ 294,456	$ -	$ -	$ 294,456	-$ 118,469	-$ 1,428	$ -	-$ 119,897	$ 174,559
CEC	1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	-$ 71,990	-$ 2,271	$ -	-$ 74,261	$ 159,865
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,406,457	$ 170,037	-$ 18,544	$ 3,557,950	-$ 572,107	-$ 61,733	$ 18,544	-$ 615,296	$ 2,942,654
47	1835	Overhead Conductors & Devices	$ 2,429,347	$ 29,973	-$ 21,241	$ 2,438,079	-$ 500,100	-$ 46,892	$ 21,241	-$ 525,751	$ 1,912,328
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 292,362	$ -	-$ 108	$ 292,254	-$ 152,453	-$ 7,699	$ 108	-$ 160,044	$ 132,210
47	1850	Line Transformers	$ 2,360,780	$ 67,867	-$ 310,368	$ 2,118,279	-$ 719,280	-$ 57,273	$ 205,167	-$ 571,386	$ 1,546,893
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters				$ -				$ -	$ -
47	1860	Meters (Smart Meters)	$ 642,553	$ 219,071	-$ 39,333	$ 822,291	-$ 199,461	-$ 49,264	$ 39,333	-$ 209,392	$ 612,899
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 11,327,706	$ 582,300	$ -	$ 11,910,006	-$ 2,284,200	-$ 228,244	$ -	-$ 2,512,444	$ 9,397,562
13	1910	Leasehold Improvements	$ 115,183	$ -	$ -	$ 115,183	-$ 67,334	-$ 12,993	$ -	-$ 80,327	$ 34,856
8	1915	Office Furniture & Equipment (10 years)				$ -		$ -		$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 51,469	$ -	$ -	$ 51,469	-$ 34,240	-$ 7,353	$ -	-$ 41,593	$ 9,876
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 27,715	$ -	-$ 27,715	$ -	-$ 27,715	$ -	$ 27,715	$ -	$ -
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ 140,160	$ -	$ -	$ 140,160	-$ 110,513	-$ 16,838	$ -	-$ 127,351	$ 12,809
8	1940	Tools, Shop & Garage Equipment	$ 132,086	$ 17,617	-$ 28,319	$ 121,384	-$ 76,031	-$ 18,615	$ 28,319	-$ 66,327	$ 55,057
8	1945	Measurement & Testing Equipment	$ 99,327	$ 7,810	-$ 57,030	$ 50,107	-$ 71,428	-$ 14,943	$ 57,030	-$ 29,341	$ 20,766
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 20,332	$ -	$ -	$ 20,332	-$ 29,495	-$ 687	$ -	-$ 30,182	-$ 9,850
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 706,614	$ 113,494	-$ 133,855	$ 686,253	-$ 372,586	-$ 138,972	$ 133,855	-$ 377,703	$ 308,550
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property				$ -	-$ 240,316	$ -	$ -	-$ 240,316	-$ 240,316
47	1995	Contributions & Grants				$ -	$ 172,061	$ -	$ -	$ 172,061	$ 172,061
47	2440	Deferred Revenue[5]				$ -	$ -	$ -	$ -	$ -	$ -
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 67,967,059**	**$ 4,455,001**	**-$ 3,317,334**	**$ 69,104,726**	**-$ 27,821,425**	**-$ 2,925,303**	**$ 3,212,133**	**-$ 27,534,595**	**$ 41,570,131**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 67,967,059**	**$ 4,455,001**	**-$ 3,317,334**	**$ 69,104,726**	**-$ 27,821,425**	**-$ 2,925,303**	**$ 3,212,133**	**-$ 27,534,595**	**$ 41,570,131**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,925,303**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 2,925,303**

Accounting Standard USGAAP
Year **2019**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ 407,800	$ -	$ -	$ 407,800	-$ 407,800	$ -	$ -	-$ 407,800	$ -
1	1620	Buildings &Fixtures	$ 5,942,152	$ 282,724	$ 348,573	$ 6,573,449	-$ 2,190,404	-$ 171,425	$ -	-$ 2,361,829	$ 4,211,620
17	1650	Reservoirs Dams & Water	$ 670,778	$ -	$ -	$ 670,778	-$ 670,778	$ -	$ -	-$ 670,778	$ -
17	1665	Fuel Holders Produce	$ 7,826,535	$ -	$ -	$ 7,826,535	-$ 1,277,907	-$ 216,795	$ -	-$ 1,494,702	$ 6,331,833
17	1670	Prime Movers	$ 16,391,026	$ 1,674,310	-$ 2,069,340	$ 15,995,996	-$ 10,669,734	-$ 1,131,626	$ 2,069,340	-$ 9,732,020	$ 6,263,976
17	1675	Generators	$ 8,568,427	$ 467,692	-$ 472,775	$ 8,563,344	-$ 3,724,130	-$ 454,721	$ 472,775	-$ 3,706,076	$ 4,857,268
17	1680	Accessory Electc Equ	$ 1,784,144	$ -	$ -	$ 1,784,144	-$ 486,252	-$ 97,057	$ -	-$ 583,309	$ 1,200,835
17	1685	Misc Power Plant Equ	$ 4,661,535	$ -	-$ 178,549	$ 4,482,986	-$ 2,498,040	-$ 126,313	$ 178,549	-$ 2,445,804	$ 2,037,182
N/A	1805	Land	$ 294,456	$ -	$ -	$ 294,456	-$ 119,897	$ -	$ -	-$ 119,897	$ 174,559
CEC	1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	-$ 74,261	-$ 2,271	$ -	-$ 76,532	$ 157,594
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,557,950	$ 99,255	-$ 31,066	$ 3,626,139	-$ 615,296	-$ 64,291	$ 31,066	-$ 648,521	$ 2,977,618
47	1835	Overhead Conductors & Devices	$ 2,438,079	$ 42,040	-$ 1,718	$ 2,478,401	-$ 525,751	-$ 47,830	$ 1,718	-$ 571,863	$ 1,906,538
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 292,254	$ -	$ -	$ 292,254	-$ 160,044	-$ 7,698	$ -	-$ 167,742	$ 124,512
47	1850	Line Transformers	$ 2,118,279	$ 330,852	-$ 2,801	$ 2,446,330	-$ 571,386	-$ 58,511	-$ 189,686	-$ 819,583	$ 1,626,747
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 822,291	$ 349,068	-$ 28,983	$ 1,142,376	-$ 209,392	-$ 69,435	$ 28,983	-$ 249,844	$ 892,532
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 11,910,006	$ -	-$ 348,573	$ 11,561,433	-$ 2,512,444	-$ 227,173	$ -	-$ 2,739,617	$ 8,821,816
13	1910	Leasehold Improvements	$ 115,183	$ -	$ -	$ 115,183	-$ 80,327	-$ 12,993	$ -	-$ 93,320	$ 21,863
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 51,469	$ -	-$ 29,769	$ 21,700	-$ 41,593	-$ 5,226	$ 29,769	-$ 17,050	$ 4,650
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ 140,160	$ -	-$ 96,940	$ 43,220	-$ 127,351	-$ 10,107	$ 96,940	-$ 40,518	$ 2,702
8	1940	Tools, Shop & Garage Equipment	$ 121,384	$ -	-$ 14,530	$ 106,854	-$ 66,327	-$ 17,605	$ 14,530	-$ 69,402	$ 37,452
8	1945	Measurement & Testing Equipment	$ 50,107	$ 50,244	-$ 19,962	$ 80,389	-$ 29,341	-$ 13,050	$ 19,962	-$ 22,429	$ 57,960
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 20,332	$ -	$ -	$ 20,332	-$ 30,182	-$ 687	$ -	-$ 30,869	-$ 10,537
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 686,253	$ 64,775	-$ 97,257	$ 653,771	-$ 377,703	-$ 131,954	$ 97,257	-$ 412,400	$ 241,371
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	-$ 240,316	$ -	$ -	-$ 240,316	-$ 240,316
47	1995	Contributions & Grants	$ -			$ -	$ 172,061	$ -	$ -	$ 172,061	$ 172,061
47	2440	Deferred Revenue[5]	$ -			$ -	$ -	$ -	$ -	$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 69,104,726**	**$ 3,360,960**	**-$ 3,043,690**	**$ 69,421,996**	**-$ 27,534,595**	**-$ 2,866,768**	**$ 2,851,203**	**-$ 27,550,160**	**$ 41,871,836**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -			$ -	$ -			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 69,104,726**	**$ 3,360,960**	**-$ 3,043,690**	**$ 69,421,996**	**-$ 27,534,595**	**-$ 2,866,768**	**$ 2,851,203**	**-$ 27,550,160**	**$ 41,871,836**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,866,768**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 2,866,768**

Accounting Standard	USGAAP
Year	**2020**

			Cost				**Accumulated Depreciation**				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ 407,800	$ -	$ -	$ 407,800	-$ 407,800	$ -	$ -	-$ 407,800	$ -
1	1620	Buildings &Fixtures	$ 6,573,449	$ 655,230	-$ 313,608	$ 6,915,071	-$ 2,361,829	-$ 174,968	$ -	-$ 2,536,797	$ 4,378,274
17	1650	Reservoirs Dams & Water	$ 670,778	$ -	$ -	$ 670,778	-$ 670,778	$ -	$ -	-$ 670,778	$ -
17	1665	Fuel Holders Produce	$ 7,826,535	$ -	$ -	$ 7,826,535	-$ 1,494,702	-$ 216,795	$ -	-$ 1,711,497	$ 6,115,038
17	1670	Prime Movers	$ 15,995,996	$ 900,823	$ -	$ 16,896,819	-$ 9,732,020	-$ 1,103,661	$ -	-$ 10,835,681	$ 6,061,138
17	1675	Generators	$ 8,563,344	$ 300,274	$ -	$ 8,863,618	-$ 3,706,076	-$ 455,111	$ -	-$ 4,161,187	$ 4,702,431
17	1680	Accessory Electc Equ	$ 1,784,144	$ -	$ -	$ 1,784,144	-$ 583,309	-$ 97,057	$ -	-$ 680,366	$ 1,103,778
17	1685	Misc Power Plant Equ	$ 4,482,986	$ 506,538	$ -	$ 4,989,524	-$ 2,445,804	-$ 129,799	$ -	-$ 2,575,603	$ 2,413,921
N/A	1805	Land	$ 294,456	$ -	$ -	$ 294,456	-$ 119,897	$ -	$ -	-$ 119,897	$ 174,559
CEC	1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	-$ 76,532	-$ 2,271	$ -	-$ 78,803	$ 155,323
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,626,139	$ -	-$ 1,075	$ 3,625,064	-$ 648,521	-$ 64,535	$ 1,075	-$ 711,981	$ 2,913,083
47	1835	Overhead Conductors & Devices	$ 2,478,401	$ 2,961	-$ 5,413	$ 2,475,949	-$ 571,863	-$ 51,974	$ 5,413	-$ 618,424	$ 1,857,525
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 292,254	$ -	$ -	$ 292,254	-$ 167,742	-$ 7,698	$ -	-$ 175,440	$ 116,814
47	1850	Line Transformers	$ 2,446,330	$ -	-$ 6,233	$ 2,440,097	-$ 819,583	-$ 60,243	$ 6,233	-$ 873,593	$ 1,566,504
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ -			$ -	$ -			$ -	$ -
47	1860	Meters (Smart Meters)	$ 1,142,376	$ 55,032	$ -	$ 1,197,408	-$ 249,844	-$ 80,091	$ -	-$ 329,935	$ 867,473
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 11,561,433	$ -	$ 313,608	$ 11,875,041	-$ 2,739,617	-$ 229,165	$ -	-$ 2,968,782	$ 8,906,259
13	1910	Leasehold Improvements	$ 115,183	$ -	$ -	$ 115,183	-$ 93,320	-$ 12,993	$ -	-$ 106,313	$ 8,870
8	1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 21,700	$ -	$ -	$ 21,700	-$ 17,050	-$ 3,100	$ -	-$ 20,150	$ 1,550
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ 22,377	$ -	$ 22,377	$ -	-$ 2,238	$ -	-$ 2,238	$ 20,139
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ 43,220	$ -	-$ 43,220	$ -	-$ 40,518	-$ 2,702	$ 43,220	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 106,854	$ 34,696	-$ 38,622	$ 102,928	-$ 69,402	-$ 16,495	$ 38,622	-$ 47,275	$ 55,653
8	1945	Measurement & Testing Equipment	$ 80,389	$ -	-$ 4,380	$ 76,009	-$ 22,429	-$ 15,104	$ 4,380	-$ 33,153	$ 42,856
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 20,332	$ -	$ -	$ 20,332	-$ 30,869	-$ 687	$ -	-$ 31,556	-$ 11,224
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 653,771	$ 79,205	-$ 279,707	$ 453,269	-$ 412,400	-$ 106,901	$ 279,707	-$ 239,594	$ 213,675
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	-$ 240,316	$ -	$ -	-$ 240,316	-$ 240,316
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ 172,061	$ -	$ -	$ 172,061	$ 172,061
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 69,421,996**	**$ 2,557,136**	**-$ 378,650**	**$ 71,600,482**	**-$ 27,550,160**	**-$ 2,833,588**	**$ 378,650**	**-$ 30,005,098**	**$ 41,595,384**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 69,421,996**	**$ 2,557,136**	**-$ 378,650**	**$ 71,600,482**	**-$ 27,550,160**	**-$ 2,833,588**	**$ 378,650**	**-$ 30,005,098**	**$ 41,595,384**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,833,588**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 2,833,588**

Accounting Standard: USGAAP
Year: 2021

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ 407,800	$ -	$ -	$ 407,800	-$ 407,800	$ -	$ -	-$ 407,800	$ -
1	1620	Buildings &Fixtures	$ 6,915,071	$ 157,605	-$ 68,678	$ 7,003,998	-$ 2,536,797	-$ 176,525	$ 68,678	-$ 2,644,644	$ 4,359,354
17	1650	Reservoirs Dams & Water	$ 670,778	$ -	$ -	$ 670,778	-$ 670,778	$ -	$ -	-$ 670,778	$ -
17	1665	Fuel Holders Produce	$ 7,826,535	$ 762,065	-$ 118,091	$ 8,470,509	-$ 1,711,497	-$ 227,068	$ 118,091	-$ 1,820,474	$ 6,650,035
17	1670	Prime Movers	$ 16,896,819	$ 1,857,809	-$ 834,106	$ 17,920,522	-$ 10,835,681	-$ 1,242,046	$ 834,106	-$ 11,243,621	$ 6,676,901
17	1675	Generators	$ 8,863,618	$ 772,470	-$ 276,196	$ 9,359,892	-$ 4,161,187	-$ 492,267	$ 276,196	-$ 4,377,258	$ 4,982,634
17	1680	Accessory Electc Equ	$ 1,784,144	$ -	-$ 29,158	$ 1,754,986	-$ 680,366	-$ 96,793	$ 29,158	-$ 748,001	$ 1,006,985
17	1685	Misc Power Plant Equ	$ 4,989,524	$ 940,629	$ -	$ 5,930,153	-$ 2,575,603	-$ 177,198	$ -	-$ 2,752,801	$ 3,177,352
N/A	1805	Land	$ 294,456	$ -	$ -	$ 294,456	-$ 119,897	$ -	$ -	-$ 119,897	$ 174,559
CEC	1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	-$ 78,803	-$ 2,271	$ -	-$ 81,074	$ 153,052
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,625,064	$ 516,823	-$ 21,310	$ 4,120,577	-$ 711,981	-$ 70,900	$ 21,310	-$ 761,571	$ 3,359,006
47	1835	Overhead Conductors & Devices	$ 2,475,949	$ 58,784	-$ 990	$ 2,533,743	-$ 618,424	-$ 48,633	$ 990	-$ 666,067	$ 1,867,676
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 292,254	$ -	$ -	$ 292,254	-$ 175,440	-$ 7,698	$ -	-$ 183,138	$ 109,116
47	1850	Line Transformers	$ 2,440,097	$ 105,928	-$ 1,191	$ 2,544,834	-$ 873,593	-$ 60,873	$ 1,191	-$ 933,275	$ 1,611,559
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 1,197,408	$ 117,691	-$ 32,829	$ 1,282,270	-$ 329,935	-$ 81,482	$ 32,829	-$ 378,588	$ 903,682
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 11,875,041	$ 492,183	$ -	$ 12,367,224	-$ 2,968,782	-$ 238,492	$ -	-$ 3,207,274	$ 9,159,950
13	1910	Leasehold Improvements	$ 115,183	$ -	$ -	$ 115,183	-$ 106,313	-$ 12,993	$ -	-$ 119,306	-$ 4,123
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ 21,700	$ -	-$ 21,700	$ -	-$ 20,150	-$ 1,550	$ 21,700	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 22,377	$ 4,960	$ -	$ 27,337	-$ 2,238	-$ 4,830	$ -	-$ 7,068	$ 20,269
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 102,928	$ 5,148	-$ 4,329	$ 103,747	-$ 47,275	-$ 17,223	$ 4,329	-$ 60,169	$ 43,578
8	1945	Measurement & Testing Equipment	$ 76,009	$ -	-$ 5,355	$ 70,654	-$ 33,153	-$ 14,131	$ 5,355	-$ 41,929	$ 28,725
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 20,332	$ -	$ -	$ 20,332	-$ 31,556	-$ 687	$ -	-$ 32,243	-$ 11,911
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 453,269	$ 28,419	-$ 80,188	$ 401,500	-$ 239,594	-$ 84,832	$ 80,188	-$ 244,238	$ 157,262
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	-$ 240,316	$ -	$ -	-$ 240,316	-$ 240,316
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ 172,061	$ -	$ -	$ 172,061	$ 172,061
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 71,600,482**	**$ 5,820,514**	**-$ 1,494,121**	**$ 75,926,875**	**-$ 30,005,098**	**-$ 3,058,492**	**$ 1,494,121**	**-$ 31,569,469**	**$ 44,357,406**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 71,600,482**	**$ 5,820,514**	**-$ 1,494,121**	**$ 75,926,875**	**-$ 30,005,098**	**-$ 3,058,492**	**$ 1,494,121**	**-$ 31,569,469**	**$ 44,357,406**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,058,492**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 3,058,492**

Accounting Standard USGAAP
Year 2022

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Reserve Reallocation*	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -			$ -	$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -				$ -	$ -
N/A	1615	Land	$ 407,800	$ -	$ -	$ 407,800	-$ 407,800	$ -	$ -	$ -	-$ 407,800	$ -
1	1620	Buildings &Fixtures	$ 7,003,998	$ 13,997	$ -	$ 7,017,995	-$ 2,644,644	-$ 159,535	$ -	-$ 735,107	-$ 3,539,286	$ 3,478,709
17	1650	Reservoirs Dams & Water	$ 670,778	$ -	$ -	$ 670,778	-$ 670,778	$ -	$ -	$ -	-$ 670,778	$ -
17	1665	Fuel Holders Produce	$ 8,470,509	$ 83,984	$ -	$ 8,554,493	-$ 1,820,474	-$ 194,536	$ -	-$ 2,179,273	-$ 4,194,283	$ 4,360,210
17	1670	Prime Movers	$ 17,920,522	$ 1,868,651	-$ 747,460	$ 19,041,713	-$ 11,243,621	-$ 1,265,364	$ 747,460	$ 3,797,541	-$ 7,963,984	$ 11,077,729
17	1675	Generators	$ 9,359,892	$ 664,875	-$ 265,950	$ 9,758,817	-$ 4,377,258	-$ 503,824	$ 265,950	-$ 639,126	-$ 5,254,258	$ 4,504,559
17	1680	Accessory Electc Equ	$ 1,754,986	$ 269,606	$ -	$ 2,024,592	-$ 748,001	-$ 102,804	$ -	-$ 442,417	-$ 1,293,222	$ 731,370
17	1685	Misc Power Plant Equ	$ 5,930,153	$ 69,987	$ -	$ 6,000,140	-$ 2,752,801	-$ 172,581	$ -	$ 130,127	-$ 2,795,255	$ 3,204,885
N/A	1805	Land	$ 294,456	$ -	$ -	$ 294,456	-$ 119,897	$ -	$ -	$ 119,897	-$ 0	$ 294,456
CEC	1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	-$ 81,074	-$ 2,271	$ -	-$ 123,056	-$ 206,401	$ 27,725
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,120,577	$ 322,457	-$ 32,246	$ 4,410,788	-$ 761,571	-$ 75,948	$ 32,246	-$ 147,486	-$ 952,759	$ 3,458,029
47	1835	Overhead Conductors & Devices	$ 2,533,743	$ 251,622	-$ 40,259	$ 2,745,106	-$ 666,067	-$ 51,671	$ 40,259	$ 115,096	-$ 562,383	$ 2,182,723
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 292,254	$ -	$ -	$ 292,254	-$ 183,138	-$ 7,698	$ -	$ 37,688	-$ 153,148	$ 139,106
47	1850	Line Transformers	$ 2,544,834	$ 170,692	-$ 34,138	$ 2,681,388	-$ 933,275	-$ 63,297	$ 34,138	$ 46,351	-$ 916,083	$ 1,765,305
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 1,282,270	$ 867,581	-$ 173,516	$ 1,976,335	-$ 378,588	-$ 94,453	$ 173,516	-$ 48,491	-$ 348,016	$ 1,628,319
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 12,367,224	$ 1,057,338	$ -	$ 13,424,562	-$ 3,207,274	-$ 267,655	$ -	-$ 28,981	-$ 3,503,910	$ 9,920,652
13	1910	Leasehold Improvements	$ 115,183	$ -	$ -	$ 115,183	-$ 119,306	-$ 12,993	$ -	$ 15,901	-$ 116,398	-$ 1,215
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 27,337	$ -	$ -	$ 27,337	-$ 7,068	-$ 5,603	$ -	-$ 142	-$ 12,813	$ 14,524
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 103,747	$ 19,500	-$ 36,445	$ 86,802	-$ 60,169	-$ 13,306	$ 36,445	$ 0	-$ 37,030	$ 49,772
8	1945	Measurement & Testing Equipment	$ 70,654	$ 19,500	-$ 12,600	$ 77,554	-$ 41,929	-$ 13,981	$ 12,600	$ -	-$ 43,310	$ 34,244
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 20,332	$ -	$ -	$ 20,332	-$ 32,243	-$ 687	$ -	$ 11,911	-$ 21,019	-$ 687
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 401,500	$ 91,000	-$ 117,832	$ 374,668	-$ 244,238	-$ 67,117	$ 117,832	$ 1,310	-$ 192,213	$ 182,455
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	-$ 240,316	$ -	$ -	$ 240,316	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ 172,061	$ -	$ -	-$ 172,061	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -				$ -	$ -
		Sub-Total	**$ 75,926,875**	**$ 5,770,790**	**-$ 1,460,446**	**$ 80,237,219**	**-$ 31,569,469**	**-$ 3,075,324**	**$ 1,460,446**	**-$ 0**	**-$ 33,184,347**	**$ 47,052,872**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -					$ -	$ -
		Total PP&E	**$ 75,926,875**	**$ 5,770,790**	**-$ 1,460,446**	**$ 80,237,219**	**-$ 31,569,469**	**-$ 3,075,324**	**$ 1,460,446**	**-$ 0**	**-$ 33,184,347**	**$ 47,052,872**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
		Total						**-$ 3,075,324**				

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 3,075,324**

* see Exhibit B-03-01-02

Accounting Standard USGAAP
Year 2023

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ 407,800	$ -	$ -	$ 407,800	-$ 407,800	$ -	$ -	-$ 407,800	$ -
1	1620	Buildings &Fixtures	$ 7,017,995	$ -	$ -	$ 7,017,995	-$ 3,539,286	-$ 170,538	$ -	-$ 3,709,824	$ 3,308,171
17	1650	Reservoirs Dams & Water	$ 670,778	$ -	$ -	$ 670,778	-$ 670,778	$ -	$ -	-$ 670,778	$ -
17	1665	Fuel Holders Produce	$ 8,554,493	$ 839,190	$ -	$ 9,393,683	-$ 4,194,283	-$ 344,830	$ -	-$ 4,539,113	$ 4,854,570
17	1670	Prime Movers	$ 19,041,713	$ 4,169,735	$ 1,667,894	$ 24,879,342	-$ 7,963,984	-$ 1,301,085	-$ 1,667,894	-$ 10,932,963	$ 13,946,379
17	1675	Generators	$ 9,758,817	$ 1,628,582	$ 651,433	$ 12,038,832	-$ 5,254,258	-$ 463,076	-$ 651,433	-$ 6,368,767	$ 5,670,065
17	1680	Accessory Electc Equ	$ 2,024,592	$ 294,713	$ -	$ 2,319,305	-$ 1,293,222	-$ 78,879	$ -	-$ 1,372,101	$ 947,204
17	1685	Misc Power Plant Equ	$ 6,000,140	$ 355,589	$ -	$ 6,355,729	-$ 2,795,255	-$ 139,665	$ -	-$ 2,934,920	$ 3,420,809
N/A	1805	Land	$ 294,456	$ -	$ -	$ 294,456	-$ 0	$ -	$ -	-$ 0	$ 294,456
CEC	1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	-$ 206,401	-$ 3,442	$ -	-$ 209,843	$ 24,283
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,410,788	$ 426,005	$ 42,601	$ 4,879,394	-$ 952,759	-$ 79,341	-$ 42,601	-$ 1,074,701	$ 3,804,693
47	1835	Overhead Conductors & Devices	$ 2,745,106	$ 262,884	$ 42,061	$ 3,050,051	-$ 562,383	-$ 42,452	-$ 42,061	-$ 646,896	$ 2,403,155
47	1840	Underground Conduit	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1845	Underground Conductors & Devices	$ 292,254	$ -	$ -	$ 292,254	-$ 153,148	-$ 6,780	$ -	-$ 159,928	$ 132,326
47	1850	Line Transformers	$ 2,681,388	$ 95,830	$ 19,166	$ 2,796,384	-$ 916,083	-$ 63,646	-$ 19,166	-$ 998,895	$ 1,797,489
47	1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1860	Meters (Smart Meters)	$ 1,976,335	$ 2,015,149	$ 403,030	$ 4,394,514	-$ 348,016	-$ 178,711	-$ 403,030	-$ 929,757	$ 3,464,757
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ 13,424,562	$ 2,285,692	$ -	$ 15,710,254	-$ 3,503,910	-$ 291,237	$ -	-$ 3,795,147	$ 11,915,107
13	1910	Leasehold Improvements	$ 115,183	$ -	$ -	$ 115,183	-$ 116,398	-$ 11,518	$ -	-$ 127,916	-$ 12,733
8	1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 27,337	$ 6,500	$ -	$ 33,837	-$ 12,813	-$ 6,093	$ -	-$ 18,906	$ 14,931
10	1930	Transportation Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 86,802	$ 19,500	$ 9,841	$ 116,143	-$ 37,030	-$ 9,791	-$ 9,841	-$ 56,662	$ 59,481
8	1945	Measurement & Testing Equipment	$ 77,554	$ 19,500	$ 7,810	$ 104,864	-$ 43,310	-$ 12,442	-$ 7,810	-$ 63,562	$ 41,302
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 20,332	$ -	$ -	$ 20,332	-$ 21,019	$ -	$ -	-$ 21,019	-$ 687
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 374,668	$ 84,500	$ 111,269	$ 570,437	-$ 192,213	-$ 40,247	-$ 111,269	-$ 343,729	$ 226,708
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 80,237,219**	**$ 12,503,369**	**$ 2,955,105**	**$ 95,695,693**	**-$ 33,184,347**	**-$ 3,243,773**	**-$ 2,955,105**	**-$ 39,383,225**	**$ 56,312,468**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 80,237,219**	**$ 12,503,369**	**$ 2,955,105**	**$ 95,695,693**	**-$ 33,184,347**	**-$ 3,243,773**	**-$ 2,955,105**	**-$ 39,383,225**	**$ 56,312,468**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 3,243,773**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 3,243,773**

Appendix 2-C
Depreciation and Amortization Expense

General: This appendix is to assess the reasonability of the depreciation expense that is included in rate base via. accumulated depreciation and the revenue requirement.
Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Balances presented in the table should exclude asset retirement obligations (AROs) and the related
This appendix must be completed under MIFRS for each year for the earlier of:

Notes:
1 This should include assets in column A (excel column C) that become fully depreciated.
2 The useful life used should be consistent with the OEB's regulatory accounting policies as set out in the Accounting Procedures Handbook for Electricity Distributors, effective Jan. 1, 2012 and also with the Report of the Board, Transition
3 OEB policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. Deviations from this standard practice must be supported in the application.
4 The applicant must provide an explanation of material variances in its evidence.

Year 2018

		Book Values				Service Lives		Depreciation Expense		
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [4]**
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1615	Land	$ 407,800	$ 407,800	$ -	$ -		0.00%	$ -	$ -	$ -
1620	Buildings &Fixtures	$ 5,737,693	$ 637,840	$ 275,077	$ 5,237,391	35.00	2.86%	$ 149,640	$ 155,672	$ 6,032
1650	Reservoirs Dams & Water	$ 670,778	$ 670,778	$ -	$ 0		0.00%	$ -	$ -	$ -
1665	Fuel Holders Produce	$ 7,352,566	$ -	$ 473,969	$ 7,589,551	35.00	2.86%	$ 216,844	$ 223,350	$ 6,506
1670	Prime Movers	$ 16,705,999	$ 2,517,845	$ 1,580,646	$ 14,978,477	10.00	10.00%	$ 1,497,848	$ 1,175,596	-$ 322,252
1675	Generators	$ 8,814,700	$ 1,910,568	$ 459,107	$ 7,133,685	16.00	6.25%	$ 445,855	$ 474,993	$ 29,138
1680	Accessory Electc Equ	$ 1,793,348	$ 736,544	$ -	$ 1,056,804	17.00	5.88%	$ 62,165	$ 97,183	$ 35,018
1685	Misc Power Plant Equ	$ 4,203,502	$ 1,436,535	$ 458,033	$ 2,995,984	25.00	4.00%	$ 119,839	$ 133,304	$ 13,465
1805	Land	$ 294,456	$ -	$ -	$ 294,456	-	0.00%	$ -	$ 1,428	$ 1,428
1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	100.00	1.00%	$ 2,341	$ 2,271	-$ 70
1808	Buildings	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 3,406,457	$ 863	$ 170,037	$ 3,490,613	55.00	1.82%	$ 63,466	$ 61,733	-$ 1,733
1835	Overhead Conductors & Devices	$ 2,429,347	$ 0	$ 29,973	$ 2,444,333	50.00	2.00%	$ 48,887	$ 46,892	-$ 1,995
1840	Underground Conduit	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 292,362	$ 20,603	$ -	$ 271,759	30.00	3.33%	$ 9,059	$ 7,699	-$ 1,360
1850	Line Transformers	$ 2,360,780	$ 288	$ 67,867	$ 2,394,425	40.00	2.50%	$ 59,861	$ 57,273	-$ 2,588
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1860	Meters				$ -		0.00%	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 642,553	$ 3	$ 219,071	$ 752,085	15.00	6.67%	$ 50,139	$ 49,264	-$ 875
1905	Land	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 11,327,706	$ -	$ 582,300	$ 11,618,856	50.00	2.00%	$ 232,377	$ 228,244	-$ 4,133
1910	Leasehold Improvements	$ 115,183	$ -	$ -	$ 115,183	7.00	14.29%	$ 16,455	$ 12,993	-$ 3,462
1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ 51,469	$ -	$ -	$ 51,469	7.00	14.29%	$ 7,353	$ 7,353	$ 0
1920	Computer Equipment - Hardware		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 27,715	$ -	$ -	$ 27,715	5.00	20.00%	$ 5,543	$ -	-$ 5,543
1930	Transportation Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1935	Stores Equipment	$ 140,160	$ 13,761	$ -	$ 126,399	8.00	12.50%	$ 15,800	$ 16,838	$ 1,038
1940	Tools, Shop & Garage Equipment	$ 132,086	$ 5,144	$ 17,617	$ 135,750	6.00	16.67%	$ 22,625	$ 18,615	-$ 4,010
1945	Measurement & Testing Equipment	$ 99,327	$ -	$ 7,810	$ 103,232	5.00	20.00%	$ 20,646	$ 14,943	-$ 5,703
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 20,332	$ 20,332	$ -	-$ 0		0.00%	$ -	$ 687	$ 687
1955	Communication Equipment (Smart Meters)			$ -	$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 706,614	$ 2,359	$ 113,494	$ 761,002	5.00	20.00%	$ 152,200	$ 138,972	-$ 13,228
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 67,967,059**	**$ 8,381,263**	**$ 4,455,001**	**$ 61,813,297**			**$ 3,198,943**	**$ 2,925,303**	**-$ 273,640**

Year 2019

Account	Description	Book Values				Service Lives		Depreciation Expense		
		Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1615	Land	$ 407,800	$ 407,800	$ -	$ -		0.00%	$ -	$ -	$ -
1620	Buildings &Fixtures	$ 5,942,152	$ 637,840	$ 282,724	$ 5,445,674	35.00	2.86%	$ 155,591	$ 171,425	$ 15,834
1650	Reservoirs Dams & Water	$ 670,778	$ 670,778	$ -	$ 0		0.00%	$ -	$ -	$ -
1665	Fuel Holders Produce	$ 7,826,535	$ -	$ -	$ 7,826,535	35.00	2.86%	$ 223,615	$ 216,795	-$ 6,820
1670	Prime Movers	$ 16,391,026	$ 2,443,417	$ 1,674,310	$ 14,784,764	10.00	10.00%	$ 1,478,476	$ 1,131,626	-$ 346,850
1675	Generators	$ 8,568,427	$ 1,884,478	$ 467,692	$ 6,917,795	16.00	6.25%	$ 432,362	$ 454,721	$ 22,359
1680	Accessory Electc Equ	$ 1,784,144	$ 744,768	$ -	$ 1,039,376	17.00	5.88%	$ 61,140	$ 97,057	$ 35,917
1685	Misc Power Plant Equ	$ 4,661,535	$ 1,436,535	$ -	$ 3,225,000	25.00	4.00%	$ 129,000	$ 126,313	-$ 2,687
1805	Land	$ 294,456	$ -	$ -	$ 294,456	-	0.00%	$ -	$ -	$ -
1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	100.00	1.00%	$ 2,341	$ 2,271	-$ 70
1808	Buildings	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 3,557,950	$ 863	$ 99,255	$ 3,606,715	55.00	1.82%	$ 65,577	$ 64,291	-$ 1,286
1835	Overhead Conductors & Devices	$ 2,438,079	$ 0	$ 42,040	$ 2,459,099	50.00	2.00%	$ 49,182	$ 47,830	-$ 1,352
1840	Underground Conduit	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 292,254	$ 32,963	$ -	$ 259,291	30.00	3.33%	$ 8,643	$ 7,698	-$ 945
1850	Line Transformers	$ 2,118,279	$ 288	$ 330,852	$ 2,283,417	40.00	2.50%	$ 57,085	$ 58,511	$ 1,426
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1860	Meters				$ -		0.00%	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 822,291	$ 94	$ 349,068	$ 996,731	15.00	6.67%	$ 66,449	$ 69,435	$ 2,986
1905	Land	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 11,910,006	$ -	$ -	$ 11,910,006	50.00	2.00%	$ 238,200	$ 227,173	-$ 11,027
1910	Leasehold Improvements	$ 115,183	$ -	$ -	$ 115,183	7.00	14.29%	$ 16,455	$ 12,993	-$ 3,462
1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ 51,469	$ -	$ -	$ 51,469	7.00	14.29%	$ 7,353	$ 5,226	-$ 2,127
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	5.00	20.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1935	Stores Equipment	$ 140,160	$ -	$ -	$ 140,160	8.00	12.50%	$ 17,520	$ 10,107	-$ 7,413
1940	Tools, Shop & Garage Equipment	$ 121,384	$ 11,838	$ -	$ 109,546	6.00	16.67%	$ 18,258	$ 17,605	-$ 653
1945	Measurement & Testing Equipment	$ 50,107	$ -	$ 50,244	$ 75,229	5.00	20.00%	$ 15,046	$ 13,050	-$ 1,996
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 20,332	$ 20,332	$ -	-$ 0		0.00%	$ -	$ 687	$ 687
1955	Communication Equipment (Smart Meters)			$ -	$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 686,253	$ 33,325	$ 64,775	$ 685,316	5.00	20.00%	$ 137,063	$ 131,954	-$ 5,109
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 69,104,726**	**$ 8,325,319**	**$ 3,360,960**	**$ 62,459,887**			**$ 3,179,356**	**$ 2,866,768**	**-$ 312,588**

Year 2020

Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		Book Values				Service Lives		Depreciation Expense		
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1615	Land	$ 407,800	$ 407,800	$ -	$ -		0.00%	$ -	$ -	$ -
1620	Buildings &Fixtures	$ 6,573,449	$ 637,840	$ 655,230	$ 6,263,224	35.00	2.86%	$ 178,949	$ 174,968	-$ 3,981
1650	Reservoirs Dams & Water	$ 670,778	$ 670,778	$ -	$ 0		0.00%	$ -	$ -	$ -
1665	Fuel Holders Produce	$ 7,826,535	$ -	$ -	$ 7,826,535	35.00	2.86%	$ 223,615	$ 216,795	-$ 6,820
1670	Prime Movers	$ 15,995,996	$ 2,958,223	$ 900,823	$ 13,488,184	10.00	10.00%	$ 1,348,818	$ 1,103,661	-$ 245,157
1675	Generators	$ 8,563,344	$ 1,884,478	$ 300,274	$ 6,829,003	16.00	6.25%	$ 426,813	$ 455,111	$ 28,298
1680	Accessory Electc Equ	$ 1,784,144	$ 744,768	$ -	$ 1,039,376	17.00	5.88%	$ 61,140	$ 97,057	$ 35,917
1685	Misc Power Plant Equ	$ 4,482,986	$ 1,436,535	$ 506,538	$ 3,299,720	25.00	4.00%	$ 131,989	$ 129,799	-$ 2,190
1805	Land	$ 294,456	$ -	$ -	$ 294,456	-	0.00%	$ -	$ -	$ -
1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	100.00	1.00%	$ 2,341	$ 2,271	-$ 70
1808	Buildings	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 3,626,139	$ 857	$ -	$ 3,625,282	55.00	1.82%	$ 65,914	$ 64,535	-$ 1,379
1835	Overhead Conductors & Devices	$ 2,478,401	$ 0	$ 2,961	$ 2,479,881	50.00	2.00%	$ 49,598	$ 51,974	$ 2,376
1840	Underground Conduit	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 292,254	$ 35,555	$ -	$ 256,699	30.00	3.33%	$ 8,557	$ 7,698	-$ 859
1850	Line Transformers	$ 2,446,330	$ 288	$ -	$ 2,446,042	40.00	2.50%	$ 61,151	$ 60,243	-$ 908
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1860	Meters				$ -		0.00%	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 1,142,376	$ 44,482	$ 55,032	$ 1,125,410	15.00	6.67%	$ 75,027	$ 80,091	$ 5,064
1905	Land	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 11,561,433	$ -	$ -	$ 11,561,433	50.00	2.00%	$ 231,229	$ 229,165	-$ 2,064
1910	Leasehold Improvements	$ 115,183	$ 68,062	$ -	$ 47,121	7.00	14.29%	$ 6,732	$ 12,993	$ 6,261
1915	Office Furniture & Equipment (10 years)			$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ 21,700	$ -	$ -	$ 21,700	7.00	14.29%	$ 3,100	$ 3,100	$ -
1920	Computer Equipment - Hardware	$ -	$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ 22,377	$ 11,189	5.00	20.00%	$ 2,238	$ 2,238	$ 0
1930	Transportation Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1935	Stores Equipment	$ 43,220	$ -	$ -	$ 43,220	8.00	12.50%	$ 5,403	$ 2,702	-$ 2,701
1940	Tools, Shop & Garage Equipment	$ 106,854	$ -	$ 34,696	$ 124,202	6.00	16.67%	$ 20,700	$ 16,495	-$ 4,205
1945	Measurement & Testing Equipment	$ 80,389	$ 5,355	$ -	$ 75,034	5.00	20.00%	$ 15,007	$ 15,104	$ 97
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment			$ -	$ -		0.00%	$ -	$ 687	$ 687
1955	Communication Equipment (Smart Meters)	$ 20,332	$ 20,332	$ -	-$ 0		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 653,771	$ 6,446	$ 79,205	$ 686,928	5.00	20.00%	$ 137,386	$ 106,901	-$ 30,485
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 69,421,996**	**$ 8,921,799**	**$ 2,557,136**	**$ 61,778,765**			**$ 3,055,705**	**$ 2,833,588**	**-$ 222,117**

Year 2021

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Service Lives: Depreciation Rate Assets	Depreciation Expense: Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1615	Land	$ 407,800	$ 407,800	$ -	$ -		0.00%	$ -	$ -	$ -
1620	Buildings &Fixtures	$ 6,915,071	$ 637,840	$ 157,605	$ 6,356,033	35.00	2.86%	$ 181,601	$ 176,525	-$ 5,076
1650	Reservoirs Dams & Water	$ 670,778	$ 670,778	$ -	$ 0		0.00%	$ -	$ -	$ -
1665	Fuel Holders Produce	$ 7,826,535	$ -	$ 762,065	$ 8,207,568	35.00	2.86%	$ 234,502	$ 227,068	-$ 7,434
1670	Prime Movers	$ 16,896,819	$ 3,717,164	$ 1,857,809	$ 14,108,560	10.00	10.00%	$ 1,410,856	$ 1,242,046	-$ 168,810
1675	Generators	$ 8,863,618	$ 1,880,281	$ 772,470	$ 7,369,572	16.00	6.25%	$ 460,598	$ 492,267	$ 31,669
1680	Accessory Electc Equ	$ 1,784,144	$ 715,610	$ -	$ 1,068,534	17.00	5.88%	$ 62,855	$ 96,793	$ 33,938
1685	Misc Power Plant Equ	$ 4,989,524	$ 1,436,535	$ 940,629	$ 4,023,304	25.00	4.00%	$ 160,932	$ 177,198	$ 16,266
1805	Land	$ 294,456	$ -	$ -	$ 294,456	-	0.00%	$ -	$ -	$ -
1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	100.00	1.00%	$ 2,341	$ 2,271	-$ 70
1808	Buildings	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 3,625,064	$ 851	$ 516,823	$ 3,882,624	55.00	1.82%	$ 70,593	$ 70,900	$ 307
1835	Overhead Conductors & Devices	$ 2,475,949	$ 0	$ 58,784	$ 2,505,341	50.00	2.00%	$ 50,107	$ 48,633	-$ 1,474
1840	Underground Conduit	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 292,254	$ 38,995	$ -	$ 253,259	30.00	3.33%	$ 8,442	$ 7,698	-$ 744
1850	Line Transformers	$ 2,440,097	$ 288	$ 105,928	$ 2,492,773	40.00	2.50%	$ 62,319	$ 60,873	-$ 1,446
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1860	Meters				$ -		0.00%	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 1,197,408	$ 111,648	$ 117,691	$ 1,144,606	15.00	6.67%	$ 76,307	$ 81,482	$ 5,175
1905	Land	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 11,875,041	$ -	$ 492,183	$ 12,121,133	50.00	2.00%	$ 242,423	$ 238,492	-$ 3,931
1910	Leasehold Improvements	$ 115,183	$ 68,062	$ -	$ 47,121	7.00	14.29%	$ 6,732	$ 12,993	$ 6,261
1915	Office Furniture & Equipment (10 years)		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ 21,700	$ -	$ -	$ 21,700	7.00	14.29%	$ 3,100	$ 1,550	-$ 1,550
1920	Computer Equipment - Hardware		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 22,377	$ -	$ 4,960	$ 24,857	5.00	20.00%	$ 4,971	$ 4,830	-$ 141
1930	Transportation Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1935	Stores Equipment	$ -	$ -	$ -	$ -	8.00	12.50%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 102,928	$ -	$ 5,148	$ 105,502	6.00	16.67%	$ 17,584	$ 17,223	-$ 361
1945	Measurement & Testing Equipment	$ 76,009	$ -	$ -	$ 76,009	5.00	20.00%	$ 15,202	$ 14,131	-$ 1,071
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment			$ -	$ -		0.00%	$ -	$ 687	$ 687
1955	Communication Equipment (Smart Meters)	$ 20,332	$ 20,332	$ -	-$ 0		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 453,269	$ -	$ 28,419	$ 467,479	5.00	20.00%	$ 93,496	$ 84,832	-$ 8,664
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 71,600,482**	**$ 9,706,184**	**$ 5,820,514**	**$ 64,804,555**			**$ 3,164,961**	**$ 3,058,492**	**-$ 106,469**

Year 2022

Account	Description	Book Values: Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense: Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1615	Land	$ 407,800	$ 407,800	$ -	$ -		0.00%	$ -	$ -	$ -
1620	Buildings &Fixtures	$ 7,003,998	$ 637,840	$ 13,997	$ 6,373,156	35.00	2.86%	$ 182,090	$ 159,535	-$ 22,555
1650	Reservoirs Dams & Water	$ 670,778	$ 670,778	$ -	$ 0		0.00%	$ -	$ -	$ -
1665	Fuel Holders Produce	$ 8,470,509	$ -	$ 83,984	$ 8,512,501	35.00	2.86%	$ 243,214	$ 194,536	-$ 48,678
1670	Prime Movers	$ 17,920,522	$ 3,717,164	$ 1,868,651	$ 15,137,684	10.00	10.00%	$ 1,513,768	$ 1,265,364	-$ 248,404
1675	Generators	$ 9,359,892	$ 1,880,281	$ 664,875	$ 7,812,049	16.00	6.25%	$ 488,253	$ 503,824	$ 15,571
1680	Accessory Electc Equ	$ 1,754,986	$ 715,610	$ 269,606	$ 1,174,179	17.00	5.88%	$ 69,069	$ 102,804	$ 33,735
1685	Misc Power Plant Equ	$ 5,930,153	$ 1,436,535	$ 69,987	$ 4,528,612	25.00	4.00%	$ 181,144	$ 172,581	-$ 8,563
1805	Land	$ 294,456	$ -	$ -	$ 294,456	-	0.00%	$ -	$ -	$ -
1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	100.00	1.00%	$ 2,341	$ 2,271	-$ 70
1808	Buildings	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 4,120,577	$ 851	$ 322,457	$ 4,280,954	55.00	1.82%	$ 77,836	$ 75,948	-$ 1,888
1835	Overhead Conductors & Devices	$ 2,533,743	$ 0	$ 251,622	$ 2,659,554	50.00	2.00%	$ 53,191	$ 51,671	-$ 1,520
1840	Underground Conduit	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 292,254	$ 38,995	$ -	$ 253,259	30.00	3.33%	$ 8,442	$ 7,698	-$ 744
1850	Line Transformers	$ 2,544,834	$ 2,344	$ 170,692	$ 2,627,836	40.00	2.50%	$ 65,696	$ 63,297	-$ 2,399
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1860	Meters				$ -		0.00%	$ -	$ -	$ -
1860	Meters (Smart Meters)	$ 1,282,270	$ 111,648	$ 867,581	$ 1,604,413	15.00	6.67%	$ 106,961	$ 94,453	-$ 12,508
1905	Land	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 12,367,224	$ -	$ 1,057,338	$ 12,895,893	50.00	2.00%	$ 257,918	$ 267,655	$ 9,737
1910	Leasehold Improvements	$ 115,183	$ 68,062	$ -	$ 47,121	7.00	14.29%	$ 6,732	$ 12,993	$ 6,261
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	7.00	14.29%	$ -	$ -	$ -
1920	Computer Equipment - Hardware		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 27,337	$ -	$ -	$ 27,337	5.00	20.00%	$ 5,467	$ 5,603	$ 136
1930	Transportation Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1935	Stores Equipment	$ -	$ -	$ -	$ -	8.00	12.50%	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 103,747	$ 36,445	$ 19,500	$ 77,052	6.00	16.67%	$ 12,842	$ 13,306	$ 464
1945	Measurement & Testing Equipment	$ 70,654	$ 12,600	$ 19,500	$ 67,804	5.00	20.00%	$ 13,561	$ 13,981	$ 420
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment			$ -	$ -		0.00%	$ -	$ 687	$ 687
1955	Communication Equipment (Smart Meters)	$ 20,332	$ 20,332	$ -	-$ 0		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 401,500	$ 117,832	$ 91,000	$ 329,168	5.00	20.00%	$ 65,834	$ 67,117	$ 1,283
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 75,926,875**	**$ 9,875,116**	**$ 5,770,790**	**$ 68,937,154**			**$ 3,354,360**	**$ 3,075,324**	**-$ 279,036**

Year 2023

		Book Values				Service Lives		Depreciation Expense		
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [4]**
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1615	Land	$ 407,800	$ 407,800	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1620	Buildings &Fixtures	$ 7,017,995	$ 650,620	$ -	$ 6,367,375	35.00	2.86%	**$ 181,925**	$ 170,538	**-$ 11,387**
1650	Reservoirs Dams & Water	$ 670,778	$ 670,778	$ -	$ 0		0.00%	**$ -**	$ -	**$ -**
1665	Fuel Holders Produce	$ 8,554,493	$ -	$ 839,190	$ 8,974,088	23.00	4.35%	**$ 390,178**	$ 344,830	**-$ 45,348**
1670	Prime Movers	$ 19,041,713	$ 3,717,164	$ 4,169,735	$ 17,409,417	14.00	7.14%	**$ 1,243,530**	$ 1,301,085	**$ 57,555**
1675	Generators	$ 9,758,817	$ 1,880,281	$ 1,628,582	$ 8,692,827	17.00	5.88%	**$ 511,343**	$ 463,076	**-$ 48,267**
1680	Accessory Electc Equ	$ 2,024,592	$ 715,610	$ 294,713	$ 1,456,338	22.00	4.55%	**$ 66,197**	$ 78,879	**$ 12,682**
1685	Misc Power Plant Equ	$ 6,000,140	$ 1,460,526	$ 355,589	$ 4,717,408	33.00	3.03%	**$ 142,952**	$ 139,665	**-$ 3,287**
1805	Land	$ 294,456	$ -	$ -	$ 294,456	-	0.00%	**$ -**	$ -	**$ -**
1806	L&Rights	$ 234,126	$ -	$ -	$ 234,126	65.00	1.54%	**$ 3,602**	$ 3,442	**-$ 160**
1808	Buildings	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 4,410,788	$ 851	$ 426,005	$ 4,622,939	55.00	1.82%	**$ 84,053**	$ 79,341	**-$ 4,712**
1835	Overhead Conductors & Devices	$ 2,745,106	$ 0	$ 262,884	$ 2,876,548	65.00	1.54%	**$ 44,255**	$ 42,452	**-$ 1,803**
1840	Underground Conduit	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1845	Underground Conductors & Devices	$ 292,254	$ 39,194	$ -	$ 253,060	40.00	2.50%	**$ 6,326**	$ 6,780	**$ 454**
1850	Line Transformers	$ 2,681,388	$ 3,731	$ 95,830	$ 2,725,572	40.00	2.50%	**$ 68,139**	$ 63,646	**-$ 4,493**
1855	Services (Overhead & Underground)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1860	Meters				$ -		0.00%	**$ -**	$ -	**$ -**
1860	Meters (Smart Meters)	$ 1,976,335	$ 125,266	$ 2,015,149	$ 2,858,643	12.00	8.33%	**$ 238,220**	$ 178,711	**-$ 59,509**
1905	Land	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 13,424,562	$ -	$ 2,285,692	$ 14,567,408	50.00	2.00%	**$ 291,348**	$ 291,237	**-$ 111**
1910	Leasehold Improvements	$ 115,183	$ 68,062	$ -	$ 47,121	7.00	14.29%	**$ 6,732**	$ 11,518	**$ 4,786**
1915	Office Furniture & Equipment (10 years)	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	7.00	14.29%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware		$ -		$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -		$ -		0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 27,337	$ -	$ 6,500	$ 30,587	5.00	20.00%	**$ 6,117**	$ 6,093	**-$ 24**
1930	Transportation Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1935	Stores Equipment	$ -	$ -	$ -	$ -	8.00	12.50%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 86,802	$ 46,286	$ 19,500	$ 50,266	6.00	16.67%	**$ 8,378**	$ 9,791	**$ 1,413**
1945	Measurement & Testing Equipment	$ 77,554	$ 20,410	$ 19,500	$ 66,894	5.00	20.00%	**$ 13,379**	$ 12,442	**-$ 937**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment			$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1955	Communication Equipment (Smart Meters)	$ 20,332	$ 20,332	$ -	-$ 0		0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 374,668	$ 229,101	$ 84,500	$ 187,817	5.00	20.00%	**$ 37,563**	$ 40,247	**$ 2,684**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 80,237,219**	**$ 10,056,013**	**$ 12,503,369**	**$ 76,432,891**			**$ 3,344,237**	**$ 3,243,773**	**-$ 100,464**

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Bridge Year	2023 Test Year
Other Income/ Deductions	$ 589	$ 691	$ 490	$ 731	$ 238	$ 212
Generation Expenses - Operation	$ 4,290	$ 4,867	$ 4,861	$ 4,587	$ 5,064	$ 4,622
Fuel	$ 29,406	$ 30,251	$ 29,166	$ 34,481	$ 41,200	$ 30,365
Generation Expenses - Maintenance	$ 9,790	$ 9,679	$ 9,373	$ 9,704	$ 9,069	$ 7,952
Other Power Supply Expenses	$ 14	$ 1,463	$ 1,779	$ 1,584	$ 24,080	$ 74,162
Distribution Expenses - Operation	$ 62	$ 108	$ 154	$ 524	$ 561	$ 477
Distribution Expenses - Maintenance	$ 1,696	$ 1,970	$ 2,921	$ 2,066	$ 2,429	$ 3,268
Billing and Collecting	$ 1,812	$ 1,982	$ 1,875	$ 1,408	$ 2,218	$ 2,383
Community Relations	$ 157	$ 703	$ 459	$ 407	$ 675	$ 682
Administrative and General Expenses	$ 1,109	$ 940	$ 924	$ 1,042	$ 2,147	$ 2,293
Taxes Other Than Income Taxes	$ 52	$ 69	$ 64	$ 66	$ 68	$ 70
Other Deductions	$ 51	$ 79	$ 65	$ 71	$ 65	$ 82
Total OM&A Before Capitalization (B)	$ 49,028	$ 52,802	$ 52,131	$ 56,671	$ 87,814	$ 126,568

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Bridge Year	2023 Test Year	Directly Attributable? (Yes/No)	Explanation for Any Change in Treatment of Capitalized Overhead
employee benefits								
costs of site preparation								
initial delivery and handling costs								
costs of testing whether the asset is functioning properly								
professional fees								
administration and other general overhead costs	$ 559	$ 544	$ 588	$ 596	$ 718	$ 723	Yes	Directly attributable to total labour costs charged to capital
Total Capitalized OM&A (A)	$ 559	$ 544	$ 588	$ 596	$ 718	$ 723		

% of Capitalized OM&A (=A/B)	1%	1%	1%	1%	1%	1%		

Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Excluding Loss of Supply and Major Event Days					Including Major Event Days, Excluding Loss of Supply					Including Loss of Supply, Excluding Major Event Days					Including Loss of Supply and Major Event Days				
	2017	2018	2019	2020	2021	2017	2018	2019	2020	2021	2017	2018	2019	2020	2021	2017	2018	2019	2020	2021
SAIDI	7.55	4.94	6.58	8.27	6.73	7.55	4.94	9.85	8.27	6.73	10.25	9.48	8.86	15.06	11.28	10.25	9.48	12.19	15.06	11.28
SAIFI	3.98	2.02	3.69	3.42	3.33	3.98	2.02	3.84	3.42	3.33	11.92	8.98	8.35	9.67	9.25	11.92	8.98	8.51	9.67	9.25

5 Year Historical Average

	Excluding Loss of Supply and Major Event Days	Including Major Event Days, Excluding Loss of Supply	Including Loss of Supply, Excluding Major Event Days	Including Loss of Supply and Major Event Days
SAIDI	6.814	7.470	10.988	11.652
SAIFI	3.289	3.320	9.635	9.667

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2017	2018	2019	2020	2021	Note
Low Voltage Connections	90.0%	90.59%	95.33%	100.00%	100.00%	100.00%	1
High Voltage Connections	90.0%	n/a	n/a	n/a	n/a	n/a	2
Telephone Accessibility	65.0%	100.00%	100.00%	100.00%	100.00%	100.00%	
Appointments Met	90.0%	n/a	n/a	n/a	n/a	n/a	3
Written Response to Enquires	80.0%	100.00%	100.00%	100.00%	100.00%	100.00%	
Emergency Urban Response	80.0%	n/a	n/a	n/a	n/a	n/a	4
Emergency Rural Response	80.0%	98.83%	98.44%	98.95%	99.56%	99.23%	
Telephone Call Abandon Rate	10.0%	n/a	n/a	n/a	n/a	n/a	5
Appointment Scheduling	90.0%	n/a	n/a	n/a	n/a	n/a	3
Rescheduling a Missed Appointment	100.0%	n/a	n/a	n/a	n/a	n/a	3
Billing Accuracy	98.0%	97.89%	97.90%	96.88%	94.28%	89.35%	
Reconnection Performance Standard	85.0%	89.09%	93.33%	95.24%		100.00%	6

1 Connection of new services low voltage does not include connection of micro-embedded generation facilities.
2 Remotes does not have high voltage connections.
3 Remotes does not make appointments with customers. Due to the inaccessibiity of its service territory, work is bundled and
4 Remotes does not have urban response.
5 Call Abandon Rate does not apply to distributors without an IVR.
6 As determined in EB-2011-0021, the reconnection performance standard for Remotes is 2 weeks, to allow for work to be

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
		2018	2019	2020	2021	2022	2023
	Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
4082	Retail Services Revenues	$ -	$ -	$ -			
4084	Service Transaction Requests (STR) Revenues	$ -	$ -	$ -			
4086	SSS Administration Revenue	$ -	$ -	$ -			
4090	Electric Services Incidental to Energy Sales	$ -	$ -	$ -			
4205	Interdepartmental Rents	$ -	$ -	$ -			
4210	Rent from Electric Property	$ -	$ -	$ -			
4215	Other Utility Operating Income	$ -	$ -	$ -			
4220	Other Electric Revenues	$ -	$ -	$ -			
4225	Late Payment Charges	-$ 270	-$ 412	-$ 145	-$ 469	-$ 304	-$ 338
4230	Sales of Water and Water Power	$ -	$ -	$ -			
4235	Miscellaneous Service Revenues	-$ 72	-$ 93	-$ 168	-$ 60	-$ 71	-$ 71
4240	Provision for Rate Refunds	$ -	$ -	$ -			
4245	Government and Other Assistance Directly Credited to Income	$ -	$ -	$ -			
4305	Regulatory Debits	$ -	$ -	$ -			
4310	Regulatory Credits	$ -	$ -	$ -			
4315	Revenues from Electric Plant Leased to Others	$ -	$ -	$ -			
4320	Expenses of Electric Plant Leased to Others	$ -	$ -	$ -			
4325	Revenues from Merchandise	-$ 1,057	-$ 735	-$ 527	-$ 801	-$ 536	-$ 506
4330	Costs and Expenses of Merchandising	$ 589	$ 395	$ 330	$ 494	$ 238	$ 212
4335	Profits and Losses from Financial Instrument Hedges	$ -	$ -	$ -			
4340	Profits and Losses from Financial Instrument Investments	$ -	$ -	$ -			
4345	Gains from Disposition of Future Use Utility Plant	$ -	$ -	$ -			
4350	Losses from Disposition of Future Use Utility Plant	$ -	$ -	$ -			
4355	Gain on Disposition of Utility and Other Property	$ -	$ -	$ -			
4357	Gain from Retirement of Utility and Other Property	$ -	$ -	$ -			
4360	Loss on Disposition of Utility and Other Property	$ -	$ -	$ -			
4362	Loss from Retirement of Utility and Other Property	$ -	$ -	$ -			
4365	Gains from Disposition of Allowances for Emission	$ -	$ -	$ -			
4370	Losses from Disposition of Allowances for Emission	$ -	$ -	$ -			
4375	Revenues from Non Rate-Regulated Utility Operations	-$ 16	-$ 17	-$ 18	-$ 19	-$ 20	-$ 22
4380	Expenses of Non Rate-Regulated Utility Operations	$ -	$ -	$ -			
4385	Non Rate-Regulated Utility Rental Income	$ -	$ -	$ -			
4390	Miscellaneous Non-Operating Income	$ -	$ -	$ -			
4395	Rate-Payer Benefit Including Interest	$ -	$ -	$ -			
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ -	$ -			
4405	Interest and Dividend Income	$ -	$ -	$ -			
4410	Lessor's Net Investment in Finance Lease	$ -	$ -	$ -			
4415	Equity in Earnings of Subsidiary Companies	$ -	$ -	$ -			
4420	Share of Profit or Loss of Joint Venture	$ -	$ -	$ -			
Miscellaneous Service Revenues		-$ 72	-$ 93	-$ 168	-$ 60	-$ 71	-$ 71
Late Payment Charges		-$ 270	-$ 412	-$ 145	-$ 469	-$ 304	-$ 338
Other Operating Revenues		$ -	$ -	$ -	$ -	$ -	$ -
Other Income or Deductions		-$ 485	-$ 357	-$ 215	-$ 326	-$ 318	-$ 316
Total		-$ 827	-$ 861	-$ 528	-$ 854	-$ 693	-$ 725

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4082, 4084, 4086, 4090, 4205, 4210, 4215, 4220, 4230, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4357, 4360, 4362, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4410, 4415, 4420

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

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income. Tables for the detailed breakdowns will be generated after cell B101 is filled in.

Example: Account 4405 - Interest and Dividend Income

	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Short-term Investment Interest						
Bank Deposit Interest						
Miscellaneous Interest Revenue						
etc.[1]						
Total	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

1 List and specify any other interest revenue.

2 For applicants rebasing under IFRS for the first time, in the transition year (2014) to IFRS, the applicant is to present information in both MIFRS and CGAAP.

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

Account - 4235 Specific Service Charges						
	2018 Actual[2]	2019 Actual[2]	2020 Actual[2]	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
Account Set up fee/Disconnection/Reconnection fee	-$ 18	-$ 12	-$ 8	-$ 13	-$ 10	-$ 10
Miscellaneous Distribtution (work order close)	-$ 37	-$ 81	-$ 61	-$ 47	-$ 61	-$ 61
Miscellaneous Generation (work order close)	-$ 17	$ -	-$ 99	$ -	$ -	$ -
Total	-$ 72	-$ 93	-$ 168	-$ 60	-$ 71	-$ 71

Account - 4225 Late Payment Charges						
	2018 Actual[2]	2019 Actual[2]	2020 Actual[2]	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
Late Payment Charges (Energy)	-$ 258	-$ 318	-$ 85	-$ 383	-$ 287	-$ 321
Late Payment Charges (Non-Energy)	-$ 12	-$ 94	-$ 60	-$ 86	-$ 17	-$ 17
Total	-$ 270	-$ 412	-$ 145	-$ 469	-$ 304	-$ 338

	2018 Actual[2]	2019 Actual[2]	2020 Actual[2]	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
Total	$ -	$ -	$ -	$ -	$ -	$ -

Account - 4325 Rev from Merchandise and Jobbing						
	2018 Actual[2]	2019 Actual[2]	2020 Actual[2]	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
CIA and Engineering Design	-$ 302	-$ 46	-$ 15	-$ 37	$ -	$ -
Street Lighting	-$ 68	-$ 190	-$ 157	-$ 183	-$ 55	-$ 55
Intercompany Services	-$ 410	-$ 293	-$ 160	-$ 236	-$ 246	-$ 246
Community Assessments	-$ 17	$ -	$ -	$ -	$ -	$ -
Support for ESA and Other	-$ 260	-$ 205	-$ 195	-$ 345	-$ 235	-$ 205
Total	-$ 1,057	-$ 735	-$ 527	-$ 801	-$ 536	-$ 506

Account - 4330 Costs & Exp of Merchandise and Jobbing						
	2018 Actual[2]	2019 Actual[2]	2020 Actual[2]	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
CIA and Engineering Design	$ 289	$ 36	$ 16	$ 34	$ -	$ -
Street Lighting	$ 75	$ 184	$ 152	$ 177	$ 49	$ 49
Community Assessments	$ 16	$ -	$ -	$ -	$ -	$ -
Support for ESA and Other	$ 208	$ 176	$ 163	$ 284	$ 189	$ 163
Total	$ 589	$ 395	$ 330	$ 494	$ 238	$ 212

Account - 4375 Revenue from Non-Ut						
	2018 Actual[2]	2019 Actual[2]	2020 Actual[2]	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**	**USGAAP**
OCI	-$ 16	-$ 17	-$ 18	-$ 19	-$ 20	-$ 22
Total	-$ 16	-$ 17	-$ 18	-$ 19	-$ 20	-$ 22

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

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

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

Distribution System (Total) (Off Grid Communities)

	Calendar Year (for 2023 Cost of Service)	Customers				Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	3,598			Actual	62,492,451	62,492,451		
Historical	2018	Actual	3,669	Board -approved	3652	Actual	66,379,348	66,379,348	Board -approved	62,565,904
Historical	2019	Actual	4,236			Actual	72,056,173	72,056,173		
Historical	2020	Actual	4,279			Actual	82,175,545	82,175,545		
Historical	2021	Actual	4,368			Actual	82,208,199	82,208,199		
Bridge Year	2022	Forecast	4,451			Forecast	86,962,033	86,962,033		
Test Year	2023	Forecast	5,191			Forecast	97,424,814	97,424,814		

Variance Analysis	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Versus Board-approved
	2017				2017			
	2018	2.0%	OEB-approved		2018	6.2%	6.2%	
	2019	15.5%			2019	8.6%	8.6%	
	2020	1.0%			2020	14.0%	14.0%	
	2021	2.1%			2021	0.0%	0.0%	
	2022	1.9%			2022		5.8%	
	2023	16.6%			2023		12.0%	55.7%
	Geometric Mean	7.6%			Geometric Mean	9.6%	9.3%	11.7%

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

1 **Customer Class:** Year Round Residential - R2 Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	*2017*	Actual	2,673		
Historical	*2018*	Actual	2,752	Board -approved	2,695
Historical	*2019*	Actual	3,221		
Historical	*2020*	Actual	3,253		
Historical	*2021*	Actual	3,309		
Bridge Year	*2022*	Forecast	3,372		
Test Year	*2023*	Forecast	3,938		

	Calendar Year (for 2023 Cost of Service)	Consumption (kWh) [(3)]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2017*	Actual	39,383,819	39,383,819		
Historical	*2018*	Actual	42,290,456	42,290,456	Board -approved	38,935,222
Historical	*2019*	Actual	45,777,052	45,777,052		
Historical	*2020*	Actual	52,987,941	52,987,941		
Historical	*2021*	Actual	52,545,331	52,545,331		
Bridge Year	*2022*	Forecast	55,513,150	55,513,150		
Test Year	*2023*	Forecast	62,190,414	62,190,414		

	Calendar Year (for 2023 Cost of Service)	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2017*	Actual	14,734	14,734		
Historical	*2018*	Actual	15,367	15,367	Board -approved	14,447
Historical	*2019*	Actual	14,212	14,212		
Historical	*2020*	Actual	16,289	16,289		
Historical	*2021*	Actual	15,880	15,880		
Bridge Year	*2022*	Forecast	16,463	16,463		
Test Year	*2023*	Forecast	15,792	15,792		

Variance Analysis

Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Consumption Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Per Customer Test Year Versus Board-approved
2017								
2018	3.0%		7.4%	7.4%		4.3%	4.3%	
2019	17.0%		8.2%	8.2%		-7.5%	-7.5%	
2020	1.0%		15.8%	15.8%		14.6%	14.6%	
2021	1.7%		-0.8%	-0.8%		-2.5%	-2.5%	
2022	1.9%			5.6%			3.7%	
2023	16.8%	46.1%		12.0%	59.7%		-4.1%	9.3%
Geometric Mean	8.1%	9.9%	10.1%	9.6%	12.4%	2.5%	1.4%	2.3%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	*2017*	Actual	$ 4,700,779		
Historical	*2018*	Actual	$ 5,170,879	Board -approved	$ 4,708,287
Historical	*2019*	Actual	$ 5,691,888		
Historical	*2020*	Actual	$ 6,687,708		
Historical	*2021*	Actual	$ 6,843,425		
Bridge Year (Foreca	*2022*	Forecast	$ 7,611,885		
Test Year (Forecast	*2023*	Forecast	$ 8,595,574		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018	10.0%	
2019	10.1%	
2020	17.5%	
2021	2.3%	
2022	11.2%	
2023	12.9%	82.6%
Geometric Mean	12.8%	16.2%

2 **Customer Class:** Seasonal Residential - R4

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

	Calendar Year (for 2023 Cost of Service)	Customers				Consumption (kWh) [3] Actual (Weather actual)	Consumption (kWh) Weather-normalized		Weather-normalized	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	144			365,703	365,703			2,540	2,540		
Historical	2018	Actual	143	Board -approved	147	344,013	344,013	Board -approved	312,406	2,406	2,406	Board -approved	2,125
Historical	2019	Actual	147			348,000	348,000			2,367	2,367		
Historical	2020	Actual	146			301,514	301,514			2,065	2,065		
Historical	2021	Actual	145			347,018	347,018			2,393	2,393		
Bridge Year	2022	Forecast	142			380,223	380,223			2,678	2,678		
Test Year	2023	Forecast	142			368,324	368,324			2,594	2,594		

Variance Analysis	Year	Customers Year-over-year	Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus Board-approved
	2017								
	2018	-0.7%		-5.9%	-5.9%		-5.3%	-5.3%	
	2019	2.8%		1.2%	1.2%		-1.6%	-1.6%	
	2020	-0.7%		-13.4%	-13.4%		-12.8%	-12.8%	
	2021	-0.7%		15.1%	15.1%		15.9%	15.9%	
	2022	-2.1%			9.6%			11.9%	
	2023	0.0%	-3.4%		-3.1%	17.9%		-3.1%	22.1%
	Geometric Mean	-0.3%	-0.9%	-1.7%	0.1%	4.2%	-2.0%	0.4%	5.1%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 91,198		
Historical	2018	Actual	$ 90,386	Board -approved	$ 87,433
Historical	2019	Actual	$ 93,168		
Historical	2020	Actual	$ 89,691		
Historical	2021	Actual	$ 97,112		
Bridge Year (Foreca	2022	Forecast	$ 105,667		
Test Year (Forecast	2023	Forecast	$ 107,790		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	-0.9%	
	2019	3.1%	
	2020	-3.7%	
	2021	8.3%	
	2022	8.8%	
	2023	2.0%	23.3%
	Geometric Mean	3.4%	5.4%

3 Customer Class: General Service Single Phase -G1

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	304		
Historical	2018	Actual	302	Board -approved	306
Historical	2019	Actual	314		
Historical	2020	Actual	319		
Historical	2021	Actual	306		
Bridge Year	2022	Forecast	317		
Test Year	2023	Forecast	359		

Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	6,078,977	6,078,977		
Actual	7,020,635	7,020,635	Board -approved	6,427,846
Actual	6,843,100	6,843,100		
Actual	7,148,021	7,148,021		
Actual	7,040,559	7,040,559		
Forecast	7,565,753	7,565,753		
Forecast	8,120,457	8,120,457		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	19,997	19,997		
Actual	23,247	23,247	Board -approved	21,006
Actual	21,793	21,793		
Actual	22,408	22,408		
Actual	23,008	23,008		
Forecast	23,867	23,867		
Forecast	22,620	22,620		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	-0.7%	
	2019	4.0%	
	2020	1.6%	
	2021	-4.1%	
	2022	3.6%	
	2023	13.2%	17.3%
	Geometric Mean	3.4%	4.1%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	15.5%	15.5%	
2019	-2.5%	-2.5%	
2020	4.5%	4.5%	
2021	-1.5%	-1.5%	
2022		7.5%	
2023		7.3%	26.3%
Geometric Mean	5.0%	6.0%	6.0%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	16.3%	16.3%	
2019	-6.3%	-6.3%	
2020	2.8%	2.8%	
2021	2.7%	2.7%	
2022		3.7%	
2023		-5.2%	7.7%
Geometric Mean	4.8%	2.5%	1.9%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 758,830		
Historical	2018	Actual	$ 887,664	Board -approved	$ 810,997
Historical	2019	Actual	$ 883,764		
Historical	2020	Actual	$ 939,304		
Historical	2021	Actual	$ 945,046		
Bridge Year (Foreca	2022	Forecast	$ 1,031,860		
Test Year (Forecast	2023	Forecast	$ 1,128,496		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	17.0%	
	2019	-0.4%	
	2020	6.3%	
	2021	0.6%	
	2022	9.2%	
	2023	9.4%	39.1%
	Geometric Mean	8.3%	8.6%

4 Customer Class: General Service Three Phase -G3

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

Customers

	Calendar Year (for 2023 Cost of Service)				
Historical	2017	Actual	42		
Historical	2018	Actual	43	Board -approved	43
Historical	2019	Actual	50		
Historical	2020	Actual	52		
Historical	2021	Actual	61		
Bridge Year	2022	Forecast	60		
Test Year	2023	Forecast	68		

Consumption (kWh) (3)

	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	4,707,758	4,707,758		
Actual	4,764,790	4,764,790	Board -approved	5,042,005
Actual	5,421,997	5,421,997		
Actual	6,050,805	6,050,805		
Actual	6,736,581	6,736,581		
Forecast	6,442,439	6,442,439		
Forecast	7,104,564	7,104,564		

Consumption (kWh) per Customer

	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	112,089	112,089		
Actual	110,809	110,809	Board -approvec	117,256
Actual	108,440	108,440		
Actual	116,362	116,362		
Actual	110,436	110,436		
Forecast	107,374	107,374		
Forecast	104,479	104,479		

Variance Analysis

Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Consumption Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Per Customer Test Year Versus Board-approved
2017								
2018	2.4%		1.2%	1.2%		-1.1%	-1.1%	
2019	16.3%		13.8%	13.8%		-2.1%	-2.1%	
2020	4.0%		11.6%	11.6%		7.3%	7.3%	
2021	17.3%		11.3%	11.3%		-5.1%	-5.1%	
2022	-1.6%			-4.4%			-2.8%	
2023	13.3%	58.1%		10.3%	40.9%		-2.7%	-10.9%
Geometric Mean	10.1%	12.1%	12.7%	8.6%	9.0%	-0.5%	-1.4%	-2.8%

Revenues

	Calendar Year (for 2023 Cost of Service)				
Historical	2017	Actual	$ 513,745		
Historical	2018	Actual	$ 527,506	Board -approved	$ 553,136
Historical	2019	Actual	$ 633,284		
Historical	2020	Actual	$ 705,636		
Historical	2021	Actual	$ 810,536		
Bridge Year (Foreca	2022	Forecast	$ 791,343		
Test Year (Forecast	2023	Forecast	$ 874,655		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018	2.7%	
2019	20.1%	
2020	11.4%	
2021	14.9%	
2022	-2.4%	
2023	10.5%	58.1%
Geometric Mean	11.2%	12.1%

5 **Customer Class:** Street Lighting

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	7		
Historical	2018	Actual	8	Board -approved	8
Historical	2019	Actual	8		
Historical	2020	Actual	8		
Historical	2021	Actual	8		
Bridge Year	2022	Forecast	8		
Test Year	2023	Forecast	8		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	223,224	223,224		
Actual	239,899	239,899	Board -approved	263,245
Actual	244,323	244,323		
Actual	246,128	246,128		
Actual	252,471	252,471		
Forecast	244,332	244,332		
Forecast	242,931	242,931		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	31,889	31,889		
Actual	29,987	29,987	Board -approved	32,906
Actual	30,540	30,540		
Actual	30,766	30,766		
Actual	31,559	31,559		
Forecast	30,542	30,542		
Forecast	30,366	30,366		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	14.3%	
	2019	0.0%	
	2020	0.0%	
	2021	0.0%	
	2022	0.0%	
	2023	0.0%	0.0%
	Geometric Mean	2.7%	0.0%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	7.5%	7.5%	
2019	1.8%	1.8%	
2020	0.7%	0.7%	
2021	2.6%	2.6%	
2022		-3.2%	
2023		-0.6%	-7.7%
Geometric Mean	4.2%	1.7%	-2.0%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	-6.0%	-6.0%	
2019	1.8%	1.8%	
2020	0.7%	0.7%	
2021	2.6%	2.6%	
2022		-3.2%	
2023		-0.6%	-7.7%
Geometric Mean	-0.3%	-1.0%	-2.0%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 22,659		
Historical	2018	Actual	$ 24,931	Board -approved	$ 27,088
Historical	2019	Actual	$ 25,613		
Historical	2020	Actual	$ 26,144		
Historical	2021	Actual	$ 26,212		
Bridge Year (Foreca	2022	Forecast	$ 27,108		
Test Year (Forecast	2023	Forecast	$ 28,184		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	10.0%	
	2019	2.7%	
	2020	2.1%	
	2021	0.3%	
	2022	3.4%	
	2023	4.0%	4.0%
	Geometric Mean	4.5%	1.0%

6 **Customer Class:** Standard A Residential Road/Rail

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	9		
Historical	2018	Actual	4	Board -approved	8
Historical	2019	Actual	4		
Historical	2020	Actual	4		
Historical	2021	Actual	4		
Bridge Year	2022	Forecast	4		
Test Year	2023	Forecast	4		

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	48,652	48,652		
Actual	38,680	38,680	Board -approved	47,771
Actual	27,664	27,664		
Actual	21,801	21,801		
Actual	23,091	23,091		
Forecast	24,905	24,905		
Forecast	25,282	25,282		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	5,406	5,406		
Actual	9,670	9,670	Board -approved	5,971
Actual	6,916	6,916		
Actual	5,450	5,450		
Actual	5,773	5,773		
Forecast	6,226	6,226		
Forecast	6,321	6,321		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	-55.6%	
	2019	0.0%	
	2020	0.0%	
	2021	0.0%	
	2022	0.0%	
	2023	0.0%	-50.0%
	Geometric Mean	-15.0%	-15.9%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	-20.5%	-20.5%	
2019	-28.5%	-28.5%	
2020	-21.2%	-21.2%	
2021	5.9%	5.9%	
2022		7.9%	
2023		1.5%	-47.1%
Geometric Mean	-22.0%	-12.3%	-14.7%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	78.9%	78.9%	
2019	-28.5%	-28.5%	
2020	-21.2%	-21.2%	
2021	5.9%	5.9%	
2022		7.9%	
2023		1.5%	5.8%
Geometric Mean	2.2%	3.2%	1.4%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 31,327		
Historical	2018	Actual	$ 25,210	Board -approved	$ 31,314
Historical	2019	Actual	$ 18,537		
Historical	2020	Actual	$ 14,520		
Historical	2021	Actual	$ 15,960		
Bridge Year (Foreca	2022	Forecast	$ 17,722		
Test Year (Forecast	2023	Forecast	$ 18,721		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	-19.5%	
	2019	-26.5%	
	2020	-21.7%	
	2021	9.9%	
	2022	11.0%	
	2023	5.6%	-40.2%
	Geometric Mean	-9.8%	-12.1%

7 **Customer Class:** Standard A Residential Air Access   Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	115		
Historical	2018	Actual	114	Board -approved	135
Historical	2019	Actual	117		
Historical	2020	Actual	116		
Historical	2021	Actual	129		
Bridge Year	2022	Forecast	133		
Test Year	2023	Forecast	70		

	Consumption (kWh) [3]			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	1,283,692	1,283,692		
Actual	1,325,854	1,325,854	Board -approved	1,418,887
Actual	1,308,946	1,308,946		
Actual	1,509,131	1,509,131		
Actual	1,586,464	1,586,464		
Forecast	1,736,030	1,736,030		
Forecast	1,204,900	1,204,900		

	Consumption (kWh) per Customer			
	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	11,163	11,163		
Actual	11,630	11,630	Board -approvec	10,510
Actual	11,188	11,188		
Actual	13,010	13,010		
Actual	12,298	12,298		
Forecast	13,053	13,053		
Forecast	17,213	17,213		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018	-0.9%	
2019	2.6%	
2020	-0.9%	
2021	11.2%	
2022	3.1%	
2023	-47.4%	-48.1%
Geometric Mean	-9.5%	-15.1%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	3.3%	3.3%	
2019	-1.3%	-1.3%	
2020	15.3%	15.3%	
2021	5.1%	5.1%	
2022		9.4%	
2023		-30.6%	-15.1%
Geometric Mean	7.3%	-1.3%	-4.0%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	4.2%	4.2%	
2019	-3.8%	-3.8%	
2020	16.3%	16.3%	
2021	-5.5%	-5.5%	
2022		6.1%	
2023		31.9%	63.8%
Geometric Mean	3.3%	9.0%	13.1%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 1,239,338		
Historical	2018	Actual	$ 1,306,555	Board -approved	$ 1,396,850
Historical	2019	Actual	$ 1,309,558		
Historical	2020	Actual	$ 1,534,607		
Historical	2021	Actual	$ 1,662,861		
Bridge Year (Foreca	2022	Forecast	$ 1,858,486		
Test Year (Forecast	2023	Forecast	$ 1,367,696		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018	5.4%	
2019	0.2%	
2020	17.2%	
2021	8.4%	
2022	11.8%	
2023	-26.4%	-2.1%
Geometric Mean	2.0%	-0.5%

8 **Customer Class:** Standard A General Service Road/Rail

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

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	21		
Historical	2018	Actual	20	Board -approved	22
Historical	2019	Actual	20		
Historical	2020	Actual	20		
Historical	2021	Actual	22		
Bridge Year	2022	Forecast	20		
Test Year	2023	Forecast	20		

	Consumption (kWh) (3)				
Year		Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	762,539	762,539		
2018	Actual	777,104	777,104	Board -approved	710,230
2019	Actual	727,215	727,215		
2020	Actual	739,984	739,984		
2021	Actual	793,769	793,769		
2022	Forecast	848,821	848,821		
2023	Forecast	763,778	763,778		

	Consumption (kWh) per Customer				
Year		Actual (Weather actual)	Weather-normalized		Weather-normalized
2017	Actual	36,311	36,311		
2018	Actual	38,855	38,855	Board -approvec	32,283
2019	Actual	36,361	36,361		
2020	Actual	36,999	36,999		
2021	Actual	36,080	36,080		
2022	Forecast	42,441	42,441		
2023	Forecast	38,189	38,189		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018	-4.8%	
2019	0.0%	
2020	0.0%	
2021	10.0%	
2022	-9.1%	
2023	0.0%	-9.1%
Geometric Mean	-1.0%	-2.4%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	1.9%	1.9%	
2019	-6.4%	-6.4%	
2020	1.8%	1.8%	
2021	7.3%	7.3%	
2022		6.9%	
2023		-10.0%	7.5%
Geometric Mean	1.3%	0.0%	1.8%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	7.0%	7.0%	
2019	-6.4%	-6.4%	
2020	1.8%	1.8%	
2021	-2.5%	-2.5%	
2022		17.6%	
2023		-10.0%	18.3%
Geometric Mean	-0.2%	1.0%	4.3%

	Calendar Year (for 2023 Cost of Service)		Revenues		
Historical	2017	Actual	$ 520,830		
Historical	2018	Actual	$ 540,652	Board -approved	$ 494,817
Historical	2019	Actual	$ 506,795		
Historical	2020	Actual	$ 522,585		
Historical	2021	Actual	$ 582,508		
Bridge Year (Foreca	2022	Forecast	$ 640,480		
Test Year (Forecast	2023	Forecast	$ 599,949		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018	3.8%	
2019	-6.3%	
2020	3.1%	
2021	11.5%	
2022	10.0%	
2023	-6.3%	21.2%
Geometric Mean	2.9%	4.9%

9 **Customer Class:** Standard A General - Air Access

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	283		
Historical	2018	Actual	283	Board -approved	288
Historical	2019	Actual	283		
Historical	2020	Actual	288		
Historical	2021	Actual	298		
Bridge Year	2022	Forecast	244		
Test Year	2023	Forecast	112		

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	9,638,087	9,638,087		
Actual	9,577,917	9,577,917	Board -approved	9,408,294
Actual	10,471,060	10,471,060		
Actual	10,408,724	10,408,724		
Actual	10,144,895	10,144,895		
Forecast	10,174,179	10,174,179		
Forecast	7,571,736	7,571,736		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	34,057	34,057		
Actual	33,844	33,844	Board -approved	32,668
Actual	37,000	37,000		
Actual	36,141	36,141		
Actual	34,043	34,043		
Forecast	41,697	41,697		
Forecast	67,605	67,605		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	0.0%	
	2019	0.0%	
	2020	1.8%	
	2021	3.5%	
	2022	-18.1%	
	2023	-54.1%	-61.1%
	Geometric Mean	-16.9%	-21.0%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	-0.6%	-0.6%	
2019	9.3%	9.3%	
2020	-0.6%	-0.6%	
2021	-2.5%	-2.5%	
2022		0.3%	
2023		-25.6%	-19.5%
Geometric Mean	1.7%	-4.7%	-5.3%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	-0.6%	-0.6%	
2019	9.3%	9.3%	
2020	-2.3%	-2.3%	
2021	-5.8%	-5.8%	
2022		22.5%	
2023		62.1%	106.9%
Geometric Mean	0.0%	14.7%	19.9%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 9,528,269		
Historical	2018	Actual	$ 9,531,050	Board -approved	$ 9,502,376
Historical	2019	Actual	$ 10,649,153		
Historical	2020	Actual	$ 10,758,063		
Historical	2021	Actual	$ 10,812,313		
Bridge Year (Foreca	2022	Forecast	$ 11,095,078		
Test Year (Forecast	2023	Forecast	$ 8,600,603		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	0.0%	
	2019	11.7%	
	2020	1.0%	
	2021	0.5%	
	2022	2.6%	
	2023	-22.5%	-9.5%
	Geometric Mean	-2.0%	-2.5%

10 **Customer Class:** Std A Grid

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

	Calendar Year (for 2023 Cost of Service)	Customers				Consumption (kWh) (3)					Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized	Weather-normalized
Historical	2017	Actual	-			Actual	-	-			Actual			
Historical	2018	Actual	-	Board -approved	-	Actual	-	-	Board -approved	-	Actual		Board -approved	
Historical	2019	Actual	72			Actual	886,816	886,816			Actual	12,317	12,317	
Historical	2020	Actual	73			Actual	2,761,496	2,761,496			Actual	37,829	37,829	
Historical	2021	Actual	86			Actual	2,738,020	2,738,020			Actual	31,837	31,837	
Bridge Year	2022	Forecast	151			Forecast	4,032,200	4,032,200			Forecast	26,703	26,703	
Test Year	2023	Forecast	470			Forecast	9,832,428	9,832,428			Forecast	20,920	20,920	

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2017			2017				2017			
	2018			2018				2018			
	2019			2019				2019			
	2020	1.4%		2020	211.4%	211.4%		2020	207.1%	207.1%	
	2021	17.8%		2021	-0.9%	-0.9%		2021	-15.8%	-15.8%	
	2022	75.6%		2022		47.3%		2022		-16.1%	
	2023	211.3%		2023		143.8%		2023		-21.7%	
	Geometric Mean			Geometric Mean				Geometric Mean			

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ -		
Historical	2018	Actual	$ -	Board -approved	-
Historical	2019	Actual	$ 285,821		
Historical	2020	Actual	$ 894,993		
Historical	2021	Actual	$ 917,506		
Bridge Year (Foreca	2022	Forecast	$ 1,380,973		
Test Year (Forecast	2023	Forecast	$ 3,494,002		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018		
	2019		
	2020	213.1%	
	2021	2.5%	
	2022	50.5%	
	2023	153.0%	
	Geometric Mean		

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

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

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

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

Distribution System (Total) (Off Grid Communities)

	Calendar Year (for 2023 Cost of Service)	Customers				Consumption (kWh) [3]				
							Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	3,598			Actual	62,492,451	62,492,451		
Historical	2018	Actual	3,669	Board -approved	3652	Actual	66,379,348	66,379,348	Board -approved	62,565,904
Historical	2019	Actual	3,728			Actual	68,534,268	68,534,268		
Historical	2020	Actual	3,742			Actual	71,841,796	71,841,796		
Historical	2021	Actual	3,806			Actual	71,896,072	71,896,072		
Bridge Year	2022	Forecast	3,379			Forecast	71,111,521	71,111,521		
Test Year	2023	Forecast	2,160			Forecast	51,351,796	51,351,796		

Variance Analysis	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Versus Board-approved
	2017				2017			
	2018	2.0%	OEB-approved		2018	6.2%	6.2%	
	2019	1.6%			2019	3.2%	3.2%	
	2020	0.4%			2020	4.8%	4.8%	
	2021	1.7%			2021	0.1%	0.1%	
	2022	-11.2%			2022		-1.1%	
	2023	-36.1%			2023		-27.8%	-17.9%
	Geometric Mean	-9.7%			Geometric Mean	4.8%	-3.9%	-4.8%

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

1 **Customer Class:** Year Round Residential - R2

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

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	2,673		
Historical	2018	Actual	2,752	Board -approved	2,695
Historical	2019	Actual	2,796		
Historical	2020	Actual	2,803		
Historical	2021	Actual	2,848		
Bridge Year	2022	Forecast	2,509		
Test Year	2023	Forecast	1,592		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	39,383,819	39,383,819		
Actual	42,290,456	42,290,456	Board -approved	38,935,222
Actual	43,499,429	43,499,429		
Actual	46,402,255	46,402,255		
Actual	45,958,221	45,958,221		
Forecast	45,323,417	45,323,417		
Forecast	32,161,719	32,161,719		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	14,734	14,734		
Actual	15,367	15,367	Board -approved	14,447
Actual	15,558	15,558		
Actual	16,554	16,554		
Actual	16,137	16,137		
Forecast	18,064	18,064		
Forecast	20,202	20,202		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	3.0%	
	2019	1.6%	
	2020	0.3%	
	2021	1.6%	
	2022	-11.9%	
	2023	-36.5%	-40.9%
	Geometric Mean	-9.8%	-12.3%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	7.4%	7.4%	
2019	2.9%	2.9%	
2020	6.7%	6.7%	
2021	-1.0%	-1.0%	
2022		-1.4%	
2023		-29.0%	-17.4%
Geometric Mean	5.3%	-4.0%	-4.7%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	4.3%	4.3%	
2019	1.2%	1.2%	
2020	6.4%	6.4%	
2021	-2.5%	-2.5%	
2022		11.9%	
2023		11.8%	39.8%
Geometric Mean	3.1%	6.5%	8.7%

	Calendar Year (for 2023 Cost of Service)		Revenues		
Historical	2017	Actual	$ 4,700,779		
Historical	2018	Actual	$ 5,170,879	Board -approved	$ 4,708,287
Historical	2019	Actual	$ 5,412,604		
Historical	2020	Actual	$ 5,865,993		
Historical	2021	Actual	$ 5,985,050		
Bridge Year (Foreca	2022	Forecast	$ 6,211,212		
Test Year (Forecast)	2023	Forecast	$ 4,462,474		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	10.0%	
	2019	4.7%	
	2020	8.4%	
	2021	2.0%	
	2022	3.8%	
	2023	-28.2%	-5.2%
	Geometric Mean	-1.0%	-1.3%

2 Customer Class: Seasonal Residential - R4

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	144		
Historical	2018	Actual	143	Board -approved	147
Historical	2019	Actual	147		
Historical	2020	Actual	146		
Historical	2021	Actual	145		
Bridge Year	2022	Forecast	142		
Test Year	2023	Forecast	142		

Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	365,703	365,703		
Actual	344,013	344,013	Board -approved	312,406
Actual	348,000	348,000		
Actual	301,514	301,514		
Actual	347,018	347,018		
Forecast	380,223	380,223		
Forecast	368,324	368,324		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	2,540	2,540		
Actual	2,406	2,406	Board -approved	2,125
Actual	2,367	2,367		
Actual	2,065	2,065		
Actual	2,393	2,393		
Forecast	2,678	2,678		
Forecast	2,594	2,594		

Variance Analysis

Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Consumption Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Per Customer Test Year Versus Board-approved
2017								
2018	-0.7%		-5.9%	-5.9%		-5.3%	-5.3%	
2019	2.8%		1.2%	1.2%		-1.6%	-1.6%	
2020	-0.7%		-13.4%	-13.4%		-12.8%	-12.8%	
2021	-0.7%		15.1%	15.1%		15.9%	15.9%	
2022	-2.1%			9.6%			11.9%	
2023	0.0%	-3.4%		-3.1%	17.9%		-3.1%	22.1%
Geometric Mean	-0.3%	-0.9%	-1.7%	0.1%	4.2%	-2.0%	0.4%	5.1%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 91,198		
Historical	2018	Actual	$ 90,386	Board -approved	$ 87,433
Historical	2019	Actual	$ 93,168		
Historical	2020	Actual	$ 89,691		
Historical	2021	Actual	$ 97,112		
Bridge Year (Foreca	2022	Forecast	$ 105,667		
Test Year (Forecast)	2023	Forecast	$ 107,790		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018	-0.9%	
2019	3.1%	
2020	-3.7%	
2021	8.3%	
2022	8.8%	
2023	2.0%	23.3%
Geometric Mean	3.4%	5.4%

3 **Customer Class:** General Service Single Phase -G1

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	304		
Historical	2018	Actual	302	Board -approved	306
Historical	2019	Actual	305		
Historical	2020	Actual	307		
Historical	2021	Actual	295		
Bridge Year	2022	Forecast	271		
Test Year	2023	Forecast	188		

	Calendar Year	Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	6,078,977	6,078,977		
Historical	2018	Actual	7,020,635	7,020,635	Board -approved	6,427,846
Historical	2019	Actual	6,782,168	6,782,168		
Historical	2020	Actual	6,903,312	6,903,312		
Historical	2021	Actual	6,734,109	6,734,109		
Bridge Year	2022	Forecast	6,894,183	6,894,183		
Test Year	2023	Forecast	5,318,055	5,318,055		

	Calendar Year	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	19,997	19,997		
Historical	2018	Actual	23,247	23,247	Board -approved	21,006
Historical	2019	Actual	22,237	22,237		
Historical	2020	Actual	22,486	22,486		
Historical	2021	Actual	22,827	22,827		
Bridge Year	2022	Forecast	25,440	25,440		
Test Year	2023	Forecast	28,288	28,288		

Variance Analysis

Year	Customers Year-over-year	Test Year Versus Board-approved
2017		
2018	-0.7%	
2019	1.0%	
2020	0.7%	
2021	-3.9%	
2022	-8.1%	
2023	-30.6%	-38.6%
Geometric Mean	-9.2%	-11.5%

Year	Consumption Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2017			
2018	15.5%	15.5%	
2019	-3.4%	-3.4%	
2020	1.8%	1.8%	
2021	-2.5%	-2.5%	
2022		2.4%	
2023		-22.9%	-17.3%
Geometric Mean	3.5%	-2.6%	-4.6%

Year	Per Customer Year-over-year (Actual)	Year-over-year (Weather-normalized)	Test Year Versus Board-approved
2017			
2018	16.3%	16.3%	
2019	-4.3%	-4.3%	
2020	1.1%	1.1%	
2021	1.5%	1.5%	
2022		11.4%	
2023		11.2%	34.7%
Geometric Mean	4.5%	7.2%	7.7%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 758,830		
Historical	2018	Actual	$ 887,664	Board -approved	$ 810,997
Historical	2019	Actual	$ 876,169		
Historical	2020	Actual	$ 908,424		
Historical	2021	Actual	$ 905,090		
Bridge Year (Foreca	2022	Forecast	$ 940,240		
Test Year (Forecast)	2023	Forecast	$ 738,800		

Variance Analysis

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018	17.0%	
2019	-1.3%	
2020	3.7%	
2021	-0.4%	
2022	3.9%	
2023	-21.4%	-8.9%
Geometric Mean	-0.5%	-2.3%

4 **Customer Class:** General Service Three Phase -G3

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	42		
Historical	2018	Actual	43	Board -approved	43
Historical	2019	Actual	48		
Historical	2020	Actual	50		
Historical	2021	Actual	57		
Bridge Year	2022	Forecast	50		
Test Year	2023	Forecast	27		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	2.4%	
	2019	11.6%	
	2020	4.2%	
	2021	14.0%	
	2022	-12.3%	
	2023	-46.0%	-37.2%
	Geometric Mean	-8.5%	-11.0%

Consumption (kWh) [3]	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	4,707,758	4,707,758		
Actual	4,764,790	4,764,790	Board -approved	5,042,005
Actual	5,125,463	5,125,463		
Actual	5,308,946	5,308,946		
Actual	6,056,034	6,056,034		
Forecast	5,515,722	5,515,722		
Forecast	3,777,991	3,777,991		

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	1.2%	1.2%	
2019	7.6%	7.6%	
2020	3.6%	3.6%	
2021	14.1%	14.1%	
2022		-8.9%	
2023		-31.5%	-25.1%
Geometric Mean	8.8%	-4.3%	-7.0%

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	112,089	112,089		
Actual	110,809	110,809	Board -approvec	117,256
Actual	106,780	106,780		
Actual	106,179	106,179		
Actual	106,246	106,246		
Forecast	110,314	110,314		
Forecast	139,926	139,926		

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	-1.1%	-1.1%	
2019	-3.6%	-3.6%	
2020	-0.6%	-0.6%	
2021	0.1%	0.1%	
2022		3.8%	
2023		26.8%	19.3%
Geometric Mean	-1.8%	4.5%	4.5%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 513,745		
Historical	2018	Actual	$ 527,506	Board -approved	$ 553,136
Historical	2019	Actual	$ 590,679		
Historical	2020	Actual	$ 618,683		
Historical	2021	Actual	$ 727,866		
Bridge Year (Foreca	2022	Forecast	$ 679,451		
Test Year (Forecast)	2023	Forecast	$ 459,911		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	2.7%	
	2019	12.0%	
	2020	4.7%	
	2021	17.6%	
	2022	-6.7%	
	2023	-32.3%	-16.9%
	Geometric Mean	-2.2%	-4.5%

5 **Customer Class:** Street Lighting

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	7		
Historical	2018	Actual	8	Board -approved	8
Historical	2019	Actual	8		
Historical	2020	Actual	8		
Historical	2021	Actual	8		
Bridge Year	2022	Forecast	6		
Test Year	2023	Forecast	5		

	Consumption (kWh) [(3)] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	223,224	223,224		
Actual	239,899	239,899	Board -approved	263,245
Actual	244,323	244,323		
Actual	246,128	246,128		
Actual	252,471	252,471		
Forecast	214,041	214,041		
Forecast	160,011	160,011		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	31,889	31,889		
Actual	29,987	29,987	Board -approved	32,906
Actual	30,540	30,540		
Actual	30,766	30,766		
Actual	31,559	31,559		
Forecast	35,674	35,674		
Forecast	32,002	32,002		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	14.3%	
	2019	0.0%	
	2020	0.0%	
	2021	0.0%	
	2022	-25.0%	
	2023	-16.7%	-37.5%
	Geometric Mean	-6.5%	-11.1%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	7.5%	7.5%	
2019	1.8%	1.8%	
2020	0.7%	0.7%	
2021	2.6%	2.6%	
2022		-15.2%	
2023		-25.2%	-39.2%
Geometric Mean	4.2%	-6.4%	-11.7%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	-6.0%	-6.0%	
2019	1.8%	1.8%	
2020	0.7%	0.7%	
2021	2.6%	2.6%	
2022		13.0%	
2023		-10.3%	-2.7%
Geometric Mean	-0.3%	0.1%	-0.7%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 22,659		
Historical	2018	Actual	$ 24,931	Board -approved	$ 27,088
Historical	2019	Actual	$ 25,613		
Historical	2020	Actual	$ 26,144		
Historical	2021	Actual	$ 26,212		
Bridge Year (Foreca	2022	Forecast	$ 23,679		
Test Year (Forecast)	2023	Forecast	$ 18,565		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	10.0%	
	2019	2.7%	
	2020	2.1%	
	2021	0.3%	
	2022	-9.7%	
	2023	-21.6%	-31.5%
	Geometric Mean	-3.9%	-9.0%

6 **Customer Class:** Standard A Residential Road/Rail

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

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	9		
Historical	2018	Actual	4	Board -approved	8
Historical	2019	Actual	4		
Historical	2020	Actual	4		
Historical	2021	Actual	4		
Bridge Year	2022	Forecast	4		
Test Year	2023	Forecast	4		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	48,652	48,652		
Actual	38,680	38,680	Board -approved	47,771
Actual	27,664	27,664		
Actual	21,801	21,801		
Actual	23,091	23,091		
Forecast	24,905	24,905		
Forecast	25,282	25,282		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	5,406	5,406		
Actual	9,670	9,670	Board -approved	5,971
Actual	6,916	6,916		
Actual	5,450	5,450		
Actual	5,773	5,773		
Forecast	6,226	6,226		
Forecast	6,321	6,321		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	-55.6%	
	2019	0.0%	
	2020	0.0%	
	2021	0.0%	
	2022	0.0%	
	2023	0.0%	-50.0%
	Geometric Mean	-15.0%	-15.9%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	-20.5%	-20.5%	
2019	-28.5%	-28.5%	
2020	-21.2%	-21.2%	
2021	5.9%	5.9%	
2022		7.9%	
2023		1.5%	-47.1%
Geometric Mean	-22.0%	-12.3%	-14.7%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	78.9%	78.9%	
2019	-28.5%	-28.5%	
2020	-21.2%	-21.2%	
2021	5.9%	5.9%	
2022		7.9%	
2023		1.5%	5.8%
Geometric Mean	2.2%	3.2%	1.4%

	Calendar Year (for 2023 Cost of Service)		Revenues		
Historical	2017	Actual	$ 31,327		
Historical	2018	Actual	$ 25,210	Board -approved	$ 31,314
Historical	2019	Actual	$ 18,537		
Historical	2020	Actual	$ 14,520		
Historical	2021	Actual	$ 15,960		
Bridge Year (Foreca	2022	Forecast	$ 17,722		
Test Year (Forecast)	2023	Forecast	$ 18,721		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	-19.5%	
	2019	-26.5%	
	2020	-21.7%	
	2021	9.9%	
	2022	11.0%	
	2023	5.6%	-40.2%
	Geometric Mean	-9.8%	-12.1%

7 Customer Class: Standard A Residential Air Access

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

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	115		
Historical	2018	Actual	114	Board -approved	135
Historical	2019	Actual	117		
Historical	2020	Actual	116		
Historical	2021	Actual	129		
Bridge Year	2022	Forecast	133		
Test Year	2023	Forecast	70		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	1,283,692	1,283,692		
Actual	1,325,854	1,325,854	Board -approved	1,418,887
Actual	1,308,946	1,308,946		
Actual	1,509,131	1,509,131		
Actual	1,586,464	1,586,464		
Forecast	1,736,030	1,736,030		
Forecast	1,204,900	1,204,900		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	11,163	11,163		
Actual	11,630	11,630	Board -approvec	10,510
Actual	11,188	11,188		
Actual	13,010	13,010		
Actual	12,298	12,298		
Forecast	13,053	13,053		
Forecast	17,213	17,213		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	-0.9%	
	2019	2.6%	
	2020	-0.9%	
	2021	11.2%	
	2022	3.1%	
	2023	-47.4%	-48.1%
	Geometric Mean	-9.5%	-15.1%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	3.3%	3.3%	
2019	-1.3%	-1.3%	
2020	15.3%	15.3%	
2021	5.1%	5.1%	
2022		9.4%	
2023		-30.6%	-15.1%
Geometric Mean	7.3%	-1.3%	-4.0%

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	4.2%	4.2%	
2019	-3.8%	-3.8%	
2020	16.3%	16.3%	
2021	-5.5%	-5.5%	
2022		6.1%	
2023		31.9%	63.8%
Geometric Mean	3.3%	9.0%	13.1%

	Calendar Year (for 2023 Cost of Service)		Revenues		
Historical	2017	Actual	$ 1,239,338		
Historical	2018	Actual	$ 1,306,555	Board -approved	$ 1,396,850
Historical	2019	Actual	$ 1,309,558		
Historical	2020	Actual	$ 1,534,607		
Historical	2021	Actual	$ 1,662,861		
Bridge Year (Foreca	2022	Forecast	$ 1,858,486		
Test Year (Forecast)	2023	Forecast	$ 1,367,696		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	5.4%	
	2019	0.2%	
	2020	17.2%	
	2021	8.4%	
	2022	11.8%	
	2023	-26.4%	-2.1%
	Geometric Mean	2.0%	-0.5%

8 **Customer Class:** Standard A General Service Road/Rail

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

	Calendar Year (for 2023 Cost of Service)	Customers				Consumption (kWh) (3) Actual (Weather actual)	Weather-normalized		Weather-normalized	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	21			Actual	762,539	762,539			Actual	36,311	36,311		
Historical	2018	Actual	20	Board -approved	22	Actual	777,104	777,104	Board -approved	710,230	Actual	38,855	38,855	Board -approvec	32,283
Historical	2019	Actual	20			Actual	727,215	727,215			Actual	36,361	36,361		
Historical	2020	Actual	20			Actual	739,984	739,984			Actual	36,999	36,999		
Historical	2021	Actual	22			Actual	793,769	793,769			Actual	36,080	36,080		
Bridge Year	2022	Forecast	20			Forecast	848,821	848,821			Forecast	42,441	42,441		
Test Year	2023	Forecast	20			Forecast	763,778	763,778			Forecast	38,189	38,189		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2017			2017				2017			
	2018	-4.8%		2018	1.9%	1.9%		2018	7.0%	7.0%	
	2019	0.0%		2019	-6.4%	-6.4%		2019	-6.4%	-6.4%	
	2020	0.0%		2020	1.8%	1.8%		2020	1.8%	1.8%	
	2021	10.0%		2021	7.3%	7.3%		2021	-2.5%	-2.5%	
	2022	-9.1%		2022		6.9%		2022		17.6%	
	2023	0.0%	-9.1%	2023		-10.0%	7.5%	2023		-10.0%	18.3%
	Geometric Mean	-1.0%	-2.4%	Geometric Mean	1.3%	0.0%	1.8%	Geometric Mean	-0.2%	1.0%	4.3%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 520,830		
Historical	2018	Actual	$ 540,652	Board -approved	$ 494,817
Historical	2019	Actual	$ 506,795		
Historical	2020	Actual	$ 522,585		
Historical	2021	Actual	$ 582,508		
Bridge Year (Foreca	2022	Forecast	$ 640,480		
Test Year (Forecast)	2023	Forecast	$ 599,949		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	3.8%	
	2019	-6.3%	
	2020	3.1%	
	2021	11.5%	
	2022	10.0%	
	2023	-6.3%	21.2%
	Geometric Mean	2.9%	4.9%

9 **Customer Class:** Standard A General - Air Access

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	283		
Historical	2018	Actual	283	Board -approved	288
Historical	2019	Actual	283		
Historical	2020	Actual	288		
Historical	2021	Actual	298		
Bridge Year	2022	Forecast	244		
Test Year	2023	Forecast	112		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	0.0%	
	2019	0.0%	
	2020	1.8%	
	2021	3.5%	
	2022	-18.1%	
	2023	-54.1%	-61.1%
	Geometric Mean	-16.9%	-21.0%

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	9,638,087	9,638,087		
Actual	9,577,917	9,577,917	Board -approved	9,408,294
Actual	10,471,060	10,471,060		
Actual	10,408,724	10,408,724		
Actual	10,144,895	10,144,895		
Forecast	10,174,179	10,174,179		
Forecast	7,571,736	7,571,736		

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	-0.6%	-0.6%	
2019	9.3%	9.3%	
2020	-0.6%	-0.6%	
2021	-2.5%	-2.5%	
2022		0.3%	
2023		-25.6%	-19.5%
Geometric Mean	1.7%	-4.7%	-5.3%

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	34,057	34,057		
Actual	33,844	33,844	Board -approved	32,668
Actual	37,000	37,000		
Actual	36,141	36,141		
Actual	34,043	34,043		
Forecast	41,697	41,697		
Forecast	67,605	67,605		

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018	-0.6%	-0.6%	
2019	9.3%	9.3%	
2020	-2.3%	-2.3%	
2021	-5.8%	-5.8%	
2022		22.5%	
2023		62.1%	106.9%
Geometric Mean	0.0%	14.7%	19.9%

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ 9,528,269		
Historical	2018	Actual	$ 9,531,050	Board -approved	$ 9,502,376
Historical	2019	Actual	$ 10,649,153		
Historical	2020	Actual	$ 10,758,063		
Historical	2021	Actual	$ 10,812,313		
Bridge Year (Foreca	2022	Forecast	$ 11,095,078		
Test Year (Forecast)	2023	Forecast	$ 8,600,603		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018	0.0%	
	2019	11.7%	
	2020	1.0%	
	2021	0.5%	
	2022	2.6%	
	2023	-22.5%	-9.5%
	Geometric Mean	-2.0%	-2.5%

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

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

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

Distribution System (Total) (Off Grid Communities)

	Calendar Year (for 2023 Cost of Service)	Customers				Consumption (kWh) [3]				
							Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	-			Actual	-	-		
Historical	2018	Actual	-	Board -approved	0	Actual	-	-	Board -approved	-
Historical	2019	Actual	508			Actual	3,521,905	3,521,905		
Historical	2020	Actual	537			Actual	10,333,749	10,333,749		
Historical	2021	Actual	562			Actual	10,312,127	10,312,127		
Bridge Year	2022	Forecast	1,072			Forecast	15,850,512	15,850,512		
Test Year	2023	Forecast	3,031			Forecast	46,073,018	46,073,018		

Variance Analysis	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year			Versus Board-approved
	2017				2017				
	2018		OEB-approved		2018				
	2019				2019				
	2020	5.7%			2020	193.4%	193.4%		
	2021	4.7%			2021	-0.2%	-0.2%		
	2022	90.7%			2022		53.7%		
	2023	182.7%			2023		190.7%		
	Geometric Mean				Geometric Mean				

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

1 **Customer Class:** Year Round Residential - R2   Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	-		
Historical	2018	Actual	-	Board -approved	
Historical	2019	Actual	425		
Historical	2020	Actual	450		
Historical	2021	Actual	461		
Bridge Year	2022	Forecast	863		
Test Year	2023	Forecast	2,346		

	Calendar Year		Consumption (kWh) (3) Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	-	-		
Historical	2018	Actual	-	-	Board -approved	
Historical	2019	Actual	2,277,623	2,277,623		
Historical	2020	Actual	6,585,686	6,585,686		
Historical	2021	Actual	6,587,110	6,587,110		
Bridge Year	2022	Forecast	10,189,734	10,189,734		
Test Year	2023	Forecast	30,028,695	30,028,695		

	Calendar Year		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual				
Historical	2018	Actual			Board -approved	
Historical	2019	Actual	5,359	5,359		
Historical	2020	Actual	14,635	14,635		
Historical	2021	Actual	14,289	14,289		
Bridge Year	2022	Forecast	11,807	11,807		
Test Year	2023	Forecast	12,800	12,800		

Variance Analysis	Year	Customers Year-over-year	Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Test Year Versus Board-approved
	2017								
	2018								
	2019								
	2020	5.9%		189.1%	189.1%		173.1%	173.1%	
	2021	2.4%		0.0%	0.0%		-2.4%	-2.4%	
	2022	87.2%			54.7%			-17.4%	
	2023	171.8%			194.7%			8.4%	
	Geometric Mean								

	Calendar Year (for 2023 Cost of Service)		Revenues		
Historical	2017	Actual	$ -		
Historical	2018	Actual	$ -	Board -approved	$ -
Historical	2019	Actual	$ 279,284		
Historical	2020	Actual	$ 821,716		
Historical	2021	Actual	$ 858,375		
Bridge Year (Foreca	2022	Forecast	$ 1,400,673		
Test Year (Forecast)	2023	Forecast	$ 4,133,100		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018		
	2019		
	2020	194.2%	
	2021	4.5%	
	2022	63.2%	
	2023	195.1%	
	Geometric Mean		

2 **Customer Class:** General Service Single Phase -G1

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

	Calendar Year (for 2023 Cost of Service)	Customers				Consumption (kWh) [3]						Consumption (kWh) per Customer			
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	-			Actual	-	-			Actual				
Historical	2018	Actual	-	Board -approved	0	Actual	-	-	Board -approved	-	Actual			Board -approved	
Historical	2019	Actual	9			Actual	60,932	60,932			Actual	6,770	6,770		
Historical	2020	Actual	12			Actual	244,709	244,709			Actual	20,392	20,392		
Historical	2021	Actual	11			Actual	306,450	306,450			Actual	27,859	27,859		
Bridge Year	2022	Forecast	46			Forecast	671,570	671,570			Forecast	14,599	14,599		
Test Year	2023	Forecast	171			Forecast	2,802,402	2,802,402			Forecast	16,388	16,388		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved	Year	Year-over-year		Test Year Versus Board-approved
	2017			2017				2017			
	2018			2018				2018			
	2019			2019				2019			
	2020	33.3%		2020	301.6%	301.6%		2020	201.2%	201.2%	
	2021	-8.3%		2021	25.2%	25.2%		2021	36.6%	36.6%	
	2022	318.2%		2022		119.1%		2022		-47.6%	
	2023	271.7%		2023		317.3%		2023		12.3%	
	Geometric Mean			Geometric Mean				Geometric Mean			

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ -		
Historical	2018	Actual	$ -	Board -approved	
Historical	2019	Actual	$ 7,594		
Historical	2020	Actual	$ 30,880		
Historical	2021	Actual	$ 39,956		
Bridge Year (Foreca	2022	Forecast	$ 91,621		
Test Year (Forecast)	2023	Forecast	$ 389,696		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018		
	2019		
	2020	306.6%	
	2021	29.4%	
	2022	129.3%	
	2023	325.3%	
	Geometric Mean		

3 **Customer Class:** General Service Three Phase -G3

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

	Calendar Year (for 2023 Cost of Service)	Customers			
Historical	2017	Actual	-		
Historical	2018	Actual	-	Board -approved	
Historical	2019	Actual	2		
Historical	2020	Actual	2		
Historical	2021	Actual	4		
Bridge Year	2022	Forecast	10		
Test Year	2023	Forecast	41		

	Consumption (kWh) [3] Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	-	-		
Actual	-	-	Board -approved	-
Actual	296,534	296,534		
Actual	741,858	741,858		
Actual	680,547	680,547		
Forecast	926,717	926,717		
Forecast	3,326,573	3,326,573		

	Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual				
Actual			Board -approved	
Actual	148,267	148,267		
Actual	370,929	370,929		
Actual	170,137	170,137		
Forecast	92,672	92,672		
Forecast	81,136	81,136		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018		
	2019		
	2020	0.0%	
	2021	100.0%	
	2022	150.0%	
	2023	310.0%	
	Geometric Mean		

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018			
2019			
2020	150.2%	150.2%	
2021	-8.3%	-8.3%	
2022		36.2%	
2023		259.0%	
Geometric Mean			

Year	Year-over-year		Test Year Versus Board-approved
2017			
2018			
2019			
2020	150.2%	150.2%	
2021	-54.1%	-54.1%	
2022		-45.5%	
2023		-12.4%	
Geometric Mean			

	Calendar Year (for 2023 Cost of Service)	Revenues			
Historical	2017	Actual	$ -		
Historical	2018	Actual	$ -	Board -approved	$ -
Historical	2019	Actual	$ 42,605		
Historical	2020	Actual	$ 86,952		
Historical	2021	Actual	$ 82,670		
Bridge Year (Foreca	2022	Forecast	$ 111,892		
Test Year (Forecast)	2023	Forecast	$ 414,744		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018		
	2019		
	2020	104.1%	
	2021	-4.9%	
	2022	35.3%	
	2023	270.7%	
	Geometric Mean		

4 **Customer Class:** Street Lighting

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

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	-		
Historical	2018	Actual	-	Board -approved	0
Historical	2019	Actual	-		
Historical	2020	Actual	-		
Historical	2021	Actual	-		
Bridge Year	2022	Forecast	2		
Test Year	2023	Forecast	3		

Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual	-	-		
Actual	-	-	Board -approved	-
Actual	-	-		
Actual	-	-		
Actual	-	-		
Forecast	30,291	30,291		
Forecast	82,920	82,920		

Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Actual				
Actual			Board -approved	
Actual				
Actual				
Actual				
Forecast	15,146	15,146		
Forecast	27,640	27,640		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018		
	2019		
	2020		
	2021		
	2022		
	2023	50.0%	
	Geometric Mean		

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018		
2019		
2020		
2021		
2022		
2023	173.7%	
Geometric Mean		

Year	Year-over-year	Test Year Versus Board-approved
2017		
2018		
2019		
2020		
2021		
2022		
2023	82.5%	
Geometric Mean		

	Calendar Year (for 2023 Cost of Service)		Revenues		
Historical	2017	Actual	$ -		
Historical	2018	Actual	$ -	Board -approved	$ -
Historical	2019	Actual	$ -		
Historical	2020	Actual	$ -		
Historical	2021	Actual	$ -		
Bridge Year (Foreca	2022	Forecast	$ 3,429		
Test Year (Forecast)	2023	Forecast	$ 9,619		

Variance Analysis	Year	Year-over-year	Test Year Versus Board-approved
	2017		
	2018		
	2019		
	2020		
	2021		
	2022		
	2023	180.5%	
	Geometric Mean		

5 **Customer Class:** Std A Grid

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

	Calendar Year (for 2023 Cost of Service)		Customers		
Historical	2017	Actual	-		
Historical	2018	Actual	-	Board -approved	-
Historical	2019	Actual	72		
Historical	2020	Actual	73		
Historical	2021	Actual	86		
Bridge Year	2022	Forecast	151		
Test Year	2023	Forecast	470		

	Calendar Year		Consumption (kWh) (3) Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual	-	-		
Historical	2018	Actual	-	-	Board -approved	-
Historical	2019	Actual	886,816	886,816		
Historical	2020	Actual	2,761,496	2,761,496		
Historical	2021	Actual	2,738,020	2,738,020		
Bridge Year	2022	Forecast	4,032,200	4,032,200		
Test Year	2023	Forecast	9,832,428	9,832,428		

	Calendar Year		Consumption (kWh) per Customer Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2017	Actual				
Historical	2018	Actual			Board -approved	
Historical	2019	Actual	12,317	12,317		
Historical	2020	Actual	37,829	37,829		
Historical	2021	Actual	31,837	31,837		
Bridge Year	2022	Forecast	26,703	26,703		
Test Year	2023	Forecast	20,920	20,920		

Variance Analysis

Year	Customers Year-over-year	Customers Test Year Versus Board-approved	Consumption Year-over-year (Actual)	Consumption Year-over-year (Weather-normalized)	Consumption Test Year Versus Board-approved	Per Customer Year-over-year (Actual)	Per Customer Year-over-year (Weather-normalized)	Per Customer Test Year Versus Board-approved
2017								
2018								
2019								
2020	1.4%		211.4%	211.4%		207.1%	207.1%	
2021	17.8%		-0.9%	-0.9%		-15.8%	-15.8%	
2022	75.6%			47.3%			-16.1%	
2023	211.3%			143.8%			-21.7%	
Geometric Mean								

	Calendar Year (for 2023 Cost of Service)		Revenues		
Historical	2017	Actual	$ -		
Historical	2018	Actual	$ -	Board -approved	$ -
Historical	2019	Actual	$ 285,821		
Historical	2020	Actual	$ 894,993		
Historical	2021	Actual	$ 917,506		
Bridge Year (Foreca	2022	Forecast	$ 1,380,973		
Test Year (Forecast)	2023	Forecast	$ 3,494,002		

Variance Analysis Year	Year-over-year	Test Year Versus Board-approved
2017		
2018		
2019		
2020	213.1%	
2021	2.5%	
2022	50.5%	
2023	153.0%	
Geometric Mean		

File Number: EB-2022-0041
Exhibit:
Tab:
Schedule:
Page:

Date:

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

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

Customers/Connections - Total

Rate Class*	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential	2,673	2,752	3,221	3,253	3,309	3,372	3,938
Non Std A - Seasonal	144	143	147	146	145	142	142
Non Std A - General 1-Phase	304	302	314	319	306	317	359
Non Std A - General 3-Phase	42	43	50	52	61	60	68
Street Lighting	7	8	8	8	8	8	8
Std A - Residential-Road	9	4	4	4	4	4	4
Std A - Residential-Air	115	114	117	116	129	133	70
Std A - General-Road	21	20	20	20	22	20	20
Std A - General-Air	283	283	283	288	298	244	112
Std A - Grid Connected	-	-	72	73	86	151	470

Customers/Connections Variance Analysis

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential		3%	17%	1%	2%	2%	17%
Non Std A - Seasonal		-1%	3%	-1%	-1%	-2%	0%
Non Std A - General 1-Phase		-1%	4%	2%	-4%	4%	13%
Non Std A - General 3-Phase		2%	16%	4%	17%	-2%	13%
Street Lighting		14%	0%	0%	0%	0%	0%
Std A - Residential-Road		-56%	0%	0%	0%	0%	0%
Std A - Residential-Air		-1%	3%	-1%	11%	3%	-47%
Std A - General-Road		-5%	0%	0%	10%	-9%	0%
Std A - General-Air		0%	0%	2%	3%	-18%	-54%
Std A - Grid Connected		0%	0%	1%	18%	76%	211%

Customers/Connections - Grid

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential			425	450	461	863	2,346
Non Std A - Seasonal							
Non Std A - General 1-Phase			9	12	11	46	171
Non Std A - General 3-Phase			2	2	4	10	41
Street Lighting						2	3
Std A - Residential-Road							
Std A - Residential-Air							
Std A - General-Road							
Std A - General-Air							
Std A - Grid Connected			72	73	86	151	470

Customers/Connections Variance Analysis

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential		0%	0%	6%	2%	87%	172%
Non Std A - Seasonal		0%	0%	0%	0%	0%	0%
Non Std A - General 1-Phase		0%	0%	33%	-8%	318%	272%
Non Std A - General 3-Phase		0%	0%	0%	100%	150%	310%
Street Lighting		0%	0%	0%	0%	0%	50%
Std A - Residential-Road		0%	0%	0%	0%	0%	0%
Std A - Residential-Air		0%	0%	0%	0%	0%	0%
Std A - General-Road		0%	0%	0%	0%	0%	0%
Std A - General-Air		0%	0%	0%	0%	0%	0%
Std A - Grid Connected		0%	0%	1%	18%	76%	211%

Customers/Connections - Off Grid

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential	2,673	2,752	2,796	2,803	2,848	2,509	1,592
Non Std A - Seasonal	144	143	147	146	145	142	142
Non Std A - General 1-Phase	304	302	305	307	295	271	188
Non Std A - General 3-Phase	42	43	48	50	57	50	27
Street Lighting	7	8	8	8	8	6	5
Std A - Residential-Road	9	4	4	4	4	4	4
Std A - Residential-Air	115	114	117	116	129	133	70
Std A - General-Road	21	20	20	20	22	20	20
Std A - General-Air	283	283	283	288	298	244	112
Std A - Grid Connected							

Customers/Connections Variance Analysis

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential		3%	2%	0%	2%	-12%	-37%
Non Std A - Seasonal		-1%	3%	-1%	-1%	-2%	0%
Non Std A - General 1-Phase		-1%	1%	1%	-4%	-8%	-31%
Non Std A - General 3-Phase		2%	12%	4%	14%	-12%	-46%
Street Lighting		14%	0%	0%	0%	-25%	-17%
Std A - Residential-Road		-56%	0%	0%	0%	0%	0%
Std A - Residential-Air		-1%	3%	-1%	11%	3%	-47%
Std A - General-Road		-5%	0%	0%	10%	-9%	0%
Std A - General-Air		0%	0%	2%	3%	-18%	-54%
Std A - Grid Connected		0%	0%	0%	0%	0%	0%

Consumption (Actual) - Total

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential	39,383,819	42,290,456	45,777,052	52,987,941	52,545,331	55,513,150	62,190,414
Non Std A - Seasonal	365,703	344,013	348,000	301,514	347,018	380,223	368,324
Non Std A - General 1-Phase	6,078,977	7,020,635	6,843,100	7,148,021	7,040,559	7,565,753	8,120,457
Non Std A - General 3-Phase	4,707,758	4,764,790	5,421,997	6,050,805	6,736,581	6,442,439	7,104,564
Street Lighting	223,224	239,899	244,323	246,128	252,471	244,332	242,931
Std A - Residential-Road	48,652	38,680	27,664	21,801	23,091	24,905	25,282
Std A - Residential-Air	1,283,692	1,325,854	1,308,946	1,509,131	1,586,464	1,736,030	1,204,900
Std A - General-Road	762,539	777,104	727,215	739,984	793,769	848,821	763,778
Std A - General-Air	9,638,087	9,577,917	10,471,060	10,408,724	10,144,895	10,174,179	7,571,736
Std A - Grid Connected	-	-	886,816	2,761,496	2,738,020	4,032,200	9,832,428

Consumption (Actual) Variance Analysis

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential		7%	8%	16%	-1%	6%	12%
Non Std A - Seasonal		-6%	1%	-13%	15%	10%	-3%
Non Std A - General 1-Phase		15%	-3%	4%	-2%	7%	7%
Non Std A - General 3-Phase		1%	14%	12%	11%	-4%	10%
Street Lighting		7%	2%	1%	3%	-3%	-1%
Std A - Residential-Road		-20%	-28%	-21%	6%	8%	2%
Std A - Residential-Air		3%	-1%	15%	5%	9%	-31%
Std A - General-Road		2%	-6%	2%	7%	7%	-10%
Std A - General-Air		-1%	9%	-1%	-3%	0%	-26%
Std A - Grid Connected				211%	-1%	47%	144%

Consumption (Actual) - Grid

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential			2,277,623	6,585,686	6,587,110	10,189,734	30,028,695
Non Std A - Seasonal							
Non Std A - General 1-Phase			60,932	244,709	306,450	671,570	2,802,402
Non Std A - General 3-Phase			296,534	741,858	680,547	926,717	3,326,573
Street Lighting						30,291	82,920
Std A - Residential-Road							
Std A - Residential-Air							
Std A - General-Road							
Std A - General-Air							
Std A - Grid Connected			886,816	2,761,496	2,738,020	4,032,200	9,832,428

Consumption (Actual) Variance Analysis

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential				189%	0%	55%	195%
Non Std A - Seasonal							
Non Std A - General 1-Phase				302%	25%	119%	317%
Non Std A - General 3-Phase				150%	-8%	36%	259%
Street Lighting							174%
Std A - Residential-Road							
Std A - Residential-Air							
Std A - General-Road							
Std A - General-Air							
Std A - Grid Connected				211%	-1%	47%	144%

Consumption (Actual) - Off Grid

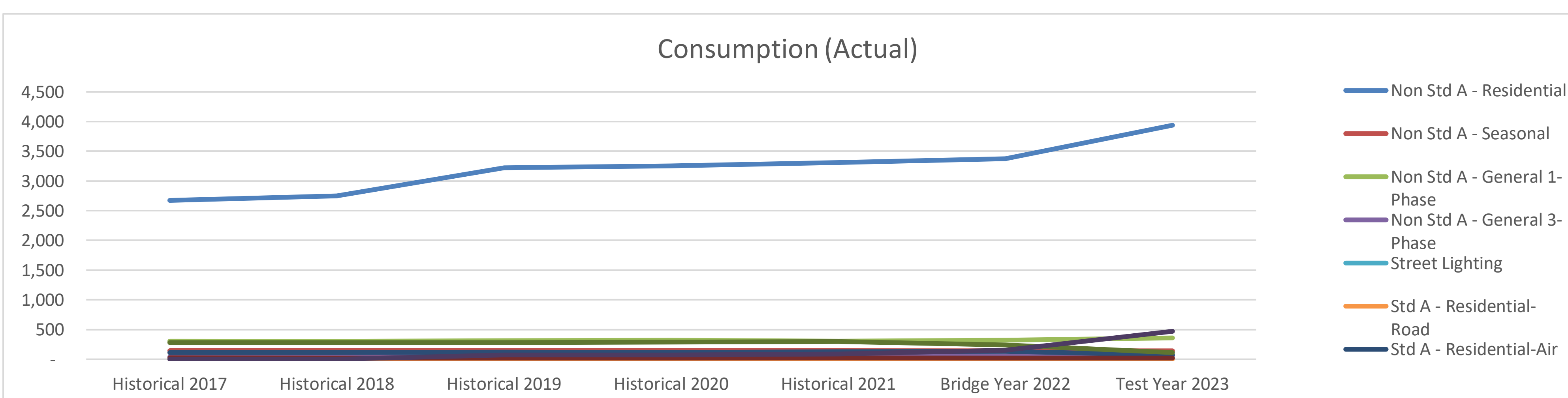
Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential	39,383,819	42,290,456	43,499,429	46,402,255	45,958,221	45,323,417	32,161,719
Non Std A - Seasonal	365,703	344,013	348,000	301,514	347,018	380,223	368,324
Non Std A - General 1-Phase	6,078,977	7,020,635	6,782,168	6,903,312	6,734,109	6,894,183	5,318,055
Non Std A - General 3-Phase	4,707,758	4,764,790	5,125,463	5,308,946	6,056,034	5,515,722	3,777,991
Street Lighting	223,224	239,899	244,323	246,128	252,471	214,041	160,011
Std A - Residential-Road	48,652	38,680	27,664	21,801	23,091	24,905	25,282
Std A - Residential-Air	1,283,692	1,325,854	1,308,946	1,509,131	1,586,464	1,736,030	1,204,900
Std A - General-Road	762,539	777,104	727,215	739,984	793,769	848,821	763,778
Std A - General-Air	9,638,087	9,577,917	10,471,060	10,408,724	10,144,895	10,174,179	7,571,736
Std A - Grid Connected	-	-	-	-	-	-	-

Consumption (Actual) Variance Analysis

Rate Class	Historical 2017	Historical 2018	Historical 2019	Historical 2020	Historical 2021	Bridge Year 2022	Test Year 2023
Non Std A - Residential		7%	3%	7%	-1%	-1%	-29%
Non Std A - Seasonal		-6%	1%	-13%	15%	10%	-3%
Non Std A - General 1-Phase		15%	-3%	2%	-2%	2%	-23%
Non Std A - General 3-Phase		1%	8%	4%	14%	-9%	-32%
Street Lighting		7%	2%	1%	3%	-15%	-25%
Std A - Residential-Road		-20%	-28%	-21%	6%	8%	2%
Std A - Residential-Air		3%	-1%	15%	5%	9%	-31%
Std A - General-Road		2%	-6%	2%	7%	7%	-10%
Std A - General-Air		-1%	9%	-1%	-3%	0%	-26%
Std A - Grid Connected							

* Remotes has updated the Rate Class to reflect its rate structure

** Remotes does not have Demand Charges or Weather normalize



Appendix 2-JA

Summary of Recoverable OM&A Expenses

	2018 Last Rebasing Year OEB Approved	2018 Last Rebasing Year Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Reporting Basis							
Operations	$ 30,612	$ 33,772	$ 36,689	$ 35,960	$ 41,176	$ 70,905	$ 109,626
Maintenance	$ 12,524	$ 11,486	$ 11,649	$ 12,294	$ 11,769	$ 11,498	$ 11,220
SubTotal	**$ 43,136**	**$ 45,258**	**$ 48,338**	**$ 48,254**	**$ 52,945**	**$ 82,403**	**$ 120,846**
%Change (year over year)		4.9%	6.8%	-0.2%	9.7%	55.6%	46.7%
%Change (Test Year vs Last Rebasing Year - Actual)							167.0%
Billing and Collecting	$ 2,151	$ 1,812	$ 1,982	$ 1,875	$ 1,409	$ 2,218	$ 2,383
Community Relations	$ 496	$ 157	$ 703	$ 459	$ 407	$ 675	$ 682
Administrative and General	$ 1,460	$ 1,801	$ 1,779	$ 1,543	$ 1,910	$ 2,518	$ 2,657
SubTotal	**$ 4,107**	**$ 3,770**	**$ 4,464**	**$ 3,877**	**$ 3,726**	**$ 5,411**	**$ 5,722**
%Change (year over year)		-8.2%	18.4%	-13.1%	-3.9%	45.2%	5.7%
%Change (Test Year vs Last Rebasing Year - Actual)							51.8%
Total	**$ 47,243**	**$ 49,028**	**$ 52,802**	**$ 52,131**	**$ 56,671**	**$ 87,814**	**$ 126,568**
%Change (year over year)		3.8%	7.7%	-1.3%	8.7%	55.0%	44.1%

	2018 Last Rebasing Year OEB Approved	2018 Last Rebasing Year Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Operations[4]	$ 30,612	$ 33,772	$ 36,689	$ 35,960	$ 41,176	$ 70,905	$ 109,626
Maintenance[5]	$ 12,524	$ 11,486	$ 11,649	$ 12,294	$ 11,769	$ 11,498	$ 11,220
Billing and Collecting[6]	$ 2,151	$ 1,812	$ 1,982	$ 1,875	$ 1,409	$ 2,218	$ 2,383
Community Relations[7]	$ 496	$ 157	$ 703	$ 459	$ 407	$ 675	$ 682
Administrative and General[8]	$ 1,460	$ 1,801	$ 1,779	$ 1,543	$ 1,910	$ 2,518	$ 2,657
Total	**$ 47,243**	**$ 49,028**	**$ 52,802**	**$ 52,131**	**$ 56,671**	**$ 87,814**	**$ 126,568**
%Change (year over year)		3.8%	7.7%	-1.3%	8.7%	55.0%	44.1%

Note:

1 Historical actuals going back to the last cost of service application are required to be entered by the applicant.
2 Recoverable OM&A that is included on these tables should be identical to the recoverable OM&A that is shown for the corresponding periods on Appendix 2-JB.
3 For unrecoverable OM&A Expenses see Section 2.4.3.7
4 USoA included in Operations: 5005, 5010, 5012, 5014, 5015, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5060, 5065, 5070, 5075, 5085, 5090, 5095, 5096
5 USoA included in Maintenance: 5305, 5310, 5315, 5320, 5325, 5330, 5335, 5340
6 USoA included in Billing and Collecting: 5105, 5110, 5112, 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5165, 5170, 5172, 5175, 5178, 5195
7 USoA included in Community Relations: 5405, 5410, 5415, 5420, 5425
8 USoA included in Administrative and General: 5505, 5510, 5515, 5520, 5605, 5610, 5615, 5620, 5625, 5630, 5635, 5640, 5645, 5646, 5647, 5650, 5655, 5660, 5665, 5670,

	Last Rebasing Year 2018 OEB Approved	Last Rebasing Year 2018 Actuals	Variance 2018 OEB Approved - 2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	Variance 2022 Bridge vs. 2021 Actuals	2023 Test Year	Variance 2023 Test vs. 2022 Bridge
Operations	**$ 30,612**	**$ 33,772**	**-$ 3,160**	**$ 36,689**	**$ 35,960**	**$ 41,176**	**$ 70,905**	**$ 29,729**	**$ 109,626**	**$ 38,721**
Maintenance	**$ 12,524**	**$ 11,486**	**$ 1,038**	**$ 11,649**	**$ 12,294**	**$ 11,769**	**$ 11,498**	**-$ 271**	**$ 11,220**	**-$ 278**
Billing and Collecting	**$ 2,151**	**$ 1,812**	**$ 339**	**$ 1,982**	**$ 1,875**	**$ 1,409**	**$ 2,218**	**$ 809**	**$ 2,383**	**$ 165**
Community Relations	**$ 496**	**$ 157**	**$ 339**	**$ 703**	**$ 459**	**$ 407**	**$ 675**	**$ 268**	**$ 682**	**$ 7**
Administrative and General	**$ 1,460**	**$ 1,801**	**-$ 341**	**$ 1,779**	**$ 1,543**	**$ 1,910**	**$ 2,518**	**$ 608**	**$ 2,657**	**$ 139**
Total OM&A Expenses	**$ 47,243**	**$ 49,028**	**-$ 1,785**	**$ 52,802**	**$ 52,131**	**$ 56,671**	**$ 87,814**	**$ 31,143**	**$ 126,568**	**$ 38,754**
Adjustments for Total non-recoverable items[3]										
Total Recoverable OM&A Expenses	**$ 47,243**	**$ 49,028**	**-$ 1,785**	**$ 52,802**	**$ 52,131**	**$ 56,671**	**$ 87,814**	**$ 31,143**	**$ 126,568**	**$ 38,754**
Variance from previous year				$ 3,774	-$ 671	$ 4,540	$ 31,143		$ 38,754	
Percent change (year over year)				0%	-1%	9%	55%		44%	
Percent Change: Test year vs. Most Current Actual									123.34%	
Simple average of % variance for all years									26.63%	
Compound Annual Growth Rate for all years										20.9%
Compound Growth Rate (2021 vs. 2018 Actuals)									4.9%	

Appendix 2-JB
Recoverable OM&A Cost Driver Table[1,3]

OM&A	Last Rebasing Year (2018 Actuals)	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Reporting Basis	USGAAP		USGAAP	USGAAP	USGAAP	USGAAP	USGAAP
Opening Balance[2]	$ 47,243	$ 47,243	$ 49,028	$ 52,802	$ 52,131	$ 56,671	$ 87,814
Other Income/ Deductions							
4330 - Costs and Expenses of Merchandising		454	102	(201)	241	(493)	(26)
Generation Expenses - Operation							
4510 - Fuel		3,505	846	(1,084)	5,311	6,720	(10,833)
4550 - Generation Expense		(170)	428	112	(251)	160	(456)
4555 - Miscellaneous Power Generation Expenses		(137)	150	(118)	(23)	317	14
Generation Expenses - Maintenance							
4610 - Maintenance of Structures		19	(137)	(126)	(52)	(267)	(173)
4635 - Maintenance of Generating and Electric Plant		(857)	25	(180)	383	(368)	(944)
Other Power Supply Expenses							
4705 - Power Purchased		14	1,449	316	(195)	22,496	50,082
4708 - Charges - WMS		0	0	0	0	0	0
Distribution Expenses - Operation							
5085 - Miscellaneous Distribution Expense		(54)	46	47	369	37	(84)
Distribution Expenses - Maintenance							
5120 - Maintenance of Poles, Towers and Fixtures		(46)	176	408	(399)	58	292
5125 - Maintenance of Overhead Conductors and Devices		42	(38)	441	(329)	48	234
5130 - Maintenance of Overhead Services		(10)	37	84	(82)	12	58
5135 - Overhead Distribution Lines and Feeders - Right of Wa		(194)	91	21	(28)	143	7
5175 - Maintenance of Meters		7	8	(3)	(16)	102	248
Billing and Collecting							
5310 - Meter Reading Expense		20	24	(8)	(49)	86	45
5315 - Customer Billing		(405)	(13)	59	(89)	298	23
5320 - Collecting		35	48	(350)	132	209	55
5335 - Bad Debt Expense		12	110	190	(459)	216	42
Community Relations							
5410 - Community Relations - Sundry		(286)	71	(18)	13	6	3
5415 - Energy Conservation		(38)	47	2	(42)	49	2
5420 - Community Safety Program		(26)	13	(12)	0	12	(6)
5425 - Misc Customer Service and Informational Expenses		12	415	(215)	(21)	201	7
Administrative and General Expenses							
5615 - General Administrative Salaries and Expenses		39	(136)	28	133	(1)	90
5625 - Administrative Expense Transferred - Credit		(111)	16	(45)	(8)	68	(5)
5655 - Regulatory Expenses		(37)	(49)	0	(6)	90	(70)
5665 - Miscellaneous General Expenses		0	0	0	0	246	0
5675 - Maintenance of General Plant		0	0	0	0	702	130
Taxes							
6105 - Taxes Other Than Income Taxes		(3)	17	(5)	1	2	2
Other Deductions							
6205 - Donations		0	28	(14)	6	(6)	17
Closing Balance[2]	$ 47,243	$ 49,028	$ 52,802	$ 52,131	$ 56,671	$ 87,814	$ 126,568

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is requied in Exhibit 4.

2 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the OEB-Approved amount. For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2018 OEB-Approved)	Last Rebasing Year (2018 Actuals)	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year	Variance (Test Year vs. 2021 Actuals)	Variance (Test Year vs. Last Rebasing Year (2018 OEB-Approved)
Reporting Basis										
Other Income/ Deductions										
4330 - Costs and Expenses of Merch	135	589	589	691	490	731	238	212	-519	77
Sub-Total	**135**	**589**	**589**	**691**	**490**	**731**	**238**	**212**	**-519**	**77**
Generation Expenses - Operation										
4510 - Fuel	25,900	29,406	29,406	30,251	29,166	34,481	41,200	30,365	-4,116	4,465
4550 - Generation Expense	3,603	3,434	3,434	3,861	3,973	3,722	3,882	3,426	-296	-177
4555 - Miscellaneous Power Generat	993	856	856	1,006	888	865	1,182	1,196	331	203
Sub-Total	**30,496**	**33,696**	**33,696**	**35,118**	**34,027**	**39,068**	**46,264**	**34,987**	**-4,081**	**4,491**
Generation Expenses - Maintenance										
4610 - Maintenance of Structures	1,410	1,431	1,431	1,294	1,168	1,116	849	676	-440	-734
4635 - Maintenance of Generating an	9,216	8,359	8,359	8,385	8,205	8,588	8,220	7,276	-1,312	-1,940
Sub-Total	**10,626**	**9,790**	**9,790**	**9,679**	**9,373**	**9,704**	**9,069**	**7,952**	**-1,752**	**-2,674**
Other Power Supply Expenses										
4705 - Power Purchased	0	14	14	1,463	1,779	1,584	24,080	74,162	72,578	74,162
4708 - Charges - WMS	0	0	0	0	0	0	0	0	0	0
Sub-Total	**0**	**14**	**14**	**1,463**	**1,779**	**1,584**	**24,080**	**74,162**	**72,578**	**74,162**
Distribution Expenses - Operation										
5085 - Miscellaneous Distribution Exp	116	62	62	108	154	524	561	477	-47	361
Sub-Total	**116**	**62**	**62**	**108**	**154**	**524**	**561**	**477**	**-47**	**361**
Distribution Expenses - Maintenance										
5120 - Maintenance of Poles, Towers	694	648	648	824	1,232	834	892	1,184	350	490
5125 - Maintenance of Overhead Cor	575	617	617	579	1,020	690	738	972	282	397
5130 - Maintenance of Overhead Ser	144	134	134	171	255	173	185	243	70	99
5135 - Overhead Distribution Lines ar	357	163	163	254	274	246	389	396	150	39
5175 - Maintenance of Meters	128	134	134	142	140	123	225	473	350	345
Sub-Total	**1,898**	**1,696**	**1,696**	**1,970**	**2,921**	**2,066**	**2,429**	**3,268**	**1,202**	**1,370**
Billing and Collecting										
5310 - Meter Reading Expense	384	403	403	427	420	369	456	501	132	117
5315 - Customer Billing	1,432	1,027	1,027	1,014	1,074	985	1,283	1,306	321	-126
5320 - Collecting	335	370	370	419	69	201	410	465	264	130
5335 - Bad Debt Expense	0	12	12	122	312	-147	69	111	258	111
Sub-Total	**2,151**	**1,812**	**1,812**	**1,982**	**1,875**	**1,408**	**2,218**	**2,383**	**975**	**232**
Community Relations										
5410 - Community Relations - Sundry	381	95	95	166	148	161	167	170	9	-211
5415 - Energy Conservation	61	23	23	70	71	29	78	80	51	19
5420 - Community Safety Program	54	27	27	40	28	27	39	34	7	-20
5425 - Misc Customer Service and In	0	12	12	427	212	190	391	398	208	398
Sub-Total	**496**	**157**	**157**	**703**	**459**	**407**	**675**	**682**	**275**	**186**
Administrative and General Expenses										
5615 - General Administrative Salarie	1,564	1,602	1,602	1,467	1,494	1,627	1,626	1,716	89	152
5625 - Administrative Expense Trans	-448	-559	-559	-544	-588	-596	-528	-533	63	-85
5655 - Regulatory Expenses	103	66	66	17	18	11	101	32	21	-71
5665 - Miscellaneous General Expen	0	0	0	0	0	0	246	246	246	246
5675 - Maintenance of General Plant	0	0	0	0	0	0	702	832	832	832
Sub-Total	**1,219**	**1,109**	**1,109**	**940**	**924**	**1,042**	**2,147**	**2,293**	**1,251**	**1,074**
Taxes										
6105 - Taxes Other Than Income Tax	55	52	52	69	64	66	68	70	4	15
Sub-Total	**55**	**52**	**52**	**69**	**64**	**66**	**68**	**70**	**4**	**15**
Other Deductions										
6205 - Donations	51	51	51	79	65	71	65	82	11	31
Sub-Total	**51**	**51**	**51**	**79**	**65**	**71**	**65**	**82**	**11**	**31**
Miscellaneous									0	0
Total	47,243	49,028	49,028	52,802	52,131	56,671	87,814	126,568	69,897	79,325

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

Appendix 2-K
Employee Costs

	Last Rebasing Year (2018 OEB Approved)	Last Rebasing Year (2018 Actuals)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Non-Management (union and non-union)*	56.30	59.70	63.00	64.00	65.70	65.60	67.40
Total	61.30	64.70	68.00	69.00	70.70	70.60	72.40
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 819,814	$ 1,053,151	$ 1,022,765	$ 1,035,782	$ 1,085,006	$ 1,112,131	$ 1,148,831
Non-Management (union and non-union)*	$ 7,327,610	$ 7,558,180	$ 7,997,650	$ 7,998,638	$ 8,755,406	$ 8,762,131	$ 9,174,236
Total	$ 8,147,424	$ 8,611,331	$ 9,020,415	$ 9,034,420	$ 9,840,412	$ 9,874,262	$ 10,323,067
Total Benefits (Current + Accrued)							
Management (including executive)	$ 175,678	$ 221,162	$ 214,781	$ 217,514	$ 227,851	$ 233,547	$ 241,255
Non-Management (union and non-union)*	$ 1,158,638	$ 1,062,865	$ 1,027,468	$ 1,021,414	$ 1,108,402	$ 1,132,787	$ 1,202,278
Total	$ 1,334,315	$ 1,284,026	$ 1,242,249	$ 1,238,928	$ 1,336,254	$ 1,366,335	$ 1,443,533
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 995,492	$ 1,274,313	$ 1,237,546	$ 1,253,297	$ 1,312,857	$ 1,345,678	$ 1,390,086
Non-Management (union and non-union)	$ 8,486,248	$ 8,621,045	$ 9,025,118	$ 9,020,052	$ 9,863,809	$ 9,894,918	$ 10,376,514
Total	$ 9,481,740	$ 9,895,358	$ 10,262,664	$ 10,273,348	$ 11,176,666	$ 11,240,597	$ 11,766,600
Total Compensation Breakdown (Capital, OM&A)							
OM&A	$ 6,698,226	$ 6,990,420	$ 7,194,070	$ 7,006,432	$ 6,806,589	$ 7,283,906	$ 7,307,058
Capital	$ 2,783,514	$ 2,904,938	$ 3,068,594	$ 3,266,916	$ 4,370,076	$ 3,956,690	$ 4,459,541
Total	$ 9,481,740	$ 9,895,358	$ 10,262,664	$ 10,273,348	$ 11,176,665	$ 11,240,596	$ 11,766,599

* 2018 OEB Approved adjusted for the new Customer Service and Community Relations officer position as per the Settlement Conference

Note:

1. If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE [1]

	Last Rebasing Year 2018 - OEB Approved	Last Rebasing Year 2018 - Actual	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Reporting Basis							
OM&A Costs							
O&M	$ 43,136	$ 45,258	$ 48,338	$ 48,254	$ 52,945	$ 82,403	$ 120,846
Admin Expenses[6]	$ 4,107	$ 3,770	$ 4,464	$ 3,877	$ 3,726	$ 5,411	$ 5,722
Total Recoverable OM&A from Appendix 2-JB [5]	$ 47,243	$ 49,028	$ 52,802	$ 52,131	$ 56,671	$ 87,814	$ 126,568
Number of Customers [2,4]	3,669	3,669	4,236	4,279	4,368	4,451	5,191
Number of FTEs [3,4]	61	65	68	69	71	71	72
Customers/FTEs	60	57	62	62	62	63	72
OM&A cost per customer							
O&M per customer	$12	$12	$11	$11	$12	$19	$23
Admin per customer	$1	$1	$1	$1	$1	$1	$1
Total OM&A per customer	$13	$13	$12	$12	$13	$20	$24
OM&A cost per FTE							
O&M per FTE	$704	$700	$711	$699	$749	$1,167	$1,669
Admin per FTE	$67	$58	$66	$56	$53	$77	$79
Total OM&A per FTE	$771	$758	$777	$756	$802	$1,244	$1,748

Notes:

1 If it has been more than four years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than four years ago, a minimum of three years of actual information is required.
2 The method of calculating the number of customers must be identified. Should correspond with data provided in Appendix 2-IB.
3 The method of calculating the number of FTEs must be identified. See also Appendix 2-K.
4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.
5 For the test year, the applicant should take into account the system O&M (line 24 of Appendix 2-AB) in developing its forecasted OM&A.
6 Includes lines 19, 20, & 21 of Appendix 2-JA

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Last Rebasing Year (2018 OEB Approved)	Last Rebasing Year (2018 Actual)	Most Current Actuals Year 2021	2022 Bridge Year	Annual % Change	2023 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=[(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
	Regulatory Costs (Ongoing)									
1	OEB Annual Assessment	5655		25	17	10	17	65.14%	18	4.41%
2	OEB Section 30 Costs (OEB-initiated)	5655		25	1	0	0	32.37%	1	5.42%
3	Expert Witness costs for regulatory matters			0	0	0	0		0	
4	Legal costs for regulatory matters			0	0	0	0		0	
5	Consultants' costs for regulatory matters			0	0	0	0		0	
6	Operating expenses associated with staff resources allocated to regulatory matters	5655		0	0	0	0		0	
7	Operating expenses associated with other resources allocated to regulatory matters [1]			0	0	0	0		0	
8	Other regulatory agency fees or assessments			0	0	0	0		0	
9	Any other costs for regulatory matters (please define)			0	0	0	0		0	
10	Intervenor costs	5655		0	0	0	1	250.24%	1	-53.18%
11	Include other items in green cells, as applicable									
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
	Regulatory Costs (One-Time)									
1	Expert Witness costs			0	0	0	0		0	
2	Legal costs			0	0	0	0		0	
3	Consultants' costs	5655		2	0	0	82		0	-100.00%
4	Incremental operating expenses associated with staff resources allocated to this application.			0	0	0	0		0	
5	Incremental operating expenses associated with other resources allocated to this application. [1]			0	0	0	0		0	
6	Intervenor costs	5655		16	39	0	0		50	
7	OEB Section 30 Costs (application-related)	5655		35	9	0	0		10	
8	Include other items in green cells, as applicable									
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
1	Sub-total - Ongoing Costs [2]		$ -	$ 50	$ 18	$ 11	$ 19	69.17%	$ 19	1.16%
2	Sub-total - One-time Costs [3]		$ -	$ 53	$ 48	$ -	$ 82		$ 60	-27.02%
3	Total		$ -	$ 103	$ 66	$ 11	$ 101	809.74%	$ 31	-69.31%

Application-Related One-Time Costs	Total
Total One-Time Costs Related to Application to be Amortized over IRM Period	$ 60
1/5 of Total One-Time Costs	$ 12

Notes:

[1] Please identify the resources involved.

[2] Sum of all ongoing costs.

[3] Sum of all one-time costs related to this application.

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

Note:

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

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

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

· ***% Allocation:***

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

Year: 2018

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HONI	HORCI	Utility Operation Se	Cost Based	$1,546	$1,546
HONI	HORCI	Supply Chain Servi	Cost Based	$76	$76
HONI	HORCI	Transfer Price Cha	Allocation Model	$327	$327

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	*HORCI*	General Counsel &	CC Allocation Mode	< 1%	$3
HOI	HORCI	President/CEO/Ch	CC Allocation Mode	< 1%	$16
HOI	HORCI	Chief Financial Offi	CC Allocation Mode	< 1%	$21
HONI	HORCI	General Counsel &	CC Allocation Mode	< 1%	$200
HONI	HORCI	Financial Services	CC Allocation Mode	< 1%	$164
HONI	HORCI	Corporate Services	CC Allocation Mode	< 1%	$284
HONI	HORCI	Telecom Services	CC Allocation Mode	< 1%	$145
HONI	HORCI	Other Services	CC Allocation Mode	< 1%	$442

Year: 2019

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HONI	HORCI	Utility Operation Se	Cost Based	$1,865	$1,865
HONI	HORCI	Supply Chain Servi	Cost Based	$76	$76
HONI	HORCI	Transfer Price Cha	Allocation Model	$327	$327

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	*HORCI*	General Counsel &	CC Allocation Mode	< 1%	$6
HOI	HORCI	President/CEO/Cha	CC Allocation Mode	< 1%	$7
HOI	HORCI	Chief Financial Offi	CC Allocation Mode	< 1%	$21
HONI	HORCI	General Counsel &	CC Allocation Mode	< 1%	$196
HONI	HORCI	Financial Services	CC Allocation Mode	< 1%	$123
HONI	HORCI	Corporate Services	CC Allocation Mode	< 1%	$265
HONI	HORCI	Telecom Services	CC Allocation Mode	< 1%	$129
HONI	HORCI	Other Services	CC Allocation Mode	< 1%	$394

Year: 2020

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HONI	HORCI	Utility Operation Se	Cost Based	$1,574	$1,574
HONI	HORCI	Supply Chain Servi	Cost Based	$76	$76
HONI	HORCI	Transfer Price Cha	Allocation Model	$327	$327

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	*HORCI*	General Counsel &	CC Allocation Mode	< 1%	$6
HOI	HORCI	President/CEO/Cha	CC Allocation Mode	< 1%	$4
HOI	HORCI	Chief Financial Offi	CC Allocation Mode	< 1%	$13
HONI	HORCI	General Counsel &	CC Allocation Mode	< 1%	$209
HONI	HORCI	Financial Services	CC Allocation Mode	< 1%	$131
HONI	HORCI	Corporate Services	CC Allocation Mode	< 1%	$266
HONI	HORCI	Telecom Services	CC Allocation Mode	< 1%	$140
HONI	HORCI	Other Services	CC Allocation Mode	< 1%	$399

Year: 2021

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HONI	HORCI	Utility Operation Se	Cost Based	$1,175	$1,175
HONI	HORCI	Supply Chain Servi	Cost Based	$76	$76
HONI	HORCI	Transfer Price Cha	Allocation Model	$327	$327

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	*HORCI*	General Counsel &	CC Allocation Mod	< 2%	$28
HOI	HORCI	President/CEO/Cha	CC Allocation Mod	< 1%	$26
HOI	HORCI	Chief Financial Offi	CC Allocation Mod	< 1%	$2
HONI	HORCI	General Counsel &	CC Allocation Mod	< 1%	$303
HONI	HORCI	Financial Services	CC Allocation Mod	< 1%	$143
HONI	HORCI	Corporate Services	CC Allocation Mod	< 1%	$298
HONI	HORCI	Telecom Services	CC Allocation Mod	< 1%	$132
HONI	HORCI	Other Services	CC Allocation Mod	< 1%	$370

Year: 2022

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HONI	HORCI	Utility Operation Se	Cost Based	$1,284	$1,284
HONI	HORCI	Supply Chain Servi	Cost Based	$76	$76
HONI	HORCI	Transfer Price Cha	Allocation Model	$327	$327

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	*HORCI*	General Counsel &	CC Allocation Mod	< 5%	$28
HOI	HORCI	President/CEO/Cha	CC Allocation Mod	< 1%	$26
HOI	HORCI	Chief Financial Offi	CC Allocation Mod	< 1%	$1
HONI	HORCI	General Counsel &	CC Allocation Mod	< 1%	$315
HONI	HORCI	Financial Services	CC Allocation Mod	< 1%	$149
HONI	HORCI	Corporate Services	CC Allocation Mod	< 1%	$310
HONI	HORCI	Telecom Services	CC Allocation Mod	< 1%	$131
HONI	HORCI	Other Services	CC Allocation Mod	< 1%	$340

Year: 2023

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HONI	HORCI	Utility Operation Se	Cost Based	$1,314	$1,314
HONI	HORCI	Supply Chain Servi	Cost Based	$76	$76
HONI	HORCI	Transfer Price Cha	Allocation Model	$402	$402

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOI	*HORCI*	General Counsel &	CC Allocation Mode	< 5%	$29
HOI	HORCI	President/CEO/Cha	CC Allocation Mode	< 1%	$27
HOI	HORCI	Chief Financial Offi	CC Allocation Mode	< 1%	$2
HONI	HORCI	General Counsel &	CC Allocation Mode	< 1%	$299
HONI	HORCI	Financial Services	CC Allocation Mode	< 1%	$153
HONI	HORCI	Corporate Services	CC Allocation Mode	< 1%	$340
HONI	HORCI	Telecom Services	CC Allocation Mode	< 1%	$133
HONI	HORCI	Other Services	CC Allocation Mode	< 1%	$331

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last OEB-approved year and the test year.

Test Year: 2023

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	96.00%		$53,969	4.63%	$2,499
2	Short-term Debt	4.00%	(1)	$2,249	1.17%	$26
3	**Total Debt**	100.0%		$56,218	4.49%	$2,525
	Equity					
4	Common Equity	0.00%		$ -	0.00%	$ -
5	Preferred Shares			$ -		$ -
6	**Total Equity**	0.0%		$ -	0.00%	$ -
7	**Total**	100.0%		$56,218	4.49%	$2,525

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

Last OEB-approved year: 2018

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	96.00%		$43,698	4.63%	$2,023
2	Short-term Debt	4.00%	(1)	$1,821	2.29%	$42
3	**Total Debt**	100.0%		$45,519	4.54%	$2,065
	Equity					
4	Common Equity	0.00%		$ -	0.00%	$ -
5	Preferred Shares			$ -		$ -
6	**Total Equity**	0.0%		$ -	0.00%	$ -
7	**Total**	100.0%		$45,519	4.54%	$2,065

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

Appendix 2-OB
Debt Instruments

Notes

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009, or with
3 Add more lines above row 12 if necessary.

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	$23M note maturing May 20, 2036	Hydro One Inc.	Third-Party	Fixed Rate	19-May-05	31	$ 23,000,000	0.056	$1,288,000.00	
2	$10M note maturing June 6, 2044	Hydro One Inc.	Third-Party	Fixed Rate	6-Jun-14	30	$ 10,000,000	0.0421	$ 421,000.00	
3	$10M note maturing Feb 24, 2026	Hydro One Inc.	Third-Party	Fixed Rate	24-Feb-16	10	$ 10,000,000	0.0282	$ 282,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 43,000,000	4.63%	$1,991,000.00	

Year 2019

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	$23M note maturing May 20, 2036	Hydro One Inc.	Third-Party	Fixed Rate	19-May-05	31	$ 23,000,000	0.056	$1,288,000.00	
2	$10M note maturing June 6, 2044	Hydro One Inc.	Third-Party	Fixed Rate	6-Jun-14	30	$ 10,000,000	0.0421	$ 421,000.00	
3	$10M note maturing Feb 24, 2026	Hydro One Inc.	Third-Party	Fixed Rate	24-Feb-16	10	$ 10,000,000	0.0282	$ 282,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 43,000,000	4.63%	$1,991,000.00	

Year 2020

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	$23M note maturing May 20, 2036	Hydro One Inc.	Third-Party	Fixed Rate	19-May-05	31	$ 23,000,000	0.056	$1,288,000.00	
2	$10M note maturing June 6, 2044	Hydro One Inc.	Third-Party	Fixed Rate	6-Jun-14	30	$ 10,000,000	0.0421	$ 421,000.00	
3	$10M note maturing Feb 24, 2026	Hydro One Inc.	Third-Party	Fixed Rate	24-Feb-16	10	$ 10,000,000	0.0282	$ 282,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 43,000,000	4.63%	$1,991,000.00	

Year 2021

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	$23M note maturing May 20, 2036	Hydro One Inc.	Third-Party	Fixed Rate	19-May-05	31	$ 23,000,000	0.056	$1,288,000.00	
2	$10M note maturing June 6, 2044	Hydro One Inc.	Third-Party	Fixed Rate	6-Jun-14	30	$ 10,000,000	0.0421	$ 421,000.00	
3	$10M note maturing Feb 24, 2026	Hydro One Inc.	Third-Party	Fixed Rate	24-Feb-16	10	$ 10,000,000	0.0282	$ 282,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 43,000,000	4.63%	$1,991,000.00	

Year 2022

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	$23M note maturing May 20, 2036	Hydro One Inc.	Third-Party	Fixed Rate	19-May-05	31	$ 23,000,000	0.056	$1,288,000.00	
2	$10M note maturing June 6, 2044	Hydro One Inc.	Third-Party	Fixed Rate	6-Jun-14	30	$ 10,000,000	0.0421	$ 421,000.00	
3	$10M note maturing Feb 24, 2026	Hydro One Inc.	Third-Party	Fixed Rate	24-Feb-16	10	$ 10,000,000	0.0282	$ 282,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 43,000,000	4.63%	$1,991,000.00	

Year 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	$23M note maturing May 20, 2036	Hydro One Inc.	Third-Party	Fixed Rate	19-May-05	31	$ 23,000,000	0.056	$1,288,000.00	
2	$10M note maturing June 6, 2044	Hydro One Inc.	Third-Party	Fixed Rate	6-Jun-14	30	$ 10,000,000	0.0421	$ 421,000.00	
3	$10M note maturing Feb 24, 2026	Hydro One Inc.	Third-Party	Fixed Rate	24-Feb-16	10	$ 10,000,000	0.0282	$ 282,000.00	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 43,000,000	4.63%	$1,991,000.00	

Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2017	2018	2019	2020	2021	
	Losses Within Distributor's System*						
A(1)	"Wholesale" kWh delivered to distributor (higher value)				11,394,580	11,890,609	11,642,595
A(2)	"Wholesale" kWh delivered to distributor (lower value)				11,019,903	11,499,622	11,259,763
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	-	-	-	11,019,903	11,499,622	11,259,763
D	"Retail" kWh delivered by distributor				10,333,749	10,312,127	10,322,938
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	-	-	-	10,333,749	10,312,127	10,322,938
G	Loss Factor in Distributor's system = **C / F**				1.0664	1.1152	1.0908
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor				1.0340	1.0340	1.0340
	Total Losses						
I	Total Loss Factor = **G x H**				1.1027	1.1531	1.1278

* Remotes is currently operating similar to an embedded distributor on a modified transmission connection agreement with Watay and Hydro One Networks for the community of Pikangikum. The cost of power is currently settled directly with Hydro One Networks. The losses incurred on both the transmission and distribution systems are embedded in the cost of power assumption, which are recovered through Rate Revenue and a larger portion to RRRP. The modified transmission connection agreement is expected to end August 2022 when Pikangikum re-connects to the new Watay line. Future cost of power

Notes:

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**). This value should not include supply facility losses. However, the total loss factor on the tariff of rate and charges and applied to customers consumption should include the supply facility loss factor.

D kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

E Metered consumption of Large Use customers.

G and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H Actual Supply Facility Loss Factor as calculated by dividing A(1) by A(2).

SUMMARY OF REMOTES BUSINESS

1.0 INTRODUCTION

Remotes is an integrated generation and distribution company licensed to generate and distribute electricity within 21 isolated communities in northern Ontario and is distributor to 1 community connected to the province's electricity grid (EG-2003-0138 and ED-2003-0037). A list of the communities served, and a map of Remotes' distribution service territory can be found in DSP Section 5.2.1. Remotes is 100% debt-financed and operates as a break-even business.

Remotes is driven by its corporate vision, mission and business values. Together, they provide the basis to deliver on targeted performance objectives. The business plan underpinning this Application is filed as Exhibit A, Tab 3, Schedule 1, Attachment 1.

1.1 CORPORATE VISION

"We will be a leading remote community generation and distribution utility measured on performance in safety, environment and customer loyalty".

1.2 CORPORATE MISSION

"We are a remote community electrical generation and distribution company focused on customer satisfaction and on using management systems to achieve operational excellence."

1.3 CORPORATE VALUES

We value:

- A safe work environment
- Customers and community relationships
- Environmental sustainability
- Consistent, fair, treatment of customers and staff

- Financial responsibility and accountability
- Business integrity
- Employee engagement
- Innovation and continuous improvement

2.0 REMOTES' BUSINESS ENVIRONMENT

Remotes functions in a unique environment. Extremely low customer densities, a harsh climate, logistical challenges related to transportation, along with the absence of an integrated transmission system and complex funding arrangements with third parties, set Remotes apart from other Ontario electricity distributors. This unique operating environment has a profound impact on operations and costs throughout Remotes' service area.

The communities served by Remotes are isolated and are scattered across the far north of the Province. Fourteen communities are not accessible by year-round road and can be accessed only by aircraft, winter road or, in the case of two communities, also by barge. The size and isolation of Remotes' service territory also means that the transportation and accommodation of staff, fuel, and equipment is a key driver of Remotes' costs. The use and viability of winter roads to reach these communities is a major cost variable within Remotes' operations. If a winter road cannot be built in a given year, fuel costs, equipment costs and overall maintenance costs increase.

Remotes inherited Ontario Hydro's obligations to provide electricity to off-grid communities, which were originally negotiated with the federal and provincial governments. Under these arrangements, the federal and provincial governments funded the original capital installation of facilities. In First Nation communities, the arrangements with the federal government, through Indigenous Services Canada (ISC), remain in place. These Agreements specify that Remotes is responsible for funding ongoing operation and maintenance of the system and that ISC is responsible for funding capital related to system expansions and capital upgrades.

During the 1990s, ISC devolved its responsibility for community infrastructure to First Nation communities. ISC now transfers funding directly to First Nations, who are responsible for administering approximately 85 percent of the Department's program funds. As a result of these funding arrangements, the process for capital upgrades is complex and not completely within Remotes' control.

In 2016, the provincial government designated Wataynikaneyap Power Limited Partnership (Watay) to construct a Transmission line to connect 16 remote First Nation communities to the grid of which 10 are currently served by Remotes and 6 are unregulated Independent Power Authorities (IPAs). In the spring of 2019, the OEB approved Watay's $1.3 billion Leave to Construct. As part of the Transmission grid connection project, all IPA communities have requested distribution services from Remotes. Construction is underway, with the plan to connect communities starting in 2022, with all communities connected by the end of 2024. The proposed cost recovery framework will charge the cost of the Transmission facilities to Remotes as a direct expense, which will be recovered through the RRRP. Watay has projected the cost to Remotes will grow to be approximately $104M per year over the Plan period. The Watay transmission cost will be only partially offset by fuel and maintenance savings.

Remotes continues to be focused on growth and operational excellence over the next five years. Remotes will continue to concentrate on providing safe, reliable and affordable electricity to customers through diesel generation and distribution services. Remotes will grow the business by acquiring new communities through the Watay grid development project. The development and implementation of a back-up generation service to new and existing communities will be a shift for operations and unique for a utility in the province. Over the Plan period, Remotes will see increased complexity in the business as the service territory grows and transitions from an embedded to Transmission connected distributor while continuing to offer off-grid generation and distribution services.

3.0 DISTRIBUTION

Remotes operates 20 isolated distribution systems to serve the 22 communities. Within each system, Remotes is responsible for transformation, voltage regulation, delivery and metering of power. Because the communities are far from each other, the distribution systems are isolated, distinct and stand-alone. These distribution systems operate at distribution voltages ranging from 4.16 kV to 27.6 kV.

The fixed distribution assets in service include approximately 272 kilometers of line and 1,174 transformers distributed throughout the system, which are used for voltage transformation. Billing meters are used to measure energy consumption at customer supply points.

4.0 GENERATION

Due to the lack of grid connection, Remotes is a generator of electricity to meet its obligations under section 29 of the *Electricity Act*. Diesel generation is currently the prime source of electricity within the communities. Remotes operates two run-of-the-river mini-hydroelectric generating facilities. The feasibility of using further renewable technologies is continually examined as new technologies evolve, but diesel is currently the most reliable and cost-effective technology.

There are presently 57 diesel generators in service, ranging in size from 60kW to 1500kW. Most stations have three generators, sized to meet community load at different times of the day. Automated operation ensures that the generation units are run to maximize fuel efficiency by matching the generator size to the community load. Currently, Remotes handles over 20 million litres of diesel fuel each year.

5.0 ENVIRONMENTAL MANAGEMENT SYSTEM

Remotes developed an Environmental Management System (EMS) in 1999 to help address a history of spills and to improve environmental performance. In the course of developing and implementing the EMS, Remotes has transformed itself into an environmental leader, recognized provincially and nationally for its environmental record. In 2001, Remotes was awarded the Canadian Council of Ministers of the Environment National Pollution Prevention award for small business in Canada. In 2002, Remotes achieved ISO 14001 registration of its EMS. In 2022, Remotes is celebrating its 20th year historic milestone, confirming its commitment to this world-class environmental management system.

Remotes has achieved operating efficiency improvements through installation of automated Programmable Logic Controller (PLC) controls, Supervisory Control and Data Acquisition (SCADA) systems, upgraded engines and redesigned generating and fuel-handling software to support its PLC programs, all of which have resulted in improved efficiency, reduced use of diesel fuel and lower atmospheric emissions.

In 2003, Remotes developed and adopted an Emission Reduction Strategy and submitted an application and Action Plan for Reducing Greenhouse Gases to the Environment Canada Voluntary Challenge Registry (now known as Clean Start). Remotes continues to report, monitor and reduce its emissions.

6.0 GOVERNMENT REGULATION AND REMOTE COMMUNITY RATES

Remotes serves approximately 4,200 customers. Most customers within Remotes pay rates below the cost of service. Historically, rates for these Residential and General Service customers have been financially supported through a cross-subsidy from government customers within Remotes who historically have paid rates above cost (Standard A Rates), also through ISC capital contributions and Rural or Remote Rate Protection (RRRP). RRRP funding is currently set at $35,223k per year. This amount is funded through a $0.0005 per kWh charge[1] to all grid-connected customers in Ontario that is set by the Ontario Energy Board to fund rate protection in rural and remote areas of the province.

[1] Supplementary Decision and Order EB-2021-0300

Hydro One Remote Communities Inc.

2022-27 Business Plan

October 22, 2021

Hydro One Remote Communities Inc.

Hydro One Remote Communities (Remotes) generates and distributes electricity to customers in 21 off-grid communities and is also the distributor to one community connected to the province's electricity grid. It is 100% debt financed and is operated as a break-even company, with net income of zero in all years over the Plan period, and with adjustments to the system wide Rural or Remote Electricity Rate Protection (RRRP) charge to recover variances in net income each year.

Seventeen of the communities currently served by Remotes are First Nation communities, isolated and scattered across Ontario's far north. These communities face many challenges and are economically disadvantaged. The capital required to meet community load growth is funded by the federal government in all off-grid communities. Consequently, work is planned and executed in close collaboration with the First Nations communities, their Tribal Councils and Indigenous Services Canada. We engage First Nations in its business as employees, contractors, local operators[1] and meter readers. Many of our suppliers are First Nation enterprises or have a First Nation component to their business. Due to government regulation, Remotes' customer rates are not set to the cost of service model. Residential customers pay rates far below the cost of service. Customer rates have historically increased by the rate of inflation each year.

Strategic Goals

Consistent with Hydro One's overall goals and with our vision and mission, Remotes' 2022 business plan is designed to meet the following objectives:

- Create an injury-free workplace and protect the safety of the public
- Supply safe, reliable, and affordable electricity to our customers
- Offer an exceptional customer experience
- Build strong, respectful relationships with community leaders
- Improve the safety, reliability and efficiency of distribution and generation systems
- Build a culture of actively engaged employees, with the skills and ability to respond to our customers' needs
- Protect and sustain the environment for future generations

Business Context

In 2016, the provincial government designated Wataynikaneyap Power Limited Partnership (Watay) to construct a Transmission (Tx) line to connect 16 remote First Nation communities to the grid of which 10 are currently served by Remotes and 6 are unregulated Independent Power Authorities (IPAs).

In the spring of 2019, the OEB approved Watay's $1.3 billion Leave to Construct. As part of the Tx connection project, all IPA communities have requested distribution services from Remotes. Watay has selected Valard Construction as the engineering-procurement-construction (EPC) provider with the plan to connect communities starting in 2022, with all communities connected by the end of 2024. The proposed cost recovery framework will charge the cost of the Tx facilities to Remotes as a direct expense, which will be recovered through the RRRP. Watay has projected the cost to Remotes will grow to be approximately $104M per year over the Plan period. These Tx tariffs will be only partially offset by fuel and maintenance savings.

Remotes continues to be focused on growth and operational excellence over the next five years. Remotes will continue to concentrate on providing safe, reliable and affordable electricity to customers through diesel generation and distribution services. Remotes will grow the business by acquiring new communities through the Wataу grid development project. The development and implementation of a back-up generation service to new and existing communities will be a shift for operations and unique for a utility

---

[1] *Operators: Employees of the First Nation Band Council who perform daily operations and minor maintenance in Remotes' generating stations.*

in the province. Over the Plan period, Remotes will see increased complexity in the business as the service territory grows and transitions from an embedded to Tx connected distributor while continuing to offer off-grid generation and distribution services.

Major Initiatives

Remotes expects to integrate 6 new unregulated distribution systems into its service territory over the next three years. Significant effort from Watay and Remotes will be required to ensure that community readiness and a smooth transition to regulated service occurs. Proposed Tx development by Watay Power will drive major changes in Remotes' business, resulting in a 40% increase in customers, new settlement and financial processes, increased interaction with government, First Nations, Tribal Councils and industry regulators. Changes to operations include: on-grid operating and connection agreements; coordination with other distributors and transmitters; as well as, new processes and assets.

All of the communities connecting to the grid through the Watay transmission system are currently supplied with locally generated electricity, primarily from diesel fuel. In general, supply from local generation is more reliable than supply transmitted over long radial lines. Consequently, Remotes continues to work with both the federal and provincial governments, the local communities and their project partners on providing reliable back-up power in communities post connection.

Remotes will continue to serve 12 off-grid communities once the Watay project is complete. Remotes will continue to manage its business based on the principles of operational excellence and continuous improvement in all aspects of operations. Safe, reliable and affordable electricity are valued by Hydro One customers and will underpin all decisions and investments.

Significant Assumptions and Interdependencies

- The Watay project will be fully in service by 2024, with two communities connecting in 2022, nine in 2023, and five in 2024.
- The Watay project including the proposed cost recovery framework is approved by the OEB as filed.
- Customer rates are expected to increase by inflation each year. The RRRP changes each year to reflect forecasted costs.
- Standard "A" rates will be retained throughout the plan period, but lower Standard "A" rates will apply when communities are connected to the grid.
- Rural and Remote Rate Protection will continue for the plan period in its current form. The current Regulation does not cap the amount of rate protection available to remote customers.
- RRRP variance account will be retained and cleared through cost of service proceedings.
- Federal capital funding will be available for necessary shorter-term upgrade projects through the plan period.
- Back-up power will be initiated within the plan period in most newly grid connected communities.

Risks

Similar to prior years, three of our top risks remain: safety, transmission connection uncertainty, and Indigenous relationship uncertainty. Employee retention, succession and redundancy surfaced as a top risk in 2021. Remotes has on-going plans, programs and initiatives to actively manage and address these risks.

Safety

The risk of an employee or operator injury or fatality is a constant concern and is always a top priority. Controls in place include a long established and strong performing Environment, Health and Safety Management System, controls and process in place for all work activities, and safety moments at every meeting to keep safety top of mind. We continue to face the risk of a geographically dispersed service territory with both employees and operators working largely unsupervised. Training, procedures, compliance reviews, improvements to the sites, supervisory workplace inspections and support are partial controls for this risk.

Transmission Connection Uncertainty

By 2022, Remotes expects to be a transmission connected utility, which will mean that a number of new requirements will apply and new processes will need to be developed and implemented. The hybrid model created by serving on and off-grid communities will introduce a new level of complexity to Remotes which will necessitate a certain fluidity to the Plan as challenges are more comprehensively understood and mitigated. Challenges are expected in the collection and integration of IPA customer information to Remotes' systems, settlements and wholesale metering activities, as well as coordination and communications with a newly formed transmitter that has no operating experience and minimal operational resources deployed. To manage these risks, Remotes is working with Watay, IESO and Networks to develop a broader base understanding of requirements. Remotes will also leverage its experience gained in the Pikangikum transition. Watay project timelines have been negatively affected as a result of COVID and other construction challenges which introduce a level of uncertainty regarding community connection time frames and associated work.

Indigenous Relationship Uncertainty

Remotes operates in a unique, complex and often politically charged environment. Significant economic and social issues are facing the communities we serve. It is paramount that Remotes be viewed as a collaborative and trusted partner and wholeheartedly dedicated to exceptional customer and community experience in order to execute our growth strategy as the communities we serve choose their service provider. As well, all First Nations that we currently serve adhere to a two-year election cycle which introduces challenges to long-term relationship building with community leadership. Remotes will continue to develop customer and community programs to facilitate communication, develop understanding, meet customers' expectations, build capacity and promote Indigenous culture in order to foster strong and respectful relationships.

Employee Retention, Succession & Redundancy

Remotes faces multiple challenges: retaining a young workforce with highly marketable skills who may be reluctant to spend consistent time away from their families in the far north, the potential retirement of experienced staff and developing or finding supervisors and managers capable of wearing multiple hats. To manage these challenges, we actively seek to create an engaging work environment by investing in staff and creating development opportunities. There is a substantial focus on training for employees to enhance skills and learn new technologies. We have documented critical activities to assist new employees in taking over tasks and continue to develop and promote internal growth opportunities as well as providing rotations to apprentices and others to broaden the pool of Networks'employees with exposure and knowledge of Remotes. Additionally, we developed an employee-centered wellness program that responds to employees' suggestions on how to reduce stress and improve health within the workplace. Currently, over 25% of our employees are eligible for retirement, growing to 40% over the plan period. Succession planning for a small business is challenging as redundancy is minimal and many key roles are unique to Remotes thus making the attraction and development of new employees and apprentices critical to our long-term success.

Cost of Service

Remotes' business model and its existence relies heavily on continuing government and OEB support. We are fully expecting that Rural and Remote Rate Protection (RRRP) will continue for the plan period in its current form and that the RRRP variance account will be retained and cleared through cost of service proceedings. This is further supported by the government utilizing Remotes' unique ability to access RRRP to fund Watay transmission operating costs.

Since the 2018 Cost of Service, Remotes has generally followed both the OMA and Capital approved programs and has also successfully managed third party Customer Capital funding investments. For 2022, we will begin to see the impacts of the Watay grid project on RRRP.

The variance account is expected to be cleared in the next COS filing in 2023, which is expected to be $17.1M in 2022. This amount includes $4.5M that was not cleared during the 2018 COS due to the OEB's view on the treatment of pension costs. Beyond 2023, we will require increased RRRP funding to fully support Watay transmission costs.

Financial Analysis

Over the plan period, energy revenue remains flat as more customers are served, but are offset by the reduction in higher Standard "A" rates once grid connected. OMA also remains fairly flat as reduction in generation spending are offset by climbing distribution costs. Fuel costs are expected to drop, as usage dwindles offset in a similar fashion by cost of power increases as communities become grid connected. Capital programs, mainly driven by generation projects remain steady for the next three years, but drop off in 2025, as generation capital upgrades and replacement needs diminish.

The introduction of Watay transmission costs, beginning in 2022 and growing to $104M by the end of the planning period, significantly alter the financial structure and cost effectiveness of Remotes. The total cost per kWh, nearly doubles over the plan period as the Watay Tx costs are spread over our limited customer usage.

Financial Summary

Summary								
	Actual	Forecast	Budget			Outlook		
$K	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Revenue - Customer/Other	23,188	24,417	24,090	24,652	24,179	24,215	24,737	25,260
Subsidy	35,223	35,223	35,223	38,554	38,554	38,554	38,554	38,554
OM&A	(21,185)	(22,373)	(22,533)	(22,050)	(22,246)	(23,314)	(23,443)	(22,925)
Watay Transmission Costs	0	0	(21,285)	(66,000)	(103,695)	(103,695)	(103,695)	(103,695)
Cost of Power	(1,779)	(1,792)	(2,795)	(8,162)	(14,106)	(15,954)	(16,351)	(16,898)
Fuel	(29,166)	(33,699)	(32,461)	(23,356)	(12,720)	(10,648)	(10,812)	(10,971)
Other	(5,790)	(6,550)	(8,237)	(8,015)	(8,978)	(9,057)	(7,543)	(9,711)
Shortfall - RRRP	**491**	**(4,774)**	**(27,998)**	**(64,377)**	**(99,012)**	**(99,899)**	**(98,553)**	**(100,386)**
Capital Expenditures (gross)	13,150	13,361	15,592	15,723	13,050	5,595	5,837	5,054
Capital Expenditures (net)	3,750	5,544	8,789	10,591	7,648	3,332	3,532	2,702
Total Energy Revenue/kWh	0.27	0.28	0.28	0.24	0.21	0.20	0.21	0.21
Total Cost/kWh	0.67	0.75	0.99	1.21	1.37	1.35	1.33	1.34

Summary of Investments – OMA

OMA is generally consistent year over year with some increase in distribution work, offset by generation reductions as both new and old communities become grid connected.

Summary of Remotes OM&A Plan								
	Actual	Forecast	Budget			Outlook		
$K	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Common	717	1,667	1,459	1,541	1,700	1,754	1,785	1,886
Distribution Sustainment	3,634	4,140	3,910	4,759	5,000	5,491	6,142	5,195
Distribution Customer	1,524	1,276	1,449	1,535	1,548	1,565	1,592	1,616
Environment	888	1,108	1,182	1,196	1,216	1,238	1,256	1,278
Generation Sustainment	12,268	11,734	12,208	10,635	10,267	10,329	9,751	9,969
Generation Development	758	575	743	743	733	733	733	733
Other	1,396	1,873	1,582	1,641	1,782	2,204	2,184	2,248
OM&A	**21,185**	**22,373**	**22,533**	**22,050**	**22,246**	**23,314**	**23,443**	**22,925**

Common includes regulatory activities, community relations, customer outreach and program delivery, and the civil maintenance program for auxiliary buildings.

Distribution Sustainment includes on-going distribution sustainment activities such as forestry and maintenance, as well as trouble calls, generally increasing over time as our service territory expands. Maintenance on distribution assets is intended to ensure that the overall reliability of the distribution systems is maintained and improved, customer commitments are met, and all legislative and regulatory requirements are met.

Distribution Customer includes billing and customer account service generally increasing as the customer counts grows.

Environment includes health, safety and environmental support activities such as safety meeting material preparation, compliance assistance, waste management, training as well Environment, Health and Safety Management System (EHSMS) implementation, monitoring and audits necessary to ensure compliance, promote continuous improvement and maintain ISO 14001 registration.

Generation Sustainment includes engine and alternator maintenance, auxiliary and tank farm maintenance, in which the costs are slowly reducing over time as communities become grid connected offset by back-up power sustainment activities.

- Generator maintenance includes planned and unplanned costs. Planned maintenance of diesel generating units prevents premature equipment and system failures and contributes to service reliability. It includes all work performed on the diesel engine and associated alternator in accordance with standard maintenance procedures as prescribed by the original equipment manufacturer. Unplanned maintenance includes maintenance and repair of diesel generating units in response to trouble reports and equipment/component failures.
- Auxiliary maintenance includes, the main breaker cabinet, the station PLC, secondary heating, primary cooling, ventilation, pump controls, overhead crane inspections, station air compressors, DC batteries, station service electrical equipment and fire protection systems and all fuel system equipment and controls within the station.
- Tank farm maintenance includes regular inspections of all bulk fuel storage tanks, transfer pumps, control circuitry, piping and valves in the tank farm and the fuel delivery kiosk and metering units. This work helps prevent premature failures and ensures the tank farm remains in working condition throughout its asset life.

Generation Development includes on-going safety, environmental improvements as well as engineering investigation of contemporary operational issues and concerns. These programs decrease over time as more communities are grid connected.

Other includes mainly Corporate Functions & Services (CF&S) fees for support services received from other Hydro One entities.

2022 OMA Overview

The OMA program is generally consistent year over year and is consistent with the 2018 COS. There are no material changes in the 2022 budget as grid connection gains momentum in future years.

Summary of Investments – Capital

Total Capital has continued shorter term investment in core generation capital replacement and upgrades, transitioning into wholesale metering and back-up activities. Significant capital reductions are noted after grid connection starting 2025.

Summary of Remotes Capital Plan								
	Actual	Forecast	Budget			Outlook		
$K	2020	2021	2022	2023	2024	2025	2026	2027
Distribution Sustainment	177	532	349	548	601	400	406	411
Distribution Development	1,048	627	2,026	4,328	2,979	687	702	714
Distribution Customer	1,128	1,742	1,290	1,438	1,621	1,709	1,741	1,772
Facilities	11	901	887	1,952	437	447	454	462
Generation Sustainment	2,870	3,575	6,187	4,337	4,159	514	574	664
Generation Development	481	1,152	120	901	1,018	1,708	1,830	901
Generation Customer	7,298	4,702	4,603	2,089	2,105	0	0	0
Minor Fixed Assets	138	130	130	130	130	130	130	130
Total Capital, Gross	**13,151**	**13,361**	**15,592**	**15,723**	**13,050**	**5,595**	**5,837**	**5,054**
Contributed Capital, Removals	(9,401)	(7,817)	(6,803)	(5,132)	(5,402)	(2,263)	(2,305)	(2,352)
Total Capital, Net	**3,750**	**5,544**	**8,789**	**10,591**	**7,648**	**3,332**	**3,532**	**2,702**

Distribution Sustainment includes defective meter replacements, damage claims, service cancellations and small external demand requests. There is moderate program spending similar to existing, with occasional one-time variances for the addition of new communities and customer metering implementation.

Distribution Development involve replacing and/or refurbishing system assets to extend the service life of the assets and thereby maintain the ability of remotes' distribution system to provide customers with reliable electricity services at reasonable rate. This program has significant investments (ranging from $1.4M to $2.3M annually) in 2022 to 2024 related to wholesale metering cluster construction with the addition of new communities.

Distribution Customer includes new customer connections, service upgrades and fixed price layouts, all of which are initiated by customers and are all 100% recoverable from customers. This program has increasing new connection customer activity from the addition of new communities, expected government housing investments and school projects.

Facilities relates to staff housing improvements, TWE garages, storage buildings and other various civil projects with some investments made to the newly acquired communities.

Generation Sustainment are modifications to generation assets to ensure that the system continues to meet Remotes' operational objectives, while addressing anticipated future customer electricity requirements and includes engine replacements and overhauls, renewable energy technology, diesel plant civil improvements and back-up generation. This program has on-going generation investments including overhauls and replacements of gensets. 2022 and 2023 include Big Trout Lake A replacement, 2022 includes Deer Lake C unit replacement, 2024 includes Lansdowne C unit replacement and 2023 and 2024 includes Armstrong A, B and C units all of which are nearing end of life. Back-up power design for IPA sites added to the 2021-2024 period. The communities of Lansdowne and Armstrong are not connecting to the grid. Generation sustainment activities drop off significantly in 2025 as diesel energy production falls.

Generation Development includes SCADA upgrades and enhancements, leak detection and fuel system compliance work and improvements in the shorter term but drops off in future years.

Generation Customer has ISC fully funded upgrades including Webequie in 2022, Gull Bay Upgrade (Phase 3 execution) in 2022 to 2023, and Lansdowne in 2023 to 2024. All three communities noted are not part of the broader Watay project, so on-going diesel investments are required.

Minor Fixed Assets includes on-going tools and equipment requirements to support business activities.

2022 Capital Overview

We are starting the wholesale metering cluster construction work in 2022 relating to the Watay project. Customer connections are expected to continue to grow. Generation investments are being made to maintain reliability in leading up to grid-connection and customer driven upgrades are necessary in off-grid communities to allow for growth and ensure reliable service.

Included in the 2022 Capital Budget are the following capital projects that are greater than $500K:

2022 Budget - Capital Items (Gross) > $500K	
$K	**Budget 2022**
Distribution Development	
Distribution System Improvements	601
Wholesale Metering Construction	1,425
Distribution Customer	
New Cust Connections & Service Upgrades	997
Facilities	
Beaverhall Office Expansion	501
Generation Sustainment	
Engine Replacements	
Big Trout A Unit - Genset Replacement	4,381
Deer Lake C (Detroit)	1,102
Generation Customer	
Gull Bay Upgrade - Phase 3 Execution	1,002
Webequie 1.5 MW G1	3,551

Refer to Appendix A for the budgeted financial statements.

Staff Count

Staff Count	Actual 2020	Forecast 2021	Budget 2022	Outlook 2023	2024	2025	2026	2027
MCP	5	5	5	5	5	5	5	5
SOC	14	15	16	16	16	16	16	16
PWU - Main Trade	18	18	21	21	21	21	21	21
PWU - Weekly Salaried	18	18	19	21	22	22	22	22
Total Regular Staff	**55**	**56**	**61**	**63**	**64**	**64**	**64**	**64**

Remotes' work is performed by regular and hiring hall staff, services purchased from Hydro One Networks (including lines, forestry, health and safety, environment, engineering), contracts with external firms (engineering, environmental services) augmented by contracts with local communities for station operators, meter readers, as well as, casual resources related to land assessment and remediation, construction and CDM projects.

Full-time regular staff perform on-going trades, supervisory and administrative functions in a variety of capacities and departments. Hiring Hall staff are mainly used for larger capital construction projects and seasonal work. Remotes also routinely trains and mentors various trade apprentices, exposing them to a variety of challenging and unique work experiences.

More resources are required in P&C, Lines, Engineering and Billing/Customer Care areas over the plan period on an either a temporary or permanent basis as customer numbers increase, stakeholder expectations continue to grow, and greater complexity is introduced with operations in both the on and off-grid environments.

Performance Objectives

Performance objectives in 2022 reflect the strategies undertaken throughout the plan period. Maintaining a strong Safety focus will be required to ensure our Safety target of zero serious injuries is met. We will leverage the EHSMS to drive continuous improvement in all aspects of HSE performance. We will continue to track initiatives developed within the EHSMS to serve as a proactive measure of commitment to HSE improvements. Customer outreach initiatives are determined annually by the Management team based on customer survey results, customer advisory board input, conservation goals, community leadership and tribal council feedback, and staff suggestions to improve customer relationships. Remotes will continue to focus on improving reliability by measuring SAIDI, SAIFI and generation availability for its off-grid communities. Productivity measures will continue to highlight the importance of detailed design, stage-gate readiness and efficient execution of major projects. As well, Remotes will continue with its on-going commitment to no major spill events while managing operational spill risk. Overall, the 2022 performance objectives will be similar to 2021, as our core values and strategy remains unchanged.

2022 Scorecard – DRAFT

Strategic Objective		Performance Measure	Year to Date		Status	Year End	
			Actual	Target	YTD	Target	Forecast
Health & Safety	Create an Injury Free Workplace	Serious Injuries				0	
		Recordable Incidents				1	
		Near Miss/Safety Catches				TBD	
		HSMS Objectives and Achievements				Number of planned initiatives	
Customer Relations	Inspire Customer Loyalty and be a Trusted Partner	Customer & Community Outreach Initiatives				Number of planned initiatives	
Operational Excellence	Maintain/Improve System Reliability	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point				TBD	3-year average
		System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point				TBD	3-year average
		Generation Availability				99.5%	
Productivity	Improve Efficiency of Operations	Design & Planning				Project milestones	
		On time, on budget project milestones				TBD	
Environmental Stewardship	Protect the Environment for Future Generations	Litres lost to the Environment				100	
		Hydro One Spills				TBD	
		Significant Spills over 100L				0	
		EMS Objectives and Achievements				Number of planned initiatives	

▲ Below Threshold ■ Below Target ● Target ★ Exceeds

Appendix A: Remotes Budgeted Financial Statements 2022-2027

Statement of Operations	**2022 BUSINESS PLAN**							
	Actual	**Projection**	**Budget**			**Outlook**		
in $K	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Revenues	57,920	64,414	87,311	127,583	161,745	162,668	161,844	164,200
Energy - Off Grid	*20,339*	*21,114*	*20,464*	*15,663*	*8,877*	*6,718*	*6,817*	*6,917*
Energy - Grid	*1,835*	*1,990*	*2,715*	*8,074*	*14,347*	*16,522*	*16,943*	*17,365*
Subsidy	*35,223*	*35,223*	*35,223*	*38,554*	*38,554*	*38,554*	*38,554*	*38,554*
RRRP Variance	*(491)*	*4,774*	*27,998*	*64,377*	*99,012*	*99,899*	*98,553*	*100,386*
External	*1,014*	*1,313*	*911*	*915*	*955*	*975*	*977*	*978*
Costs								
OM&A	21,185	22,373	22,533	22,050	22,246	23,314	23,443	22,925
Distribution Sustainment	*3,634*	*4,140*	*3,910*	*4,759*	*5,000*	*5,491*	*6,142*	*5,195*
Distribution Customer	*1,524*	*1,276*	*1,449*	*1,535*	*1,548*	*1,565*	*1,592*	*1,616*
Generation Sustainment	*11,849*	*11,330*	*11,808*	*10,127*	*9,759*	*9,821*	*9,343*	*9,561*
Generation Development	*758*	*575*	*743*	*743*	*733*	*733*	*733*	*733*
DCAM Sustainment	*419*	*404*	*400*	*508*	*508*	*508*	*408*	*408*
Environment	*888*	*1,108*	*1,182*	*1,196*	*1,216*	*1,238*	*1,256*	*1,278*
Common	*717*	*1,667*	*1,459*	*1,541*	*1,700*	*1,754*	*1,785*	*1,886*
Other	*1,396*	*1,873*	*1,582*	*1,641*	*1,782*	*2,204*	*2,184*	*2,248*
Cost of power	1,779	1,792	2,795	8,162	14,106	15,954	16,351	16,898
Watay Transmission costs	0	0	21,285	66,000	103,695	103,695	103,695	103,695
Fuel used for electric generation	29,166	33,699	32,461	23,356	12,720	10,648	10,812	10,971
Depreciation and Amortization	4,065	4,616	6,005	5,640	6,766	6,981	5,762	7,911
LAR amortization	*870*	*1,332*	*2,606*	*1,883*	*2,503*	*2,593*	*1,037*	*3,028*
Depreciation	*2,834*	*2,990*	*3,052*	*3,430*	*3,745*	*4,160*	*4,489*	*4,634*
Asset removal costs	*361*	*294*	*347*	*327*	*518*	*228*	*236*	*249*
Financing charges	1,814	1,934	2,232	2,375	2,212	2,076	1,781	1,800
Loss on Disposal of Assets	(86)	0	0	0	0	0	0	0
Total Costs	57,923	64,414	87,311	127,583	161,745	162,668	161,844	164,200
Income before income taxes	**(3)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Income tax expense	(3)	0	0	0	0	0	0	0
Net loss	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Other comprehensive income	18	18	21	22	23	25	26	27
Comprehensive income	**18**	**18**	**21**	**22**	**23**	**25**	**26**	**27**

Balance Sheet	2022 BUSINESS PLAN							
	Actual	Projection	Budget			Outlook		
in $K	2020	2021	2022	2023	2024	2025	2026	2027
Assets								
Current assets:								
Inter-company demand facility	-	-	-	121	2,375	7,850	4,716	758
Accounts receivable	8,342	6,461	6,045	6,503	6,470	6,465	6,518	6,567
Fuel, materials and supplies	2,535	2,903	2,702	2,012	1,722	1,772	1,822	1,872
Income taxes receivable	20	-	-	-	-	-	-	-
	10,897	9,364	8,747	8,636	10,567	16,087	13,056	9,197
Property, plant and equipment	49,816	52,315	58,287	65,683	69,517	68,928	68,211	66,521
Other assets:								
Environmental regulatory asset	43,379	44,843	42,237	40,354	37,850	35,257	34,220	31,192
RRRP receivable	5,598	10,372	17,085	5,091	408	-	-	-
Other regulatory assets	1,156	830	786	744	686	627	565	497
Deferred income tax assets	4,493	4,480	4,467	4,454	4,441	4,428	4,415	4,402
Other assets	220	151	190	171	152	132	114	100
	54,846	60,676	64,765	50,814	43,537	40,444	39,314	36,191
Total assets	**115,559**	**122,355**	**131,799**	**125,133**	**123,621**	**125,459**	**120,581**	**111,909**
Liabilities								
Current liabilities:								
Inter-company demand facility	42	4,586	5,969	-	-	-	-	-
Accounts payable and accrued liabilities	9,394	9,286	8,316	9,224	9,363	7,864	9,944	9,956
Accrued interest	280	265	376	376	376	376	278	167
Long-term debt	-	-	-	-	-	10,000	10,000	-
	9,716	14,137	14,661	9,600	9,739	18,240	20,222	10,123
Long-term liabilities:								
Long-term debt	43,049	42,948	52,920	52,928	52,935	42,944	32,952	32,958
Post-retirement and post-employment benefit liability	17,898	18,647	19,470	20,352	21,277	22,242	23,248	24,295
RRRP payable	-	-	-	-	-	3,388	8,530	11,838
Regulatory liabilities	4,493	4,480	4,467	4,454	4,441	4,428	4,414	4,402
Environmental liabilities	40,515	42,237	40,354	37,850	35,257	34,220	31,192	28,243
	105,955	108,312	117,211	115,584	113,910	107,222	100,336	101,736
Shareholder's equity (deficit)								
Common shares	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Deficit	(4,651)	(4,651)	(4,651)	(4,651)	(4,651)	(4,651)	(4,651)	(4,651)
Accumulated other comprehensive loss	(461)	(443)	(422)	(400)	(377)	(352)	(326)	(299)
	(112)	(94)	(73)	(51)	(28)	(3)	23	50
	115,559	**122,355**	**131,799**	**125,133**	**123,621**	**125,459**	**120,581**	**111,909**

Statements of Cash Flows	2022 BUSINESS PLAN							
	Actual	Projection	Budget			Outlook		
in $K	2020	2021	2022	2023	2024	2025	2026	2027
Operating activities								
Net income (loss)	-	-	-	-	-	-	-	-
Environmental expenditures	(870)	(1,332)	(2,606)	(1,883)	(2,503)	(2,593)	(1,037)	(3,028)
Adjustments for non-cash items:								
Depreciation and amortization	3,704	4,322	5,658	5,313	6,248	6,753	5,526	7,663
Regulatory assets and liabilities	312	(5,913)	(4,063)	13,920	7,244	3,060	1,099	3,096
Other	27	2,494	(1,361)	(1,831)	(1,572)	3,106	2,904	1,186
Changes in non-cash balances related to operations	(5,650)	1,412	(242)	1,139	462	8,456	1,879	(10,199)
Net cash from (used in) operating activities	(2,477)	983	(2,614)	16,658	9,879	18,782	10,371	(1,282)
Financing activities								
Issuance of long-term debt	-	-	10,000	-	-	-	-	-
Repayment of long-term debt	-	-	-	-	-	(10,000)	(10,000)	-
Other	-	18	21	22	23	25	26	27
Net cash from financing activities	-	18	10,021	22	23	(9,975)	(9,974)	27
Investing activities								
Capital expenditures and future use assets	(4,006)	(5,545)	(8,790)	(10,590)	(7,648)	(3,332)	(3,531)	(2,703)
Net cash used in investing activities	(4,006)	(5,545)	(8,790)	(10,590)	(7,648)	(3,332)	(3,531)	(2,703)
Net change in inter-company demand facility	(6,483)	(4,544)	(1,383)	6,090	2,254	5,475	(3,134)	(3,958)
Inter-company demand facility, beginning of year	6,441	(42)	(4,586)	(5,969)	121	2,375	7,850	4,716
Inter-company demand facility, end of year	**(42)**	**(4,586)**	**(5,969)**	**121**	**2,375**	**7,850**	**4,716**	**758**

CUSTOMER SERVICE AND ENGAGEMENT STRATEGY

1.0 INTRODUCTION

Remotes' vision is to be a trusted partner to these communities, taking account of local priorities, listening to customers, and treating customers with sensitivity and flexibility. Remotes operates in all the communities it serves at their request and believes that all its communities have a choice of service provider, a belief demonstrated by the large numbers of Independent Power Authorities operating in the north. Consequently, Remotes works hard to establish and maintain long-term relationships with Band Councils, customers, and other stakeholders.

2.0 WORKING RELATIONSHIPS WITH BAND COUNCILS

Customers living on reserve comprise the majority of Remotes' customer base, about 90% of total customers. Remotes meets regularly with Band Councils and Band Administrators both in Thunder Bay and in the communities. Field staff stop by the Band Office to visit when they are on site and Band Councils are notified when crews will be in the community for planned work. Remotes' staff also communicate with Band Council members and staff regularly by phone or email. By working closely with Band Councils and by establishing positive working relationships, Remotes hears about community needs and helps communities understand what to expect in terms of reliability, customer, work program execution and programs for customers.

In First Nation communities, capital projects related to load growth are undertaken collaboratively with the Band Council, as the projects are funded and conducted only if requested by the First Nations. As part of planning for local and electrical infrastructure, Remotes meets with Band Councils to discuss peak load and the likely timing when an upgrade would be required, if the community is approaching restrictions. To forecast load and fuel deliveries, Remotes talks to Band Councils to understand community plans for housing and other infrastructure. Regular engagement also includes discussion on power outages including the root causes of events, discussions on fuel purchases and fuel levels at the plants, and discussions about the kind of work that is planned and required in their communities.

Remotes also works with Band Councils and related social service representatives on customer service issues. Remotes ensures that customers are set up correctly and recorded accurately in the Customer Information System by liaising with the local staff. This practice ensures that customers who are eligible, benefit from the HST exemption, the First Nation Delivery Credit and other social service support. It also helps to ensure that customer data is accurate and kept up to date if customers move.

Remotes' customers have a connection to the land and see environmental protection as a priority. Remotes understood this priority and made a commitment to reducing the impact of its operations on the environment. In 2017 Remotes registered to the new, rigorous, ISO 14001-2015 standard. Remotes invests in plant improvements to reduce the risk of spills; to reduce the severity of spills, by investing in spill-alarm systems; and to remediate contaminated lands. Projects to remediate lands require First Nations support and commitment. If available, equipment and materials such as gravel or biocells are rented or purchased from the First Nations. Remotes plans these projects with Band Councils and works together with them to carry them out.

As permitted by Section 13.2(d) of its Distribution licence, Remotes works closely with local Band Councils when planning and undertaking collection trips. Working with the Band Council is required, as Band Councils have the legal right to bar outside parties from reserve. Working closely with the Band Council also ensures that customers have opportunities and time to access available community support and OEB programs such as the Low-Income Emergency Assistance Program (LEAP) and the Ontario Electricity Support Program (OESP), so that the local government can advise Remotes of sensitive situations such as Elders or cases of hardship. Remotes believes that its collection practices respond to the needs of Band Councils and its customers.

Remotes has only eight unmetered loads for street light accounts within the communities we serve. Streetlights are well supported by the local Band Councils as they offer a broader public safety need to the communities. Streetlight programs are more fully discussed within the DSP. Given the narrow nature of unmetered accounts; discussion, and communication about them are only a minor subset of the broader communication with local Band Councils and not a significant customer engagement activity.

3.0 SUPPORTING THE LOCAL ECONOMY

From discussions with customers and Band Councils, Remotes sees and hears the need for economic development in the north and tries to address this need as part of the way it conducts business. First Nations are involved in Remotes' business as employees, contractors and labourers. Most suppliers are First Nation enterprises or have a strong First Nation component to their businesses. To take advantage of cost savings related to winter road transportation and to improve opportunities for local businesses, Remotes enters into mutually beneficial contracts to purchase fuel from up to five First Nations-owned fuel storage tank farms annually.

Given the inaccessibility of Remotes' service territory and the cost to transport staff and equipment, Remotes relies on local community members to work in its plants, respond to emergencies and read meters. Remotes' operators are the eyes and ears on the ground, offering information and advice on a wide range of community and customer issues. Operators have enormous responsibility for the safety and reliability of the electrical systems. Remotes' operations team work closely with these community members to train and support them in their day-to-day work.

As well, Remotes' REINDEER program (**R**enewable **E**nergy **IN**novation **D**i**E**sel **E**mission **R**eduction) was established to respond to the desire of its customers to reduce diesel use in their communities and to create opportunities for First Nations to share the economic benefits of renewable energy projects.

4.0 ENGAGEMENT WITH END USE CUSTOMERS

From time-to-time, Remotes holds community meetings with end-use customers. These meetings can be discussions of a project, a general information session about programs, services, or a celebration of a completed project such as a generation upgrade. Remotes also offers presentations to schools when staff are in the community doing other work, to teach local children about electrical safety. Remotes also participates in career fairs in the north to inform students about opportunities in the electrical field.

Remotes has a Customer Advisory Board (CAB) that usually meets once or twice a year. Starting in 2006, the CAB has offered advice from the perspective of ordinary residential customers on a wide range of business activities, including improvements to operator and meter reader training, electrical job opportunities, conservation programs, renewable energy, reliability, and the real-life impact of customer connection constraints. The CAB has had a positive impact on Remotes' business, in particular, on training programs for local operators and meter readers, as well as program promotion such as CDM, LEAP and OESP.

Remotes surveys its customers once every two years to determine overall customer satisfaction with its services and to get feedback on programs. Remotes uses a few of the survey questions to ask about specific ways that service can be improved and to identify customer knowledge of available programs and services. Based on the survey results, action plans are developed to ensure services reflect customer expectations and improve customer knowledge of programs such as LEAP and OESP are in place.

Further information about Remotes' outreach to customers can be found in DSP Section 5.2.2.1.

PURCHASE OF NON-AFFILIATE GOODS AND SERVICES

1.0 INTRODUCTION

This exhibit describes how Remotes purchases goods and services from third parties other than its affiliates.

2.0 THE PROCUREMENT OF GOODS AND SERVICES FROM NON-AFFILIATES

Remotes acquires materials and services from non-affiliates by using one or more of the following processes: request for information, request for proposals, request for quotes, request for pre-qualification, contract harmonization, direct negotiation (single sourcing) and sole sourcing process. The procurement of goods and services is consistent with the supply chain policy developed by Networks, which has been filed at Exhibit E, Tab 5, Schedule 2, Attachment 1 in EB-2021-0110. A copy has been included as Attachment 1 to this Exhibit. All transactions are compliant with Networks' procurement policy.

Remotes works with buyers in Networks' supply chain and procurement group when making purchases. Large purchases such as contracts for fuel and flights are conducted through extensive RFP processes, where potential suppliers are ranked based on pricing, proof of ability (resources, service, experience and quality), safety performance and Indigenous involvement in the business. Remotes leverages the bulk buying power of Hydro One and the existing Supply Chain infrastructure to secure routine purchases of materials, such as line supplies.

For services within communities, Remotes routinely supports local Indigenous business and local employment opportunities for services such as meter reading, operator services, fuel handling, forestry services and equipment rentals. Remotes enters into mutually beneficial fuel purchase agreement with local First Nation businesses that are able to secure and store winter road fuel.

All purchases of goods and services go through a rigorous quality control process and are reviewed by Law and Supply Chain to ensure value for money and adherence to Hydro One policies.

Purchases are authorized by the appropriate position identified in Hydro One's Expenditure Authority Register (EAR). The EAR defines approval authorities assigned to employees within Hydro One and it is a key element of the internal control framework. Employees, as stewards of the Company's assets, are expected to exercise prudent business judgment when delegating and exercising the authority limits in the EAR.

Supply Chain Policy

Purpose and Scope

The primary purpose of the Supply Chain Policy is to communicate and reinforce desired values and expectations of the supply chain activities of Hydro One Limited, its subsidiaries and the affiliates it controls (referred to in this document as 'Hydro One' or the 'Corporation').

This policy applies to Hydro One and its outsourcing partner.

Revision Statement

This policy has been revised to include additional key Supply Chain functions: Productivity Savings, Supplier Performance Management & Governance. In addition, links in section 3.0 References have been updated.

Principles

Supply Chain will:

- Acquire materials and services through a process that drives value for money, transparency to its internal customers, and builds mutually valuable relationships with key suppliers.
- Ensure the right materials and services are delivered to the right place at the right time in a cost effective manner.
- Source materials and services with consideration to health, safety and the environment and corporate social responsibility.
- Promote business and workforce development for Indigenous Businesses.
- Achieve operational excellence through continuous improvement in collaboration with Supply Chain's Customers and Suppliers.
- Manage its outsourcing partner to align with these principles.

1.0 Requirements

The key requirements of each Supply Chain function are as follows:

Strategy and Oversight:

- Provide a strategic, cost effective, data driven and analytical planning approach to Supply Chain processes.
- Direct continuous improvement initiatives to achieve operational excellence and cost effectiveness.
- Ensure an effective governance process is in place to manage change.

Sourcing:

- Develop and execute a strategic procurement plan to identify materials and services needed to meet business requirements at the best value for money.
- Employ a mix of procurement processes, including sole source, direct negotiation, and bidding processes that provide the best business outcome.
- Identify and attract qualified suppliers that provide quality products and services.
- Provide opportunity for increased Indigenous Business participation in the provision of products and services.

Purchasing:

- Process Purchase Requisitions on a timely basis to ensure that customer's needs are met.
- Promote improved requisitioning through effectively documented processes and education.

Inventory Management:

- ≠ Align to the Inventory Policy (SP0732).
- ≠ Manage inventory at optimal levels and locations to satisfy operations.
- ≠ Monitor and control the accuracy of inventory data.
- ≠ Re-deploy, return or dispose of material to maximize cost savings considering environmental impact.

Logistics:

- ≠ Determine the most efficient and economical method to store and distribute materials from Suppliers to Customers.
- ≠ Facilitate the movement of returnable containers to Suppliers.

Accounts Payable:

- ≠ Remit authorized and timely payments to Suppliers in accordance with the terms and conditions of the respective contracts.
- ≠ Capture payments accurately and completely in Hydro One systems, and ensure accurate account distributions.

Customer Service:

- ≠ Providing Source-to-Pay support for all internal customers
- ≠ Delivering value to all its internal customer and dedicated to providing excellent customer service

Productivity Savings:

- ≠ Leverage purchasing power across internal organizations and strategic sourcing events to obtain competitive prices and negotiate significant cost savings

Supplier Performance Management & Governance:

- ≠ Negotiating terms and contractual language that mitigate risks and ensures Hydro One's interests are protected.
- ≠ Ensuring Suppliers meet financial, health & safety, and insurance requirements.
- ≠ Providing supplier performance management to ensure Suppliers are fulfilling their contractual commitments to Hydro One.

Data Management

- ≠ Utilize business applications, information management methods, and data management tools to implement procedures and an infrastructure to support the integration and shared use of accurate, timely, consistent and complete Supply Chain Master Data.

2.0 Definitions

None

3.0 References

Expenditure Authority Register

Supplier Code of Conduct

SP0829 - Code of Business Conduct

SP0849 - Corporate Disclosure Policy

SP0732 - Inventory Policy

SP0733 - Inventory Procedure

SP1374 - Indigenous Procurement Procedure

SP0327 - Health, Safety and Environmental Policies

SP0312 - HSE Requirements for Purchase of Contractor Services

SP0826 - Sourcing Procedure

Requisitioner's Guideline

4.0 Document Management

Owner/Functional Responsibility	Director, Supply Chain
Approver	Vice President, Shared Services
Approval Date	April 2020
Effective Date	April 28, 2020
Last Reviewed Date	April 28, 2020
Next Review Date	April 28, 2022

5.0 Appendices

None

AFFILIATE SERVICE AGREEMENTS

1.0 INTRODUCTION

In accordance with the Affiliate Relationships Code (ARC), when Remotes provides services to or purchases services from affiliates, it does so in accordance with service agreements that meet the ARC requirements. The ARC sets out the standards and conditions for the interaction between electricity distributors and transmitters and their respective affiliated companies. Affiliate legal contracts, or further details on services being exchanged, are available upon request. This exhibit describes the current agreements between Remotes and its affiliates.

2.0 COMMON CORPORATE COSTS AND SHARED SERVICES

Hydro One has identified certain Common Corporate Functions and Services (CCF&S) and shared services that provide common benefits to all business units while minimizing costly and unnecessary duplication. Common Corporate Costs and Shared services are further described in Exhibit D, Tab 1, Schedule 8.

3.0 UTILITY SERVICES PERFORMED BY NETWORKS

Remotes also purchases services from Networks related to utility operations. Utility services are demand-based and vary with the work program and the availability of Networks staff to perform work. The costs for utility services are built into the Remotes annual work programs. Costs for services purchased are primarily based on the hourly labour rate and the cost of materials. Utility services provided by Networks include:

• Forestry services • Metering services • Training and Development services • Distribution Lines services • Work Management • Fleet services • Environmental services • Engineering services • Flight safety services • Distribution Planning & Technical services	• Joint Use services • Health and Safety services • Winter Road Transport, Logistic and stock keeping services • Generation Station services • Facility services • Helicopter services • Customer Communication services (including printing and mailing) • Watay Project Planning and Management

4.0 UTILITY SERVICES PERFORMED BY REMOTES FOR NETWORKS

Remotes performs work for Networks. Services provided are demand-based and vary with the work program and the availability of Remotes staff to perform work. Services performed are primarily based on the hourly labour rate and the cost of materials. Services provided by Remotes for Networks include:

- Metering/Technician Work
- Lines Work
- Training
- Flight Services
- Diesel Maintenance and Station Support

Additional information can be found in Exhibit F, Tab 3, Schedule 1 for Other Revenue and Exhibit D, Tab 2, Schedule 1 for Costing of External Work. Further information on related party transactions can be found in the 2021 Hydro One Remotes Financial Statements filed in Exhibit A, Tab 1, Schedule 7, Attachment 4[1].

[1] See Note 16 on pg. 23 of 2021 Financial Statement (Related Party Transactions), as well as finical statements for prior years; filed as attachments 1 through 3 of Exhibit A, Tab 1, Schedule 7.

CORPORATE ORGANIZATION CHARTS

1.0 INTRODUCTION

This schedule describes the current organization of Remotes' business, beginning with an overview of the parent company (Hydro One Inc.) and a brief summary of Hydro One Inc.'s' principal subsidiary businesses.

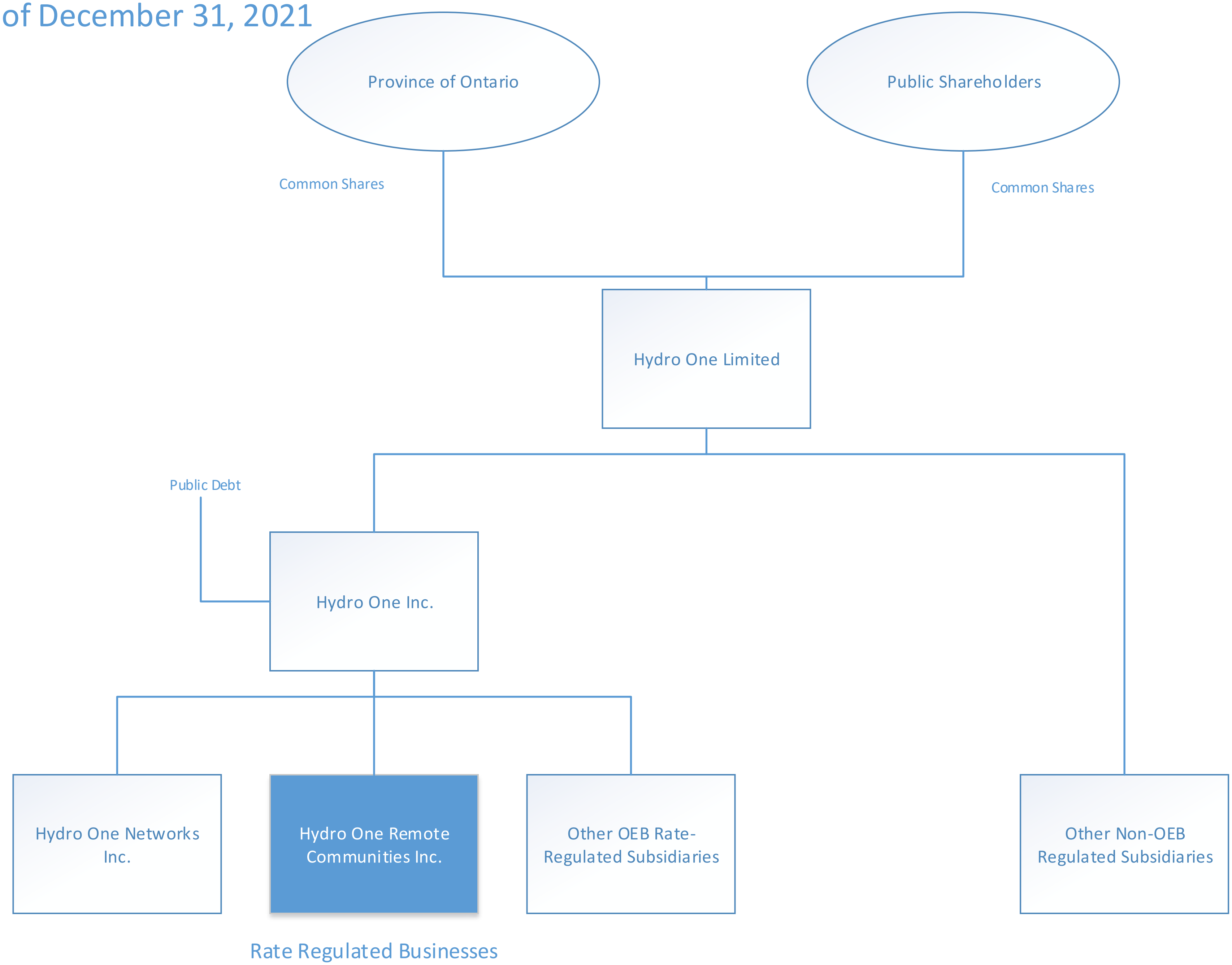
2.0 CORPORATE ORGANIZATIONAL STRUCTURE

Hydro One Inc. was incorporated under Ontario's Business Corporations Act and was incorporated on December 1, 1998 and at that time, was wholly owned by the Province of Ontario. On October 31, 2015, Hydro One Limited acquired all issued and outstanding shares of Hydro One Inc. from the Province. The principal businesses of the subsidiaries of Hydro One Inc. are the transmission and/or distribution of electricity to customers within Ontario.

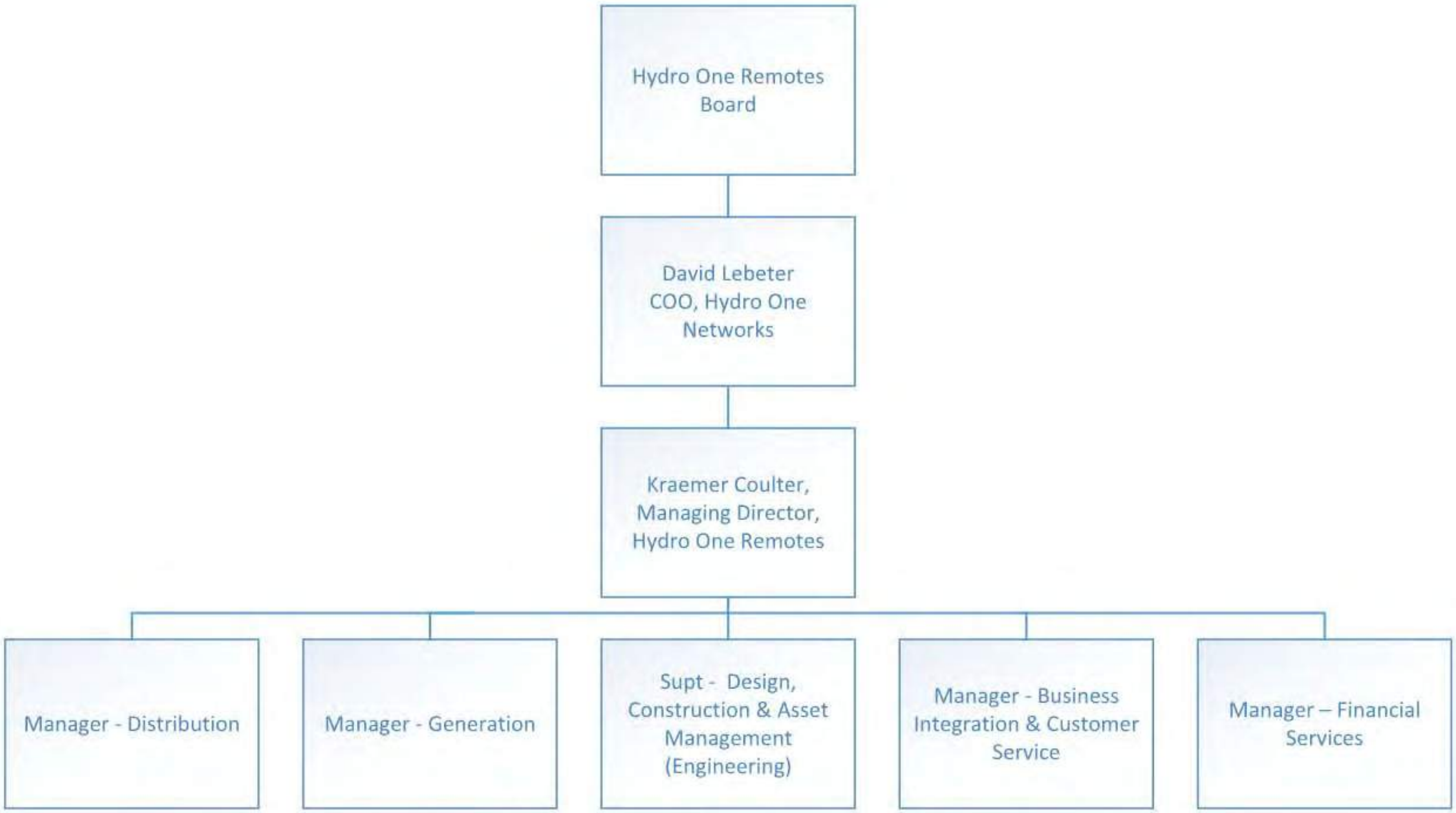
Attachment 1 of this Exhibit shows Hydro One Limited, Hydro One Inc. and its principal subsidiaries. Attachment 2 illustrates Remotes' organizational chart. Information on financial transactions between Remotes and its affiliates can be found in Exhibit A, Tab 5, Schedule 2.

This page has been left blank intentionally.

Hydro One Org Chart as of December 31, 2021



Remotes Organizational Chart



GOVERNANCE AND CONTROL FRAMEWORK

1.0 CORPORATE ORGANIZATION

The Corporate Governance structure and Internal Control Framework of Hydro One Inc. provide reasonable assurance regarding Remotes' effective and efficient operations, reliable financial reporting, and compliance with applicable laws and regulations. Hydro One Inc. is the parent and sole shareholder of Remotes, and Hydro One Limited is the parent and sole shareholder of Hydro One Inc.

Exhibit A, Tab 6, Schedule 1, Attachment 1 shows the organizational structure of Hydro One Limited as of December 31, 2021. This chart is simplified and does not include all legal entities within Hydro One Limited's organizational structure.

Corporate governance is the mechanism by which a corporation ensures independent oversight of management activities on behalf of the shareholder(s). For Hydro One Inc., the Board of Directors and its associated committees fulfill this objective and provide direction and accountability to senior officers to manage the company's business and affairs prudently and ethically, as well as the review and/or approval of mission, goals and business objectives, organizational authorities, and business plans.

Hydro One Inc.'s internal organization is led by its President and Chief Executive Officer whose direct reports include: the Chief Financial Officer; the Chief Operating Officer; the Chief Corporate Affairs and Customer Care Officer; the Chief Safety Officer; the Executive Vice-President and Chief Legal Officer; the Executive Vice-President and Chief Human Resources Officer; and SVP Technology and Chief Information Officer.

Remotes also has its own board consisting of one officer and three directors. The Chair of Remotes' Board of Directors is the Chief Operating Officer of Hydro One Inc. The accountabilities and responsibilities of Remotes' officer and directors include strategic support, the approval and adoption of a business plan that is included in Hydro One Inc.'s consolidated plan, oversight of risk management, and review of Remotes' overall business performance.

2.0 INTERNAL CONTROL FRAMEWORK

Internal controls ensure that Hydro One Inc. achieves its mission and goals, by enabling management to deal with rapidly changing economic and competitive environments, customer demands and priorities, and restructuring for future growth. Internal controls promote efficiency, reduce risk of asset loss, and help ensure the integrity and reliability of financial statements and compliance with laws and regulations. These controls of Hydro One Inc. extend to the operations of Remotes, as a wholly owned subsidiary of Hydro One Inc.

Hydro One Inc.'s Internal Control Framework has five components: (1) Control Environment, (2) Risk Assessment, (3) Control Activities, (4) Information and Communication, and (5) Monitoring. The framework further addresses the appropriate elements of each component at the entity (Board) level, corporate (senior management) level and operational (local) level. The framework is consistent with accepted external standards and control criteria set out by such standard setting bodies as the Chartered Professional Accountants and the U.S. Committee of Sponsoring Organizations of the Treadway Commission. Key components of the framework are described in more detail below.

The "Control Environment" refers to direction and oversight from the top of the organization. The control environment component in the framework captures the notion of ethical and prudent fiscal management as established by the Board of Directors and senior management and sets the tone for all financial and project management policies and practices established at lower levels. Regular education sessions on policies, processes and practices/procedures are also provided to all staff.

Hydro One Inc. has a formal Code of Business Conduct and a Whistle Blower Policy which have been issued to and must be complied with by all staff. The Code of Business Conduct requires all management employees to sign an annual compliance form to document that they have read, understood and complied with the Code, and that all conflicts or potential conflicts of interest have been disclosed. The Corporate Ethics Officer ensures that this process is performed on a timely basis and that a compliance register is maintained and submitted to the President and CEO of Hydro One Inc. In addition, Hydro One Remotes has a staff expectation document for all its staff, that is updated and reviewed annually. Lastly, individual performance contracts of management employees are intended to capture the understanding between a manager and a direct report as to the results expected and how such performance results will be achieved

"Risk Assessment" involves the identification and analysis by management of the key risks to achieving the company's business objectives. Such an assessment is performed, at least, annually, and provides the basis for business planning decisions. Programs that mitigate existing risks to acceptable residual levels, or provide mitigation for emerging risks, are captured in business plans. Projects and programs underway are regularly assessed for new and changing risks. Moreover, at the operational level, extensive emergency and contingency plans exist and are regularly tested and updated.

"Control Activities" refers to the systems, policies and procedures that ensure that management's objectives are achieved, and risk mitigation plans are carried out. Policies and procedures exist to govern annual, monthly and day to day operations at the business unit and local levels. Each revised policy has an issue date and last review date and are available on an internal web site.

One of the foundations of good control is the establishment of appropriate levels of authority for spending and other business decisions. The delegation and exercise of authorities are governed by 'Guiding Principles', the Code of Business Conduct, and policies and procedures. The approval of the business plans and budgets establish authorized spending levels.

The budgeting and business planning process is also a critical element of effective internal controls. Annually a budget and business plan are prepared and submitted to the Remotes Board for approval. The budget and business plan set the parameters of the company's activities for a specific fiscal period. Remotes' corporate business plan may be found in Exhibit A, Tab 3, Schedule 1, Attachment 1.

The Executive Authorities Register (EAR) delegates authorities from the Board to senior management. Further delegation exists at subsidiary and business unit levels to assign authorities from senior management to business unit, local levels or subject matter experts.

"Information and Communication" supports all other control components. Pertinent information must be identified, captured and communicated in a form and timeframe that enables staff to carry out their responsibilities. Communication occurs regularly to all staff with respect to new or changed policies, procedures or to select groups on various internal control matters. And, as noted previously, policies and procedures can be found on internal websites at most locations or are available in other formats.

"Monitoring" covers the oversight of internal controls by management or independent parties outside the process; or the application of independent methodologies, such as customized procedures or standard checklists, by employees within a process. Monitoring also includes assessing the quality of internal controls over time and implementing required changes.

Management provides assurance with respect to internal controls and the validity of financial statements. This includes information on legal claims, changes in accounting policies, practices, systems, and procedures that have occurred in the period, and financial accounting matters that could have a significant impact on financial statements. Management also provides assurance that internal control systems, policies and procedures are in place and functioning properly and financial statements are a true representation of the business.

Every month, Remotes and every other line of business are required to conduct a detailed review of financial results by comparing operating results to budgets and responding to variances. Project details with major accounts are reconciled monthly to source sub-systems and suspense accounts are also explained and reconciled. Monthly control reports related to key aspects of operations, financial and project activity are prepared centrally and delivered to managers for review and follow-up action as appropriate. A month-end close schedule is established to ensure timely production of financial statements. In addition, compliance testing of key financial activities is performed.

Compliance monitoring with respect to codes and policies is performed by multiple groups. Regulatory compliance is monitored by Regulatory Affairs. Internal Audit uses a risk-based audit approach for prioritizing audits and performs audits of areas of highest risk based on an annual program approved by the Hydro One Board’s Audit and Finance committee. Internal controls are reviewed on a recurring cycle, again linked to level of risk. Furthermore, regular review of all outstanding items from past audits is performed. Annual year-end audits are also conducted by Hydro One Inc.’s external auditor.

This page has been left blank intentionally.

PLANNING PROCESS AND ECONOMIC ASSUMPTIONS

1.0 INTRODUCTION

Business planning is performed annually and focuses on the development of a six-year plan which comprises a detailed plan for the first three years in the planning cycle and a less detailed outlook for the remaining three-year period. The planning cycle in 2021 pertained to the 2022-2027 period. The results as they apply to 2023 (test year) form the basis of this rate submission.

The typical annual business planning process consists of six stages:

1. Strategic direction and goals established.
2. Risk review and investment requirements.
3. Confirmation of strategic direction and goals with Hydro One Limited.
4. Development of economic outlook and forecast assumptions.
5. Development of plans and work programs.
6. Approval by Hydro One Remotes Board.
7. Approval by Hydro One Limited Senior Management and Board of Directors.

1.1 STRATEGIC DIRECTION AND GOALS ESTABLISHED BY SENIOR MANAGEMENT

Remotes' strategic direction and goals are reviewed and established by its management team and are confirmed by Hydro One. The strategic goals are used by planners as the business plan is being developed. Remotes' corporate vision and strategic objectives are shown in Exhibit A, Tab 1, Schedule 2.

1.2 RISK REVIEW AND INVESTMENT REQUIREMENTS

Annually, required investments are determined based on asset condition, engine hours, load growth and external factors (i.e., ISC funding, winter roads). Investments are then ranked against financial, operational, environmental, safety, and legal requirements and risks. The outcome of this process is a list of investments that is consistent with Remotes' strategic goals and considers levels of investment and associated risk mitigation against financial, operational, environmental, safety, regulatory and legal considerations. A final investment plan is then endorsed and confirmed by the Hydro One Inc. senior management team and approved by the Remotes' Board of Directors. The investment plan prepared during 2021 provides the basis for the 2022 plan.

1.3 DEVELOPMENT OF ECONOMIC OUTLOOK AND PLANNING ASSUMPTIONS

To facilitate the preparation of the business plan, an economic outlook is developed and included with the planning instructions issued. This includes forecasts of key economic statistics, interest rates, labour escalation rates, income tax rates, and cost rates for benefits.

1.3.1 CONSUMER PRICE INDEX

Remotes uses the Consumer Price Index (CPI) as a planning tool to forecast expenditure level changes. The CPI provides a broad measure of the cost of living. Through the monthly CPI, Statistics Canada tracks the change in retail price of a representative shopping basket of about 600 goods and services from an average household's expenditures: food, housing transportation, furniture, clothing, and recreation.

CPI-Ontario exhibits the inflationary environment in which Remotes operates. Historical CPI figures are from HIS Global Insight, April 2022.

For 2023, Remotes assumed 1.87% for both annual inflation and cost escalators for construction and OM&A expense growth based on the May 2021 projection during the 2022 Business Planning season. Subsequent to the preparation of the 2022 Business plan, both the CPI-Canada and CPI-Ontario rate are now experiencing decade high inflation rates, which will impact Remotes and other utilities.

Table 1 - Ontario Consumer Price Index

%	Historical Years				Bridge Year	Test Years				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CPI-Ontario*	2.4	1.9	0.6	3.5	1.61	1.87	2.00	2.04	2.04	2.04

1.3.2 COST OF CAPITAL

Remotes' cost of capital is as described in Exhibit E, Tab 1, Schedule 1.

1.3.3 INTEREST CAPITALIZED AND CAPITALIZATION OF OVERHEADS

Remotes' interest capitalized rates and capitalization of overheads are as described in Exhibit B, Tab 4, Schedule 1.

1.3.4 LABOUR ESCALATION

Specific details on annual labour escalation are provided below.

a) Society Staff

The Society of Energy Professionals Collective Agreement has reached an agreement to March 31, 2023. Economic increases were negotiated to be 1.5% for 2022.

b) PWU Staff

The Power Workers' Union Collective Agreement has reached an agreement to September 30, 2022. Economic increases were negotiated to be 2.2% for 2022.

c) MCP Staff

Remotes applied an average annual increase of 2% per year in base pay for 2022.

d) Incentive Plan Payouts

The MCP Short Term Incentive Plan payout under this plan is 15-20% for the 2022-2027 business plan term.

1.3.5 INCOME TAX RATES

Remotes' calculation of income taxes is as described in Exhibit D, Tab 5, Schedule 1.

1.4 DEVELOPMENT OF PLANS AND WORK PROGRAMS

During the planning process, plans and work programs are further refined consistent with the economic and forecast assumptions. As part of this process, sufficient detail is provided to facilitate preparation of the 2023 Rate Application. At the end of this process, senior management provides direction as necessary to balance the various factors under consideration including legal requirements, customer service levels, rate impacts and impacts on RRRP.

The operations, maintenance, and administration (OM&A) budget and the capital budget that result from this planning process are discussed at Exhibit D, Tab 1, Schedule 1 and the DSP respectively. Refer to Exhibit A, Tab 7, Schedule 3 for an overview of Remotes' project approval process.

The financial plan is prepared, incorporating OM&A and capital work program levels consistent with the investment plan, as well as forecasts of revenue, fuel, depreciation and amortization expense, financing charges, income tax, and working capital.

The resulting plan is reviewed and approved by the Remotes' Board. As necessary, underlying assumptions are modified, and the results finalized and presented as part of the consolidated plan to the Hydro One Board of Directors. The 2022-2027 Budget and Outlook was approved by the Remotes' Board of Directors at its October 2021 meeting and the consolidated plan was approved by the Hydro One Board of Directors at its December 2021 meeting.

PROJECT AND PROGRAM APPROVAL AND CONTROL

1.0 INTRODUCTION

As described in Exhibit A, Tab 7, Schedule 2, there are several key steps within the overall business planning cycle that are typically completed prior to the development of the detailed project and program assessments. These prerequisite steps include needs identification, project/program prioritization and the development of preliminary work programs, based on estimates of project and program costs and benefits.

2.0 PROJECT AND PROGRAM APPROVAL

Once the preliminary plans have been accepted at the proof-of-concept stage, an analysis of costs, proposed accomplishments, benefits, and risk is completed for each program and for individual projects.

For work programs of an ongoing nature (such as engine replacements), the analysis associated with each program are included in Asset Planning Documents for review and approval. Programs are reviewed annually, considering factors such as regulatory requirements, business efficiencies, impacts on customers, reliability, environment, and safety along with any other relevant information. For specific improvement and facilities projects business cases are only completed during the detailed budgeting process in October of each year, when specific project scope can be determined.

For projects that are not routine and do not occur annually, Business Case Summaries (BCS) for individual project proposals are developed and assessed. Similar analysis is undertaken for these projects, but in more detail than for routine work. Factors such as the need for the investment including the implications of not doing the work, the anticipated results and the recommended solution and its cost are all considered. In determining the recommended solution, alternative approaches and project risks are considered. The factors considered include regulatory requirements, business efficiencies, impacts on customers, reliability, environment and safety and any other relevant information. The proposals are reviewed in a series of steps at the senior management and executive levels, depending on the dollar limit and the significance of the investment. The proposals are then approved consistent with the provisions of the Expenditure Authority Register (EAR), described in Exhibit A, Tab 5, Schedule 1. For programs, this analysis and approval is completed as part of the investment planning process. Strategic investments are reviewed and approved by the Remotes Board and the Hydro One Board of Directors. The BCS documents provided in the Distribution System Plan summarize the proposed projects and programs with expenditures exceeding Remotes' $673k materiality threshold.

Projects funded by ISC are all subject to the Hydro One internal approval process described above. ISC-funded projects must also be approved by the local Band Council and are also approved following ISC's own internal funding processes. ISC's funding practices consider alternative solutions, impacts on communities, and are reviewed and approved in a series of steps at ISC's senior management/executive level. Depending on the scale of the project, ISC-funded projects are subject to different steps, including design approval, Requests for Proposals; and monthly monitoring by ISC, the individual First Nation community, and other stakeholders. ISC-funded projects are described in more detail in DSP Section 5.4.

3.0 MONITORING AND CONTROL

Each month, management monitors year-to-date expenditures and accomplishments as well as projected year-end expenditures and work accomplishments. Deviations from plan are identified and corrective action taken.

If significant changes in cost, schedule or scope of a project are forecasted, an Interim Review of Variance (IROV) is prepared. An IROV is essentially an amended business case that is reviewed and approved based on the revised set of circumstances (cost, scope, or schedule). The IROV approval is in accordance with the limits set out in the EAR. Projects which cannot be re-justified are either scaled back, cancelled, or otherwise adjusted to conform to the new situation.

At the conclusion of the project, a Project Closure Summary (PCS) is prepared and approved in accordance with the EAR. This process ensures project oversight as well as accurate capitalization.

This page has been left blank intentionally.

RATE BASE AND WORKING CAPITAL

1.0 INTRODUCTION

This exhibit provides the forecast of Remotes' rate base for the 2023 test year and provides a detailed description of each of the rate base components.

In accordance with the Filing Requirements updated on April 18, 2022, the rate base underlying the test year revenue requirement includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are gross plant in service minus accumulated depreciation and contributed capital[1]. Working capital is calculated using the OEB's default factor of 7.5% as applicable to electricity distributors.

2.0 UTILITY RATE BASE

Utility rate base for Remotes for the test year is included in Table 1 below. Remotes' forecast rate base for the test year is $56,219k.

Table 1 - Remotes' Rate Base (*in thousands $)*

Description	Board Approved	Test Year	Variance $
	2018	**2023**	
Gross Plant	71,866	85,010	13,144
Accumulated Depreciation	(30,108)	(33,329)	(3,221)
Net Plant	**41,758**	**51,681**	**9,923**
Cash Working Capital	3,544	4,537	993
Distribution Rate Base	**45,302**	**56,219**	**10,916**
% Change			*24.1%*

[1] Contributed capital refers to amounts contributed by third parties to specific capital projects, e.g. Joint Use Assets, Customer Contributions

The mid-year gross plant balance reflects the capital expenditure programs forecast for the bridge and test years. These programs are described in detail in the company's written evidence and supporting schedules filed in the DSP at Exhibit B, Tab 2, Schedule 1, Section 5.2. The justification for capital projects in excess of $673k (0.5% of revenue requirement) are filed as DSP Attachments 1 to 9.

Continuity schedules are provided in Exhibit B, Tab 1, Schedule 2, Attachments 1 through 6.

Table 2 - Continuity of Fixed Assets Summary (*in thousands, $)*

Description	Board Approved	Historic				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Opening Gross Asset Balance	70,664	67,967	69,105	69,422	71,600	75,927	80,236
In-Service Additions	3,197	4,455	3,071	2,557	5,821	5,769	12,502
Retirements	(793)	(3,016)	(3,041)	(379)	(1,494)	(1,460)	(2,955)
Adjustments	-	(301)	287	-	-	-	-
Closing Gross Asset Balance	73,068	69,105	69,422	71,600	75,927	80,236	89,783
Mid-Year Gross Asset Balance	71,866	68,536	69,264	70,511	73,764	78,082	85,010
$ Change (2023 Test vs. 2018 Board Approved)							*13,144*
% Change (2023 Test vs. 2018 Board Approved)							*18.3%*

In-service additions (ISAs) reflect the placing in-service of Remotes' capital programs and are not equivalent to capital expenditures due to the multi-year nature of capital projects with defined in-service dates. These programs are described in detail in DSP section 5.4.1.4. Variance explanations are provided based on capital expenditures. Actual to forecast capital expenditures for each year between 2018 and 2022 are explained in DSP section 5.4.1.

The year over year differences in ISAs is due to timing of when the assets were placed into service. Large generation projects, which is Remotes' most significant capital component, are often multiple year projects, given long lead times, winter road shipping, and construction timelines. The major ISAs for each year are provided in the table below, which show the drivers of the year-over-year changes in ISA values.

Table 3 - Major ISA Additions by Year

2018	Marten Falls B Unit engine replacement ($1,288k), Hillsport bulk tank upgrade ($473k), and SCADA upgrades ($394k).
2019	Big Trout Lake B Unit engine emergency rebuild ($491k) and 3 major engine overhauls ($938k).
2020	3 major engine overhauls ($1,095k), SCADA upgrades ($507k), and stack extension project on the Wapekeka diesel generating station ($605k).
2021	3 major engine overhauls ($1,269k), Armstrong day tank replacement ($762k).
2022	Deer Lake C Unit engine replacement ($2,064k), Wataу grid connection of 4-pole cluster project ($455k), and Wapekeka staff house renovation ($667k).
2023	Big Trout Lake A Unit engine replacement ($5,272k), bulk tank replacements in Oba and Lansdowne ($839k), Sultan hydel controls ($398k), Wataу grid connection of 4-pole cluster project ($1,958k), and Beaverhall facility expansion ($1,967k).

Retirements in 2018 and 2019 are higher than typical when compared to all other years mainly due to an increased volume of retirements related to engine replacements. Retirements in 2018 are related to Armstrong generation assets, whereas 2019 retirements are related to Big Trout/KI and Bisco generation assets.

The nature and composition of Remotes' assets are described in detail in DSP section 5.3.2.2

3.0 WORKING CAPITAL

Working capital is at 7.5% of eligible OM&A expenses. A detailed calculation is found in Exhibit B, Tab 1, Schedule 2, Attachment 5.

Table 4 - Working Capital Calculation (in thousands, $)

Total Eligible OM&A Expenses	60,498
Working Capital Allowance @ 7.5%	4,537

This page has been left blank intentionally.

HYDRO ONE REMOTES CAPITAL EXPENDITURES COMPARISON, STATEMENT ON WORKING CAPITAL, IN-SERVICE ADDITIONS AND CONTINUITY SCHEDULES (P.P.E, ACCUMULATED DEPRECIATION, CONSTRUCTION WIP) 2018 TO 2023

Attachment 1: Comparison of Capital Expenditures - Historical (2018-2021), Bridge (2022) and Test (2023) Years

Attachment 2: Continuity of Property, Plant and Equipment - Historical (2018-2021), Bridge (2022) and Test (2023) Years

Attachment 3: Continuity of Accumulated Depreciation - Historical (2018-2021), Bridge (2022) and Test (2023) Years

Attachment 4: Continuity of Construction in Progress - Historical (2018-2021), Bridge (2022) and Test (2023) Years

Attachment 5: Statement of Working Capital – Test Year (2023)

Attachment 6: In-Service Additions - Historical (2018-2021), Bridge (2022) and Test (2023) Years

This page has been left blank intentionally.

COMPARISON OF CAPITAL EXPENDITURES (2018-23)

This exhibit has been filed separately in MS Excel format.

CONTINUITY OF PROPERTY, PLANT AND EQUIPMENT

This exhibit has been filed separately in MS Excel format.

CONTINUITY OF ACCUMULATED DEPRECIATION

This exhibit has been filed separately in MS Excel format.

CONTINUITY OF PPE-CONSTRUCTION WORK IN PROGRESS

This exhibit has been filed separately in MS Excel format.

STATEMENT OF WORKING CAPITAL

This exhibit has been filed separately in MS Excel format.

IN SERVICE ADDITIONS

This exhibit has been filed separately in MS Excel format.

Hydro One Remote Communities

Distribution System Plan

2023 Cost of Service Application

Historical Period:

2018 - 2021

Forecast Period:

2022 – 2027

August 31, 2022

CONTENTS

LIST OF APPENDICES

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

Acronym	Meaning
ACA	Asset Condition Assessment
AUC	Asset Under Construction
AM	Asset Management
CAB	Customer Advisory Board
CAIDI	Customer Average Interruption Duration Index
CDM	Conservation and Demand Management
CHI	Customer Hours Interrupted
CI	Customers Interrupted
CIA	Connection Impact Assessment
COS	Cost of Service
DSC	Distribution System Code
DSP	Distribution System Plan
EHSMS	Environmental Heath & Safety Management System
EMS	Environmental Management System
EPRP	Emergency Preparedness Response Plans
ESA	Electrical Safety Authority
GHG	Greenhouse Gas
GS	General Service
GSU	Generator Step-up Transformers
HI	Health Index
HMI	Human-Machine Interface
HONI	Hydro One Networks Inc.
HSMS	Health and Safety Management System
IESO	Independent Electricity System Operator
IPA	Independent Power Authorities
RIP	Regional Infrastructure Plan
IRRP	Integrated Regional Resource Plan
ISC	Indigenous Services Canada
kV	Kilovolt
kW	Kilowatt
LDC	Local Distribution Companies
LEAP	Low-Income Electricity Assistance Program
LOS	Loss of Supply
MED	Major Event Day
MRPH	Maximum Reasonable Potential for Harm
MW	Megawatt
NA	Need Assessment
OEB	Ontario Energy Board
OESP	Ontario Electricity Support Program
OGUA	Off-Grid Utilities Association
OH	Overhead
OM&A	Operation, Maintenance & Administration
OSLP	Opiikapawiin Services LP
O&M	Operation and Maintenance

Acronym	Meaning
PAR	Progressive Aboriginal Relations
PLC	Programable Logic Controller
RBD	Radial Boom Derricks
REG	Renewable Energy Generation
REINDEER	Renewable Energy Innovation Diesel Emission Reduction Program
RIP	Regional Infrastructure Plan
ROC	Remotes Outage Committee
ROE	Return on Equity
rpm	Revolutions per minute
RRF	Renewed Regulatory Framework
RRRP	Rural or Remote Electricity Rate Protection
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SQR	Service Quality Requirements
TSSA	Technical Standards and Safety Authority
TWE	Transport and Work Equipment
UG	Underground
ULC	Underwriters Laboratories of Canada
Watay	Wataynikaneyap Power LP

5.2 DISTRIBUTION SYSTEM PLAN

Hydro One Remote Communities Inc. (Remotes) has prepared this Distribution System Plan (DSP) in accordance with the Ontario Energy Board's (OEB's) *Chapter 5 – Filing Requirements for Electricity Distribution Rate Applications – 2022 Edition for 2023 Rate Applications*, dated April 18, 2022 (the Filing Requirements) as part of its 2023 Cost of Service Application (the Application). Remotes retained METSCO Energy Solutions Inc. (METSCO) to advise on and assist with the preparation of the DSP.

The DSP is a stand-alone document that is filed in support of Remotes' Application. The DSP's duration is ten years in total, comprising a historical period and a forecast period. The DSP covers the historical period of 2018 to 2021 and a forecast period of 2022 to 2027, with 2022 being the Bridge Year and 2023 being the Test Year.

Historical Period				Bridge Year	Test Year	Forecast			
Actuals				*Forecast Period*					
2018	*2019*	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*

$\underbrace{2023 \quad 2024 \quad 2025 \quad 2026 \quad 2027}_{\text{DSP Plan Period}}$

Figure 5.2-1: DSP Duration

The DSP contents are organized into three major sections:

- Section 5.2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement.
- Section 5.3 provides an overview of asset management (AM) practices, including an overview of the assets managed and asset lifecycle optimization policies and practices.
- Section 5.4 provides a summary of the capital expenditure plan, including a variance analysis of historical expenditures, an analysis of forecast expenditures, and justification of material projects above the materiality threshold.

The materiality threshold for Remotes is $673,000 and detailed descriptions of specific projects exceeding the materiality threshold are provided in Appendix A. Other pertinent information relevant to this DSP is included in the Appendices.

This DSP follows the chapter and section headings in accordance with the Filing Requirements.

5.2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW

5.2.1.1 Description of the Utility Company

Remotes generates and distributes electricity to customers in 21 off-grid communities and is also the distributor to one community connected to the province's electricity grid. In year 2021, Remotes served a total of 4,368 customers. Remotes is entirely debt-financed and operates as a break-even company with no return on equity (ROE).

Remotes is driven by its corporate vision and mission. Together, they provide the basis to deliver on targeted strategic goals and performance objectives. Remotes' Corporation vision, mission and strategic goals are summarized in Figure 5.2-2.

Corporate Vision: We will be the leading electrical utility and a trusted partner to remote communities in Ontario's North.

Corporate Mission: We supply safe, reliable and affordable electricity to remote communities by focussing on continuous improvement, operational excellence and outstanding customer service.

Strategic Goals: Consistent with Hydro One's overall goals and with our vision and mission, Remotes' current business plan is designed to meet the following objectives:

- Create an injury-free workplace and protect the safety of the public
- Supply safe, reliable, and affordable electricity to our customers
- Offer an exceptional customer experience
- Build strong, respectful relationships with community leaders
- Improve the safety, reliability and efficiency of distribution and generation systems
- Build a culture of actively engaged employees, with the skills and ability to respond to our customers' needs
- Protect and sustain the environment for future generations

Figure 5.2-2: Remotes' Corporate Vision, Mission, and Strategic Goals

Remotes' vision, mission and strategic goals is strongly aligned to the four key objectives from the OEB's Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (RRF), which includes customer focus, operational effectiveness, public policy responsiveness and financial performance. Unique to Remotes would be a need for enhanced public policy responsiveness, given Remotes' customer base and the added stakeholder involvement relative to other similar sized local distribution companies (LDCs). Financial performance is also distinct given Remotes' break-even business model. Remotes must continually strive to achieve a balance between rate payer impact and operational performance, customer, community, and stakeholder expectations.

Remotes functions in a unique environment. Extremely low customer densities, a harsh climate, logistical challenges related to transportation, the absence of an integrated transmission system in the majority of locations, and complex funding arrangements with third parties set Remotes apart from other LDCs.

Among the communities currently served by Remotes, 17 are First Nation communities, isolated and scattered across Ontario's far north. These communities face many challenges and are economically disadvantaged. In addition, 14 communities are not accessible by year-round road and can be reached only by aircraft, winter roads or, in the case of two communities, by barge, air, or winter road. The size and isolation of Remotes' service territory also means that the transportation and accommodation of staff, fuel, and equipment are key drivers of its costs. The company's reliance on winter roads for access to communities is also a major driver of work scheduling and completion activities, as scheduled projects may require deferral where winter roads cannot be constructed due to weather conditions, leading to project deferrals and the ensuing higher fuel and maintenance expenditures.

Remotes inherited Ontario Hydro's obligations to provide electricity to off-grid communities, whose obligations were originally negotiated with the federal and provincial governments. Under these arrangements, the federal and provincial governments funded the original capital installation of facilities. In First Nation communities, the arrangements with the federal government (the Agreements), through Indigenous Services Canada (ISC)[1] remain in place. The Agreements specify that Remotes is responsible for funding the ongoing operation and maintenance (O&M) of the system and that ISC is responsible for funding capital related to system expansions and capital capacity upgrades under Generation System Service. In the 1990's, ISC devolved responsibility for community infrastructure to First Nation communities. ISC now transfers funding to First Nations, who are responsible for administering most of the ISC's program and project funds. Therefore, Remotes' asset planning is a three-party process involving First Nation Band Councils, ISC, and Remotes. The certainty, timing and amount of funds available from ISC for funding upgrades is limited by overall funding constraints. Funding for new stations and larger engines must compete with larger federal commitments, other departmental priorities and may not be available in the year investment is required.

Remotes is wholly-owned by Hydro One Inc., which also owns 100% of Hydro One Networks Inc. Hydro One Inc. is, in turn, 100% owned by Hydro One Limited, whose ownership is split between public shareholders (through a Toronto Stock Exchange listing) and the Province of Ontario. As a subsidiary of Hydro One Inc., Remotes has access to operational, legal, regulatory, and financial expertise in the energy industry, and to leading technology and world-class expertise in innovation, engineering, and design. As a small business, Remotes understands its customers and works closely with them. The corporate structure is shown in Figure 5.2-3 below.

[1] Indigenous Services Canada was previously known as Indigenous and Northern Affairs Canada (INAC).

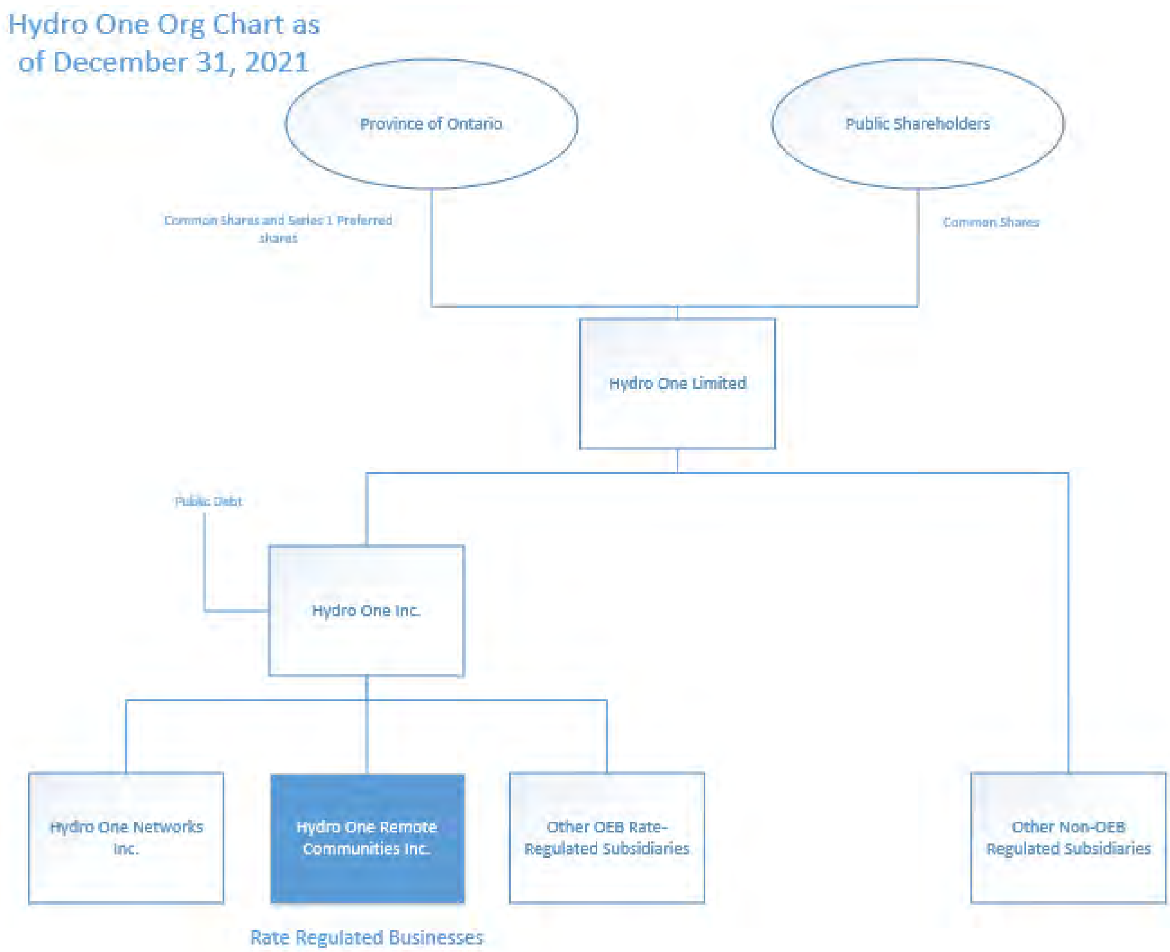


Figure 5.2-3: Hydro One Inc. Corporate Structure

Remotes is licensed to provide both generation and distribution services outside of the competitive electricity market through its licences ED-2003-0037 and EG-2003-0138, which identify its service territory and generation facilities. Remotes is obligated to maintain system integrity and to comply with codes, legislation, regulations, and market rules. Due to the unique nature of its business, Remotes is exempt from certain requirements that are not applicable. This includes but is not limited to certain performance metrics (e.g., efficiency assessment, total cost per customer and km of line, and certain financial ratios), certain service quality requirements (e.g., high voltage connections, metrics related to appointments, telephone call abandon rate, and emergency urban response) and the new energy data (i.e., Green Button) regulation under the *Electricity Act, 1998*. Additional detail on these exemptions is found within this rate filling submission.

5.2.1.2 Watay Project

The Wataynikaneyap transmission grid connection project (Watay Project) is a generational project that will revolutionize energy in Northern Ontario. The Watay Project corresponds to the construction of a transmission line that will connect 16 remote First Nation communities in Northern Ontario to the provincial Ontario Power Grid between 2022 and 2024.

Of these 16 remote First Nation communities, ten communities are currently serviced by Remotes diesel generation. One of these communities, Pikangikum, is already grid connected but is expected to be re-connected using a higher voltage feed in 2022. The other six communities, which are currently unregulated Independent Power Authorities (IPAs), are anticipated to be both grid-connected and added to Remotes' service area by the end of 2024. The Wataay Project powerline route and soon to be grid connected communities are shown in Figure 5.2-4[2].

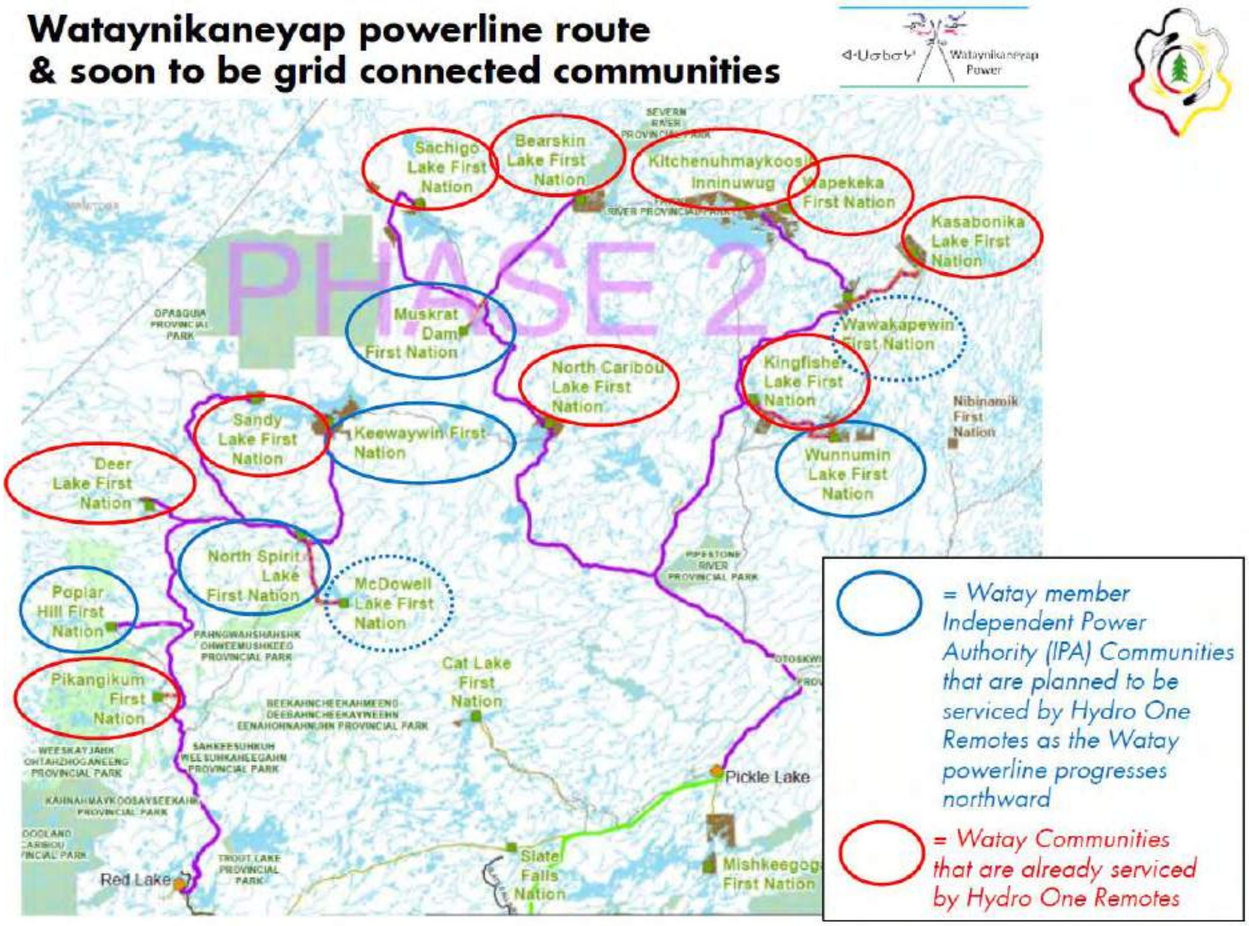


Figure 5.2-4: Wataynikaneyap Powerline Map

Over the DSP plan period, Remotes will see growth in its service territory and will transition to a transmission connected distributor while continuing to offer off-grid generation and distribution services. At the request of the communities connecting to the Wataay Project, Remotes has also made a commitment to provide backup power to the communities after grid connection to ensure that these communities continue to have access to reliable electricity in the event of any grid-related outages.

5.2.1.3 Service Area

Remotes' service area is spread out across Northern Ontario, as depicted in Figure 5.2-5. Remotes is currently licensed to generate and/or distribute within 21 isolated communities and one grid-connected community. These communities are shown in red in Figure 5.2-5. Collins and Whitesand, are served via the Armstrong distribution system. Among these communities, 17 are First Nation communities,

[2] This image identifies seven IPA communities, however only six are confirmed to be connecting to the grid. At the time of writing, there are no firm plans to connect the McDowell Lake First Nation.

and 14 are not accessible by year-round road (these communities must be accessed via air, winter road or barge in some cases).

Figure 5.2-5: Map of Remotes Service Territory

Cat Lake (currently served by Hydro One Networks), and six additional communities, which are currently unregulated IPAs, are anticipated to be added to Remotes' service area by the end of 2024. The communities currently serviced by Remotes, as well as those expected to be served by Remotes in the near term, are listed in Table 5.2-1.

Table 5.2-1: List of Communities Serviced by Remotes

Presently Served by Remotes	
Armstrong	Neskantaga First Nation (Landsdowne House)
Bearskin Lake First Nation	Marten Falls First Nation (Ogoki Post)
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	Oba
Biscotasing	Pikangikum First Nation – Grid Connected
Collins (Namaygoosisagagun First Nation)[1]	Sachigo Lake First Nation
Deer Lake First Nation	Sandy Lake First Nation
Fort Severn First Nation	Sultan
Kiashke Zaaging Anishinaabek (Gull Bay)	Wapekeka First Nation
Hillsport	North Caribou Lake First Nation (Weagamow/Round Lake)
Kasabonika Lake First Nation	Webequie First Nation
Kingfisher Lake First Nation	Whitesand First Nation [1]
Anticipated to be Served by Remotes in the Near Term[2]	
Muskrat Dam (2023) - IPA/Watay	Poplar Hill (2024) - IPA/Watay
Wunnumin Lake (2023) - IPA/Watay	North Spirit Lake (2024) - IPA/Watay
Wawakapewin (2023) - IPA/Watay	Keewaywin (2024) - IPA/Watay
Cat Lake (2023) - Currently grid connected & served by Hydro One Networks	

[1] Energy for Collins and Whitesand is provided by Armstrong.
[2] "IPA/Watay" refers to the IPA communities that will be grid-connected via the Watay Project. It is likely that the presented Watay connection dates will slip over time given construction and Covid delays. Remotes will continue to work with Watay and its partners to ensure timely connection.

5.2.1.4 Electricity Distribution

Remotes' 20 independent, self-sufficient, stand-alone generation/distribution systems (including Pikangikum) serve a total of 4,368 customers based on the 2021 year-end count. Figure 5.2-6 depicts the customer counts across those systems. Customers in Collins and Whitesand are included in the Armstrong count as they are served by the same generating station.

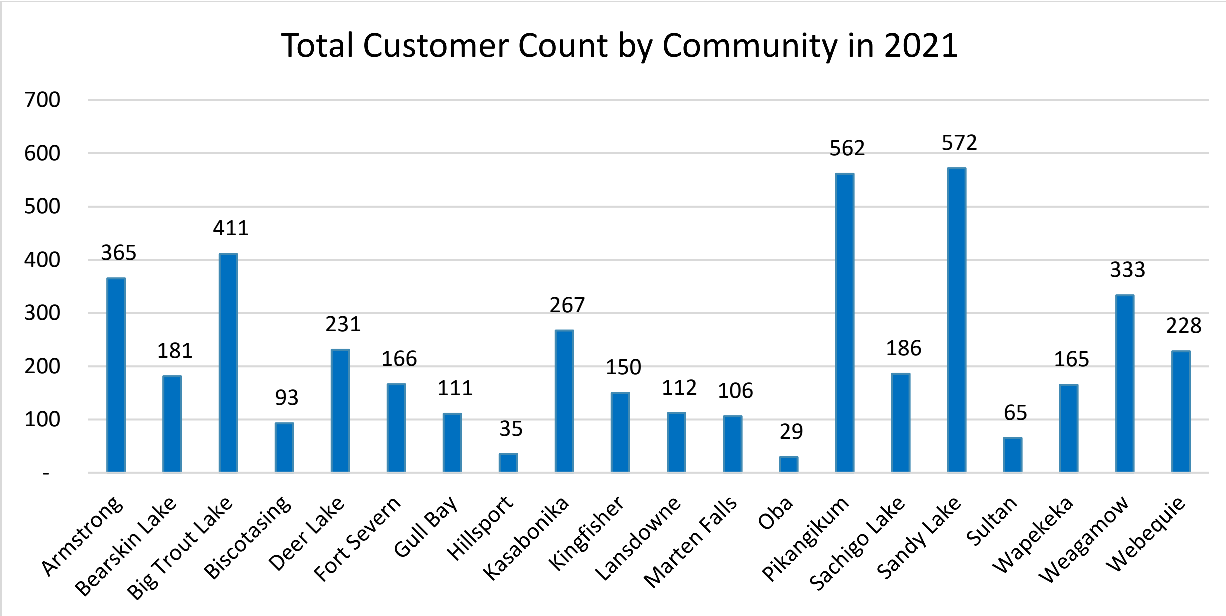


Figure 5.2-6: Total Customer Count by Community in 2021

These communities are expected to grow slightly over the forecast period, as shown in Table 5.2-2. The largest anticipated customer increase is due to the addition of seven new communities which are expected to join Remotes' service area over the forecast period: Cat Lake (2023), Muskrat Dam (2023), Wawakepewin (2023), Wunnumin Lake (2023), Keewaywin (2024), North Spirit (2024), and Poplar Hill (2024). As previously noted above, the six IPA communities (all excluding Cat Lake) are expected to connect to the Watay Project. Community growth in First Nation communities will continue to be largely influenced by Federal funding programs and initiatives.

Table 5.2-2: Forecast Customer Counts in the Years 2022 to 2027 by Community

Community	Year					
	2022	2023	2024	2025	2026	2027
Armstrong*	365	365	365	365	365	365
Bearskin Lake First Nation	175	175	175	175	175	175
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	421	426	431	436	441	446
Biscotasing	91	91	91	91	91	91
Deer Lake First Nation	247	250	253	256	259	262
Fort Severn First Nation	174	180	186	193	200	207
Kiashke Zaaging Anishinaabek (Gull Bay)	123	123	123	123	123	123
Hillsport	35	35	35	35	35	35
Kasabonika Lake First Nation	278	281	283	285	287	289
Kingfisher Lake First Nation	152	165	167	169	171	173
Neskantaga First Nation (Landsdowne House)	114	114	114	114	114	114
Marten Falls First Nation (Ogoki Post)	105	105	105	105	105	105
Oba	29	29	29	29	29	29
Pikangikum First Nation	575	593	611	629	647	665
Sachigo Lake First Nation	190	192	194	196	198	200

Community	Year					
	2022	2023	2024	2025	2026	2027
Sandy Lake First Nation	580	589	598	607	617	627
Sultan	65	65	65	65	65	65
Wapekeka First Nation	174	176	178	180	182	184
North Caribou Lake First Nation (Weagamow/Round Lake)	345	351	358	367	378	391
Webequie First Nation	213	214	215	216	217	218
Muskrat Dam (2023)	-	182	184	186	188	190
Wunnumin Lake (2023)	-	199	201	203	205	207
Wawakapewin (2023)	-	31	31	31	31	31
Cat Lake (2023)	-	260	263	266	269	272
Poplar Hill (2024)	-	-	172	174	176	178
North Spirit Lake (2024)	-	-	172	174	176	178
Keewaywin (2024)	-	-	184	186	188	190
Total	**4,451**	**5,191**	**5,783**	**5,856**	**5,932**	**6,010**

**Note: Customers in Collins and Whitesand are included in the Armstrong count.*

O. Reg. 442/01, a provincial regulation under the Ontario Energy Board Act, 1998, sets out two broad categories of customers that Remotes serves: customers who receive Rural or Remote Rate Protection (RRRP) (which includes residential, General Service, and street lighting “Non-Standard A” customers); and customers occupying government premises, defined as customers who receive direct or indirect funding from government (“Standard A” customers). Standard A customers include the Ontario Ministry of Transportation, Health Canada, and ISC. Customer classes in this category are defined depending on the access to the community (air or road) and the type of service (residential or General Service). Non-Standard A customers are all other residents and businesses who received subsidized rates through the RRRP. The Non-Standard A customers are grouped by the type of service: residential or General Service. Residential customer classes are divided into seasonal and year-round, while General Service customer classes are divided into single-phase and three-phase service. Table 5.2-3 summarizes the definitions of the customer classes served by Remotes.

Table 5.2-3: Summary of Customer Classes Served by Remotes

Customer Type	Definition	Customer Classes
Standard A	Government funded (e.g., Health Canada, ISC)	Residential – air access Residential – road access General Service – air access General Service – road access Grid Connected
Non-Standard A	Non-government funded	Residential year-round Residential seasonal General Service single-phase General Service three-phase
Street lighting	Community-owned public lighting	Street lighting

As depicted in Figure 5.2-7, the customer base has been relatively stable over the historical period but is expected to grow in the next five years with the addition of seven new communities. In 2019, Remotes began serving Pikangikum resulting in a large customer increase. Customer increases are also expected in 2023 and 2024 once Cat Lake and the IPA communities are served by Remotes.

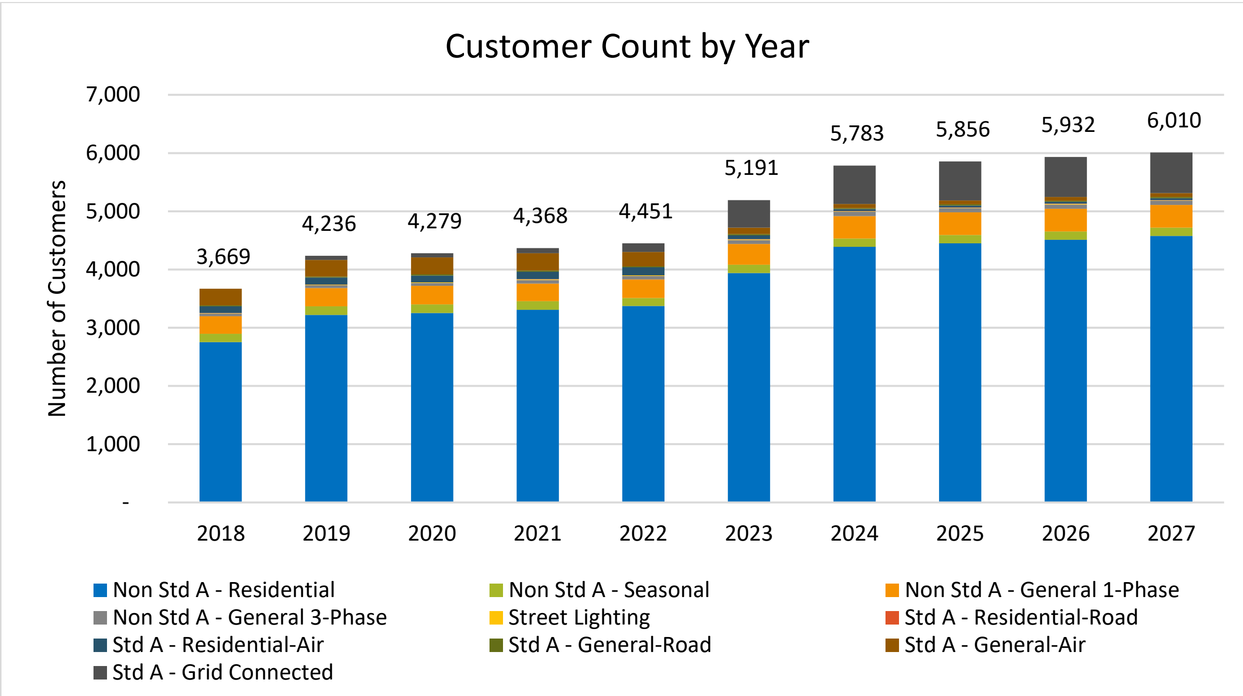


Figure 5.2-7: Year-end (2018-2021) and Forecast (2022-2027) Customer Counts

The total annual amount of energy delivered remained generally consistent over the historical period, as shown in Figure 5.2-8, but is expected to increase over the forecast period as new communities are added.

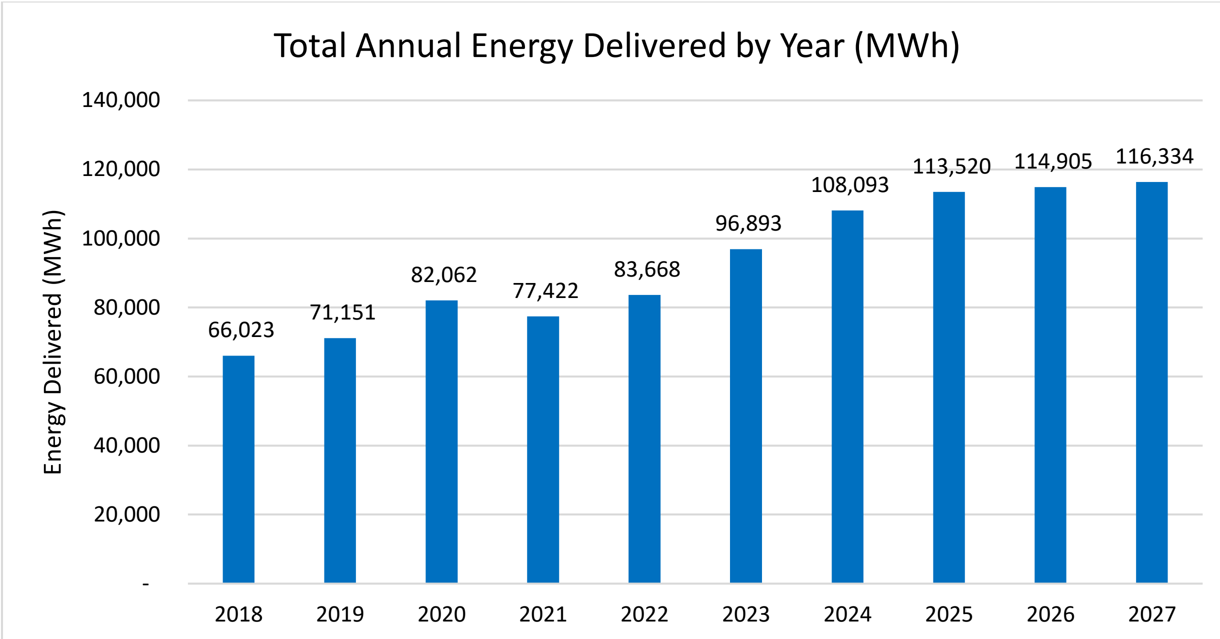


Figure 5.2-8: Total Annual MWh Delivered

5.2.1.5 Electricity Generation

Remotes generates electricity to meet its obligations under Section 29 of the Electricity Act, 1998 since the communities it serves are not connected to Ontario's bulk electricity system. The main source of electricity supplied to the communities are 57 diesel-fuelled generators with a combined capacity of 37,430 kW. Remotes also owns two hydroelectric generating facilities in Deer Lake sized 225 kW each and one in Sultan with 150 kW capacity.

There are also 18 customer owned solar renewable projects totalling 951.5 kW within Remotes' service territory, 12 of which are Net Metering projects with a total capacity of 308.5 kW, and six are standalone projects with a total capacity of 643 kW.

As noted above, Remotes will see growth in its service territory over the DSP plan period, will transition to a transmission connected distributor while continuing to offer off-grid generation and distribution services. At the request of the communities connecting to the Watay Project, Remotes has also made a commitment to provide backup power to the communities after grid connection to ensure that these communities continue to have access to reliable electricity in the event of any grid-related outages. As such, grid connection and the introduction of back-up power will drastically change the operating, maintenance, replacement, etc., and use of existing generation assets over the DSP plan period.

5.2.1.6 Capital Investment Highlights

To understand the key elements of Remotes' DSP, it is first important to understand the prospective business conditions driving the size and mix of capital investments required to achieve planning objectives over the forecast period. Capital investments are divided into three main categories of distribution, generation, and general plant. Each of these are discussed in a separate section below.

5.2.1.6.1 Distribution

Table 5.2-4 presents the distribution capital expenditures and system O&M costs for both the historical and forecast period. In accordance with the OEB requirements, the distribution capital expenditures are separated into three investment categories of system access, system renewal, and system service – although Remotes has no system service investments over the forecast period. General plant investments are described separately in Section 5.2.1.6.3.

Table 5.2-4: Historical and Forecast Capital Expenditures and System O&M – Distribution ($'000)

Investment Category	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022*	2023	2024	2025	2026	2027
System Access										
Gross	1,015	1,548	1,195	2,059	2,762	5,168	3,980	1,812	1,844	1,877
Contributions & Removals	(905)	(1,452)	(961)	(1,653)	(1,299)	(1,472)	(1,687)	(1,787)	(1,818)	(1,851)
Net	110	96	234	406	1,463	3,696	2,293	25	26	26
System Renewal										
Gross	457	547	1,158	989	860	1,063	1,142	944	966	969
Contributions & Removals	(260)	(151)	(819)	(578)	(238)	(265)	(283)	(267)	(272)	(277)
Net	197	396	339	411	622	798	859	677	694	692
System Service										
Gross	5,861	557	-	-	-	-	-	-	-	-
Contributions & Removals	(5,861)	(557)	-	-	-	-	-	-	-	-
Net	-	-	-	-	-	-	-	-	-	-
Total Capital										
Gross	7,333	2,652	2,353	3,048	3,622	6,231	5,122	2,756	2,810	2,846
Contributions & Removals	(7,026)	(2,160)	(1,780)	(2,231)	(1,537)	(1,737)	(1,970)	(2,054)	(2,090)	(2,128)
Distribution Capital, Net	307	492	573	817	2,085	4,494	3,152	702	720	718
Distribution O&M	3,723	4,317	5,158	4,181	5,359	6,294	6,548	7,056	7,734	6,811
Total Spend, Distribution	4,030	4,809	5,731	4,998	7,444	10,788	9,700	7,758	8,454	7,529

**0 months of actual expenditures included in 2022*

5.2.1.6.1.1 System Access - Distribution

Capital investments under distribution system access are largely driven by customer service requests, third party infrastructure development requests and mandated service obligations. The work performed under this category is largely recoverable from the requesting parties.

Distribution system access investments are a small portion of Remotes' spending over the forecast period except for the one-time increased non-recoverable spend in 2022-2024 relating to the wholesale metering cluster compound design and construction for those communities connecting to the provincial grid, which is driven by transmission regulatory requirements.

5.2.1.6.1.2 System Renewal - Distribution

Capital investments under distribution system renewal are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety, and sustainment of the distribution system. A large portion of the investments in this category falls under Distribution System Improvements, which includes replacements of aging or defective poles, conductor restringing, and pole re-alignments based on the asset condition surveys in the community. Betterments and system upgrades are made to facilitate system reliability and joint use of poles as well. Defective meter replacements, minor storm damage repair, damage claims, and small external demand requests also fall under this category.

Although the number of distribution assets under management by Remotes is expected to increase over the forecast period when new communities are added to the service area, no major increase in distribution system renewal spending has been planned since ISC is funding IPA upgrades to the distribution lines, to bring them to up to a strong standard, before they are transferred to Remotes.

5.2.1.6.1.3 System Service - Distribution

Distribution system service investments generally enhance the quality and reliability of the distribution system to meet operational objectives and address future electricity service requirements. In 2018 and 2019, Remotes connected KI and Wapekeka via the Tie-line project, which was a one-time event. Remotes is not expecting any distribution system service enhancements over the forecast period.

5.2.1.6.2 Generation

Table 5.2-5 depicts the generation capital expenditures and system O&M costs for both the historical and forecast period. The generation capital investments are divided into the system renewal and system service categories. Generation investments do not fall into the system access category, since these entail distribution system work to connect customers, such as metering and service layouts. General plant investments are described separately in Section 5.2.1.6.3.

Table 5.2-5: Historical and Forecast Capital Expenditures and System O&M – Generation ($'000)

Investment Category	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022*	2023	2024	2025	2026	2027
System Renewal										
Gross	3,298	3,804	3,077	4,200	6,062	4,868	4,726	1,786	2,060	1,273
Contributions & Removals	(260)	(592)	(324)	(830)	(473)	(1,116)	(1,138)	(19)	(25)	(34)
Net	3,038	3,212	2,753	3,370	5,589	3,752	3,588	1,767	2,035	1,239
System Service										
Gross	1,153	5,300	7,575	4,493	4,720	2,384	2,456	312	218	186
Contributions & Removals	(789)	(5,152)	(7,298)	(4,235)	(4,603)	(2,089)	(2,105)	0	0	0
Net	364	148	277	258	117	295	351	312	218	186
Total Capital										

Investment Category	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022*	2023	2024	2025	2026	2027
Gross	4,451	9,104	10,652	8,693	10,782	7,252	7,182	2,098	2,278	1,459
Contributions & Removals	(1,049)	(5,744)	(7,622)	(5,065)	(5,076)	(3,205)	(3,243)	(19)	(25)	(34)
Generation Capital, Net	3,402	3,360	3,030	3,628	5,706	4,047	3,939	2,079	2,253	1,425
Generation O&M	13,224	13,540	13,026	12,678	12,951	11,378	11,000	11,062	10,484	10,702
Total Spend, Generation	16,626	16,900	16,056	16,306	18,657	15,425	14,939	13,141	12,737	12,127

**0 months of actual expenditures included in 2022*

5.2.1.6.2.1 System Renewal - Generation

Generation system renewal investments contribute to the management of Remotes' generation units and are mostly driven by the condition and operating hours of the units. Investments under this category includes the overhauling and/or replacement of generator units.

Remotes is planning to undertake a number of generator overhauls over the forecast period in accordance with manufacturer recommendations, however a large portion of investments in this category are driven by end-of-life generator replacements. Planned replacements include the Armstrong A and B units, the Lansdowne House C Unit, and the Big Trout Lake A unit. Generation system renewal spending is expected to drop significantly between the years 2025-2027 once 10 of Remotes' existing communities are connected to the grid as assets change to back-up use and operate at reduced running hours. Generation system renewal spending is not anticipated for the new IPA communities as backup assets are expected to be in sound operating condition prior to transfer and last until at least 2030.

5.2.1.6.2.2 System Service - Generation

Capital investments under the generation system service category are mostly aimed at upgrade projects, which are driven by capacity requirements and are largely recoverable through ISC and community funding. The Gull Bay DGS Upgrade and the Lansdowne House DGS Upgrade projects are key capacity upgrade projects planned over the forecast period which are required to support the continued growth and development of the communities they serve.

5.2.1.6.3 General Plant

Table 5.2-6 depicts the general plant capital expenditures for both the historical and forecast period. General plant investments are modifications, replacements, or additions to Remotes' assets that are not part of its distribution or generation system. These investments include life extension of staff housing in each community, driven by the condition of the lodging, investments into storage buildings and other miscellaneous civil projects, and investments into minor fixed assets. A key investment within this category is the expansion/relocation of the existing Beaverhall facility in 2022-2023 to accommodate the growing workforce and the additional shop and storage space required to support the addition of seven new communities to Remotes' customer base.

Table 5.2-6: Historical and Forecast Capital Expenditures – General Plant ($'000)

Investment Category	Historical				Bridge	Forecast				
	2018	2019	2020	2021	2022*	2023	2024	2025	2026	2027
General Plant										
Gross	183	136	147	1,178	998	2,050	556	552	560	560
Contributions & Removals	-	-	-	-	-	-	-	-	-	-
Total Net Spend, General Plant	183	136	147	1,178	998	2,050	556	552	560	560

**0 months of actual expenditures included in 2022*

5.2.1.7 Changes since last DSP

Remotes' reporting, processes, practices, and inputs remain largely the same since the last DSP with only small continuous improvement and evolutionary changes. Items including the business plan, internal approval process, project management, program execution remain in place. Existing IT, data and computer systems with some enhancements over the period continue to support the business.

Three notable changes have materialized since the filing of the last DSP:

- **Customer Service and Community Relations Officer** – In accordance with the Settlement Proposal outcomes from Remotes' last DSP filing, Remotes has hired a permanent full time Community Relations & Customer Program Coordinator. This new role has many responsibilities including but not limited to developing and maintaining respectful relationships, promoting available conservation, affordability and community programs in the communities serviced by Remotes, and acting as a key resource to support communities and the business as a whole. The job description, including the complete list of accountabilities and selection criteria, was also circulated to settlement interveners for comments prior to it being finalized to ensure acceptance and alignment.
- **The Watay Project** – The Watay Project has impacted the DSP significantly in three ways. First off, it has drastically changed Remotes' business in future years by increasing distribution work and reducing generation work on both the O&M and capital going forward. Additionally, in recent years the pending Watay Project has changed selected generation assets and projects based on the remaining life and use. For example, shorter term and temporary generation solutions are now in play as well as the harvesting and extension of existing assets, which normally wouldn't have occurred under a prime power[3] situation. The introduction of back-up power services in selected communities has also impacted Remotes' asset decision making and the need for future work, and asset investments such as revenue metering as well as corresponding maintenance are required over the plan period to fully integrate Wataay and Remotes' business operations. Finally, Remotes will see increased complexity in the business as the service territory grows and transitions to a transmission connected distributor while continuing to offer off-grid generation and distribution services.
- **Governance** – in 2020, Hydro One leadership took a more active role in the strategic oversight of Remotes, with the strengthening of appointed board members and scheduled board-related

[3] Generators rated for prime power can be run on a 24 hours per day, seven days per week basis (i.e., 24/7), at near maximum loads. Prime rated generators provide baseload energy required in off-grid communities.

activities. The Remotes Board which includes three senior leaders external to Remotes has added an additional level of oversight to Remotes' strategic plans, performance measures and major asset investments through the business plan approval process.

In addition, since the last DSP over half of the business managers are new to both their jobs and the associated DSP requirements. Based on lessons learned, Remotes has taken a more active role in maintaining historical documentation as it relates to past projects and assets.

5.2.1.8 DSP Objectives

Remotes' DSP has been prepared to support the four key objectives from the OEB's RRF, which includes customer focus, operational effectiveness, public policy responsiveness and financial performance.

In addition to this, specific objectives of Remotes' DSP are listed below:

- **Meet Compliance Obligations** - All distributors are required to file a DSP when filing a cost of service (COS) application. Remotes need to meet all DSP filing requirements as per the OEB's Filing Requirements.
- **Meet OEB Desired Outcomes** - Highlight to the OEB and interested stakeholders Remotes' approach to evaluating performance, asset management, and capital investment plans.
- **Educate** - Inform and educate the OEB and interested stakeholders about Remotes' unique business features, which are unlike other LDCs. This includes but is not limited to generation, both on-grid and off-grid, First Nation involvement, multiple stakeholders, government funding models, logistical challenges, cost, and the importance of safe reliable power at reasonable rates to customers.
- **Highlight a Changing Business Model** – The Watay Project is a generational project that will revolutionize energy in Northern Ontario and Remotes' business. Over the plan period, Remotes will see increased complexity in the business as the service territory grows and transitions to a transmission connected distributor while continuing to offer off-grid generation and distribution services. In addition to the operational and business changes, the Watay Project drastically impacts the system-wide RRRP required by Remotes' business.

5.2.2 Coordinated Planning with Third Parties

Remotes regularly engages its customers and leaders of the First Nation communities it serves, federal government agencies such as ISC, provincial government bodies such as the OEB and the Ministry of Energy, the Independent Electricity System Operator (IESO), and other electricity distributors and transmitters. This DSP considers the outcomes of completed consultations, regional reports and plans, and continued coordination on future ongoing developments with third parties. The following sections describe the consultation activities that Remotes participated in or led that was part of this DSP.

5.2.2.1 Customer Engagement

Remotes involvement with its customers and communities is truly unlike other utilities. Remotes is very active in engaging with its customers and communities and value their feedback and involvement.

Remotes has regular communication with staff in First Nations communities and works closely with elected Band Councils to help them meet community electricity needs and preferences. The focus of communication efforts is with the First Nation communities that Remotes serve as they comprise approximately 90% of Remotes' customers. Each First Nation community has direct contact with several of Remotes' staff with communication taking place in many forms including email, phone calls, letters, conference calls, and face-to-face meetings. In the past, Remotes' First Nation Leadership have asked for more face-to-face meetings, so Remotes has increased the frequency of community visits and has started including its customer service staff in community meetings (pre-COVID).

In addition to community visits, Remotes also meets on occasion, usually alongside communities, with Tribals Councils who operate on behalf of communities in support of projects and providing services. These partners include Matawa First Nations Management, Keewaytinook Okimakanak, Shibogama First Nations Council, Windigo First Nations Council, and Independent First Nations Alliance. Remotes also work on occasion with Indigenous Political Organizations in the region such as Nishnawbe Aski Nation. Topics of discussion during these interactions vary by community and time to time. A few examples are noted in Table 5.2-7.

Table 5.2-7: Customer and Community Interaction

Category	Sample Topics of Discussion	
Generation	• Airport operations • Community emergencies/ disruptions • Diesel Plant Status • Fibre • Fuel purchase – winter road and barge	• Fuel quality • Generation trouble response • Hydroelectric development • Load growth, peak, and restrictions • Operating agreements
Distribution	• Asset data collection • Community projects & goodwill gestures • Connection costs & restrictions • ESA- Permits, Inspection, Coordination • Energy forecasts & community development	• Electrical contractors • Emergency response • Equipment rental • Damage claims
Billing	• Account statements • Address changes • Arrears • Billing & collections • Disconnections	• Heat traces • Long term payment plans • Meter reading and contracts • Move-in, Move-out • Rates
Community Relations/ Other	• Artists, Calendar distribution • Back-up power planning • Bill inserts- newsletter, other	• Distribution inquires • Emergency response • Energy summaries

Category	Sample Topics of Discussion	
	• Chief & council meeting • Complaints	• Permits • Sale of assets
Environmental	• Environmental compliance approval • Emissions • First Nations tank farm concerns • Spills • Community training and awareness	• Spill response • Waste/TDG • Water • General environmental awareness • Species at risk
Engineering	Back-up power planning & designs Community energy planning load Renewables- project planning and design Renewables- technical review and support Renewables- research and studies	Fuel systems & tanks Generation asset assessments Generation capacity and planning Generation upgrades Large customer loads review

In addition to these regular interactions, customers and communities are also engaged when a generation upgrade is needed in their community. Generation upgrade projects are often championed by the community who needs increased load capacity. When Remotes has determined that a generation upgrade is needed, it approaches the community to inform them, and the community must apply to ISC for funding. If the community decides not to support the upgrade, then they would not apply for funding and the project would not move forward. Therefore, all generation upgrade projects identified in this DSP are supported by the communities in which the upgrades will occur.

Given past challenges in both limited ISC funding and lengthy timing related to upgrades, Remotes has continued to take a more active role in generation upgrade project management, execution and construction. The modified upgrade process has been discussed and agreed upon by First Nations communities and ISC, reduces both the cost and time required for generation upgrades and has reduced the number of communities with connection restrictions. Remotes has also benefited in the new process by having more control of the design and asset selection, which benefits long-term reliability and operation.

Customer acceptance and feedback is a regular part of Remotes business. Remotes listens to its customers and makes significant effort to actively communicate through various communication channels and to work cooperatively on solutions when issues arise. Additionally, Remotes has regular meetings with the Customer Advisory Board and performs independent surveys as described in the following sub-sections.

5.2.2.1.1 Customer Advisory Board

The Customer Advisory Board (CAB) is made up of eight residential customers representing communities serviced by Remotes. Members are selected via an application process with Remotes' target communities to ensure wide, rotating representation among the 22 communities served with positions rotating every two to three years to ensure fresh perspectives. The customers must be in an unelected role in their community (i.e., not on Band Council), live or work in Remotes' service territory, be willing to attend meetings, be willing to offer constructive advice about Remotes' services and occasionally act as a local contact. There is an annual in-person meeting, and ongoing emails and calls through the year to discuss ideas. Board members are paid an honorarium.

The latest annual meeting of the board was on December 8, 2021.

<u>Purpose of the Engagement:</u>

The annual CAB Meeting facilitates feedback from the CAB on several topics, eliciting feedback from the group from a customers' perspective. There is at least one, and usually two to three staff members from Remotes presenting and participating in the discussions. Topics vary but generally include: available customer programs, overview of operations, community projects, customer communication effectiveness, and affordability. Feedback from this key meeting helps Remotes evaluate current programs and communication strategies, as well as elicit interesting new ideas from the participants on how to engage and assist customers.

Engagement Initiation:

Remotes initiates this annual engagement.

Final Deliverables / Outcomes:

After review of the discussions and tabulation of the CAB member evaluation forms from the December 8, 2021 annual meeting, the following recommendations were yielded for Remotes to consider:

- Bi-lingual communications (Oji-Cree, Ojibway, Cree) materials are important and appreciated.
- Bill inserts/newsletters need to be shorter, simpler and "punchier" with more frequent distribution. Long newsletters appear to not be well received.
- E-Billing (at minimum receiving a personal email displaying account balance) is desired by younger and more tech savvy customers and should be offered. Regular mail can be slow but carries bill inserts and provides some assurance that customers look at their bills, so consideration for Remotes to offer the addition of e-billing to regular mail bills, rather than replacement.
- Recommendation for Remotes to have a bi-lingual "Liaison" or a bi-lingual billing person that elders and other adults in the north could call to help explain their bills, as most adults use English as a second language, especially older adults.
- Seek opportunities to work more closely with other Community departments to better communicate Remotes' messages to customers: Ontario Works, Administration, Economic Development, and Energy Liaisons.
- Communication delivery: Local Facebook and local radio remain the best ways to get Remotes' messages out, followed by fax and emails to the band office (which then end up posted on Facebook). Explore using local radio to get messages out – perhaps monthly bulletin to arrange to have read on air by radio managers.
- Remotes' programs are viewed as very useful to customers and communities but need more education/engaging communication so that people learn about them.
- Energy Star Appliance Rebate Program – the need to work with the local stores was identified; customers are largely dependent on the store to bring in appliances for them to purchase. Exploration of a store rebate tied to each customer appliance rebate to increase energy efficient appliance availability in the north. For stores to be on board, do they require a rebate too?
- There is a lot of interest in Energy Conservation at the customer level, with the desire for more to be done in the areas of education, presentations/contests with school children, adult contests, energy kits, and giveaways.
- Contests - Hold contests for adults in the north – CAB members thought they would be well received and help raise awareness on topics/messaging Remotes is looking to share.
- New Website ideas including: Individual community information and local photos, "kid corner" section, list of Operators & Meter Readers with job descriptions, and how to pay your bill prominently featured.

- Education to Remotes' communities included in the Wataynikaneyap Power project; there seem to be some customers who are fearful of what will happen to bills, rates, changes, once the gridline comes in. Internally, Remotes has worked on education plans for IPA Communities coming over to Remotes, but there appears to be a gap in information for Remotes-served Watay communities that will require focus over the next few years.

Effect on the DSP:
When setting its priorities for planning, Remotes takes into consideration the priorities of its CAB. Remotes will be considering many of the ideas above during the DSP plan period designed to meet the customer needs as presented by CAB members. The ideas and initiatives noted above will impact Operations, Maintenance & Administrative (OM&A) costs, but are not likely to impact capital asset investment.

5.2.2.1.2 Customer Surveys

Remotes completed its 2021 Customer Service Research engagement in January 2022 with the support of Viewpoints Research. As part of this engagement, 184 customers were interviewed, including 164 resident customers, 19 business customers and 9 government-supported organizations. Engagement of the 184 customers was completed between December 13, 2021, and January 4, 2022.

Purpose of Engagements:
The goals of this research engagement were to explore customers' views on the accuracy of their bills, general perceptions of Remotes and its customer service, perceptions of the reliability of service provided, awareness of Remotes' electricity-related programs, and to explore preferred methods of communication and ways that Remotes could improve service, initiate activities, or make investments. Where possible, the survey tracks findings from previous waves of customer surveys conducted approximately every two years since 2003.

Engagement Initiation:
Remotes initiated the engagements.

Final Deliverables / Outcomes:

The key outcomes of the engagement were generally very positive. Specifically, customers feel that their electrical service is reliable, and customer satisfaction is at its highest recorded level with 96% of respondents being satisfied or very satisfied with their service. Of the 4% of respondents that were dissatisfied, the majority of complaints had to do with the cost of service (i.e., services are "expensive/costs too much in general").

When inquiring about activities or investments that could be undertaken to improve service within their communities, 71% of respondents did not offer a response. Of those respondents that did provide a suggestion, the most frequent suggestions were to improve services and lower costs (5% each), and upgrade equipment, advise about financial assistance programs, and provide information sessions (3% each). As overall customer satisfaction was at record levels of 96% satisfied or very satisfied, this aligns with the limited responses received around investments and activities that could be undertaken to improve service within the communities.

The Report on Customer Service Research 2021 Results can be found in Appendix B of this DSP.

Effect on the DSP:
Overall, Remotes has strong customer satisfaction with regards to transparency and communication with its clients, accuracy of billing information, and satisfaction with addressing service issues. Improvements could be made through increased availability of customer service in customers' Indigenous languages, which is currently under consideration. Due to the high level of overall

satisfaction, there was limited feedback on how to improve service to Remotes' customers, but the suggestions provided did help to inform Remotes' planning and capital investments for the forecast period. The survey confirmed that Remotes is generally doing the right things to meet the strong customer desire for safe, reliable and affordable power.

5.2.2.1.3 First Nation Chief & Council Leadership Surveys

Remotes completed its Chief and Council members leadership survey in January 2022 with the support of Viewpoints Research. Viewpoints Research engaged in a telephone survey with thirteen Chiefs and Council or key community leadership members representing communities served by Remotes. Interviews were conducted between November 23 and December 9, 2021.

Purpose of Engagements:

The goals of this engagement differed slightly from the Remotes customer survey completed in December 2021/January 2022. Specifically, the telephone survey with the Chiefs and Council leaders explored perceptions of electrical safety in their communities, awareness of Remotes' programs in communities, awareness of community investment initiatives Remotes is interested in developing, and perceptions of Remotes' responsibilities as the community utility. The survey also explored respondent's perceptions of changes coming to their communities upon completion of the Watay Project.

Engagement Initiation:

Remotes initiated the engagements.

Final Deliverables / Outcomes:

Respondents felt that the cost of electricity and the reliability of service were the two most important electricity issues in their communities, followed by electrical safety. This valued feedback confirms the desire for safe, affordable, and reliable power.

Remotes has multiple community and financial support programs in place for the customers that it serves. When discussing the awareness of these programs, most leaders are aware of Remotes' *streetlight and streetlight retrofit program* (69%), *community sponsorship program* (62%), *commercial lighting retrofit program for Band-owned building* (54%), *Low-Income Electricity Assistance (LEAP) program* (53%, 7 respondents), and 5 respondents (39%) were aware of the *Ontario Electricity Support Program (OESP)*. An area identified for improvement is to increase awareness of the Customer Advisory Board program, which will be addressed through future promotion and communication.

When inquiring about investment programs that Remotes makes into its customer communities most of the leaders are aware of Remotes' interest in developing *business partnerships with communities for fuel storage and renewable energy* (54%) and *training Hydro Operators receive through Remotes* (46%). However, increased awareness of investment programs in *Hydro One's status in the Progressive Aboriginal Relations (PAR) Program, as an environmental leader meeting ISO 1401 standards,* and *Hydro One's relationship with Indigenous-owned businesses* could be improved, with awareness amounting to 15%, 15%, and 0% respectively for each program.

Remotes inquired to the Chiefs and Council members about its responsibilities in the community, asking leaders to rate the utility as doing a very good, good, fair or poor job in each area. Remotes earned the highest ratings for *responding to emergencies* and *providing reliable electric power*, respectively with 92% and 93% very good and good responses. Remotes obtained good or very good ratings in other responsibility categories including *providing their community with information regarding planned power outages* (85%), *keeping in touch with customers* (78%), *responding to concerns raised by Chief and Council* (63%), and *working with Councils on project planning in communities* (54%).

However, room for improvement was identified with respect to Remotes' responsibilities for *cost estimates* and *timely service connection*, with only 38% and 39% of respondents giving positive ratings on these responsibilities.

The Watay Project is a major development in many communities in Remotes' service territory. As such, Remotes also asked questions to understand community preparedness for connecting to the provincial electricity grid. 89% of leaders felt their community is ready to be connected to the grid, but only 2 out of 9 (22%) felt they were *very ready*. Even though the majority of communities felt prepared for connecting, two thirds of leaders feel back up power is essential once their community is grid connected and anticipate maintaining existing generators to meet this need (67% of respondents). Leaders were also mixed on whether being on the provincial grid will result in increases to their hydro costs (33%), whether costs will stay the same (33%), or be lower (22%).

The Report on the Chiefs & Council Survey 2021 Results can be found in Appendix C of this DSP.

Effect on the DSP:
Overall, during engagement with the Chiefs and Council members of the communities that Remotes serves, satisfaction and reliability of service was high, with strong support for how Remotes responds to emergencies and provides reliable power. Improvements could be made by increasing awareness of community support and Indigenous-owned business partnerships that could exist with Remotes. Further transparency with Chiefs and Council members on investments in communities could be improved, as was seen by the lack of awareness of some investments and uncertainty on the costs or need for backup power associated with the Watay Project. Over the DSP plan period, Remotes will enhance its communication and awareness practices with communities on future investments and projects of mutual benefit to ensure community support and understanding of future projects remains strong. Ongoing communications initiatives will only minimally impact OM&A costs and are not likely to materially impact capital asset investment.

5.2.2.2 Engagement with Indigenous Services Canada (ISC)

Remotes operates in First Nation communities under funding agreements negotiated with ISC. Remotes and ISC representatives meet annually as part of the ongoing comprehensive planning program. Remotes also engages ISC regularly on matters concerning the execution of specific projects and community outreach initiatives.

Purpose of Engagements:
The purpose of these engagements is to review the available generation capacity based on the historical and projected peak loads in the communities to forecast and plan necessary generation capital projects in the indigenous communities Remotes serve. Collaboration with ISC ensures timely execution, cost effectiveness and reduces overall risk related to power supply in the remote communities. Additionally, discussions about community connections, housing and infrastructure growth are discussed so all parties are aligned on upcoming work.

Engagement Initiation:
Remotes typically initiates the engagements.

Other Participants in the Engagement:
Other participants in the engagements typically include ISC's capital management staff, technical support and the assigned First Nation project management team.

Final Deliverables / Outcomes:
A key outcome of this engagement is the alignment between ISC, the First Nation and Remotes on the need, scope, timing, and funding of generation capacity upgrade projects. Once an identified

project is approved, generation capital project meetings are held to initiate specific ISC-funded projects and to monitor project process. Once a project funding is initiated, Remotes participates and generally facilitates regular meetings. The meetings are held throughout the project to determine acceptable designs, timelines, and project progress. These meetings are also held to meet the needs of the First Nation project management team and ISC capital management staff.

Feedback from ISC and the communities about community connections, housing and infrastructure growth is also a critical element in both Remotes' load forecasts and generation capacity modelling.

Effect on the DSP:
Engagement with ISC is critical to the development and successful execution of generation upgrade projects listed in the system service category, given ISC's responsibility for capital project funding. Remotes and ISC have jointly identified the need to invest in Webequie First Nation in 2022, Gull Bay First Nation in 2022/23 and Neskantaga First Nation (Lansdowne House) in 2023/24 based on the available capacity and forecast load growth. These projects are entirely funded by the First Nation communities who, in turn, must apply for the funding from ISC. Remotes works closely with ISC and the communities to ensure the proper funding is in place for these projects to proceed. Without timely funding and project execution, Remotes is unable to connect new electrical services, slowing community development until generation capacity is increased.

5.2.2.3 Wataynikaneyap Power Transmission Connection Engagement

Remotes participates in all aspects of the engagements related to the Watay Project that, once complete, will connect 16 indigenous northern communities to the bulk transmission system. Out of these 16 communities, 10 are currently served by Remotes and 6 are unregulated IPAs being added to Remotes' customer base. The key engagements are related to transmission connection planning, transmission connection funding, regulatory support for IPAs, and diesel generation backup.

5.2.2.3.1 High Level Transmission Connection Planning

Purpose of the Engagement:
The purpose of this engagement is to co-operatively work together with all stakeholders on the Watay transmission connections that will ultimately expand the service territory of Remotes.

Engagement Initiation:
Multiple stakeholders initiate the engagement.

Other Participants in the Engagement:
Participants in the engagement are Watay, Watay services company Opiikapawiin Services LP (OSLP), IESO, First Nations representatives, Tribal Council Representatives as well as representatives from federal and provincial governments.

Final Deliverables / Outcomes:
The focus of this engagement is to co-operatively work together on the Watay transmission to ensure its success.

Effect on the DSP:
Over the DSP plan period, it is expected that Watay Power will construct a transmission line to connect 16 remote First Nation communities to the grid of which ten are currently served by Remotes and six are unregulated IPAs which will be served by Remotes following grid-connection.

The Watay Project has impacted the DSP significantly in three ways:

1. It has drastically changed Remotes' business in future years by increasing distribution work and reducing generation work on both O&M and capital expenditures going forward.

2. Additionally, in recent years the pending Watay Project has changed the selection of generation assets and projects based on their remaining life and use.
    a. Shorter term and temporary generation solutions are now in play as well as the harvesting and extension of existing assets, which normally would not have occurred under a prime power situation. Examples include the Sachigo Temporary generation unit which was put in place to bridge the capacity gap until grid connection, and the Big Trout Lake (KI) modular generating solution which was proposed as a more cost effective and efficient solution for providing backup power relative to a permanent building or expansion.
    b. The introduction of backup power services in select communities has also impacted Remotes' asset decision making and the need for future work. Prime power is no longer the driving requirement in these communities.
    c. Asset investments such as revenue metering as well as corresponding maintenance are required over the plan period to fully integrate Watay and Remotes' business operations. Revenue metering for example are basic legal and regulatory requirements that are necessary to operate.
3. Remotes will see increased complexity in the business as the service territory grows and transitions to a transmission connected distributor while continuing to offer off-grid generation and distribution services. This will impact Remotes' business and daily operations as Remotes works to meet the service requirements in both on-grid and off-grid communities.

5.2.2.3.2 Transmission Connection Funding and Settlement

Purpose of the Engagement:
The purpose of this engagement is to develop a funding agreement for the transmission connection project.

Engagement Initiation:
Wataay Power have initiated this engagement.

Other Participants in the Engagement:
Other participants in the engagement are Wataay Power, the IESO and representatives from federal and provincial governments.

Final Deliverables / Outcomes:
There are two major deliverables from this engagement. The first, is the overall funding structure of the Wataay Project, and the second, is the decision to flow Wataay funding through RRRP. Additional details can be found in the OEB Case Number EB-2018-0190[4].

More recent discussions have centered on future IESO settlement mechanics between the parties, which are shown in Figure 5.2-9.

[4] EB-2018-0190. Wataynikaneyap Power GP Inc. on behalf of Wataynikaneyap Power LP. Leave to Construct – transmission lines in northwestern Ontario. https://www.rds.oeb.ca/CMWebDrawer/Record?q=CaseNumber=EB-2018-0190&sortBy=recRegisteredOn-&pageSize=400

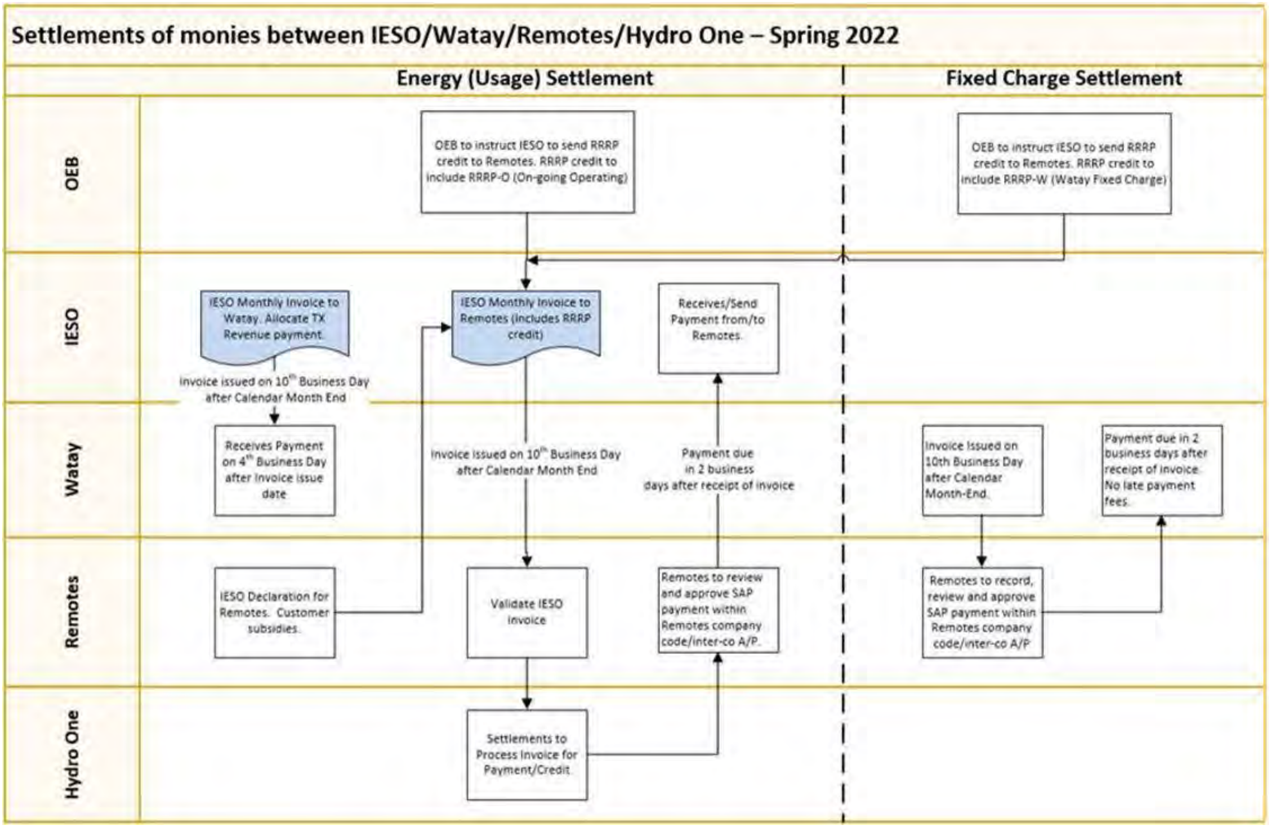


Figure 5.2-9: IESO Settlement Mechanics

Effect on the DSP:

The proposed cost recovery framework will charge the cost of the transmission facilities to Remotes as a direct expense, which will be recovered through the RRRP. As detailed in EB-2018-0190, Wataay has projected the cost to Remotes RRRP will grow to be approximately $104M per year over the Plan period. As well, transmission tariffs will be only partially offset by fuel and maintenance savings and will significantly alter the financial structure and cost effectiveness of Remotes.

Metering assets, settlement services, and revised accounting processes will all need to be implemented over the DSP plan period to adequately handle the required IESO settlement mechanics shown in Figure 5.2-9. Remotes will continue to work collaboratively with Wataay on topics of mutual interest and will also develop internal processes and practices to support this initiative.

5.2.2.3.3 Transitionary Requirements for Independent Power Authorities

Purpose of the Engagement:

The purpose of these engagements is to plan for and educate the IPA communities connecting to the Wataay Project on the provincial regulations and transition requirements related to electricity generation, transmission, and distribution. This work is done to ensure a smooth transition of the IPAs to Remotes' service and to ensure that the necessary assets, services and processes are in place to operate in a safe and efficient manner.

Engagement Initiation:

Wataay Power and the IPA communities, and their advisors (OSLP) initiate these engagements.

Other Participants in the Engagement:
Other participants in the engagement are Watay Power, ISC, Provincial Ministry of Energy staff, First Nation representatives and advisors.

Final Deliverables / Outcomes:
Remotes expects to integrate six new unregulated IPAs into its service territory over the next three years. Significant effort from Watay/OSLP and Remotes will be required to ensure that community readiness and a smooth transition to regulated service occurs.

During the historical period a draft transition template and legal agreement was drafted for transitioning IPA communities. This sets out the transfer requirements for service including the creation of a Hydro One compound, Electrical Safety Authority (ESA) inspection and delivery of customer records.

As part of this effort, Remotes has met and continues to meet with community leadership, IPA representatives and their advisors from North Spirit Lake First Nation, Wunnumin Lake First Nation, Muskrat Dam Lake First Nation, Wawakapewin First Nation, Poplar Hill First Nation, and Keewaywin First Nation. In addition to transition requirements, information shared included ESA requirements, Ontario regulations, OEB programs, and rate setting.

Proposed transmission development by Watay Power will drive major changes in Remotes' business, resulting in a significant increase in customers, new settlement and financial processes, increased interaction with government, First Nations, Tribal Councils, and industry regulators. Changes to operations include: on-grid operating and connection agreements; coordination with other distributors and transmitters; as well as new processes and assets.

Effect on the DSP
Remotes has performed a considerable amount of work to plan for and help the IPAs prepare for anticipated grid connection. Activities related to these engagements fall under the non-system O&M category and are not the focus of the DSP. However, the implementation of these activities will facilitate the successful connection of IPAs to the bulk electricity grid expected to take place in 2023 and 2024.

Similar to other grid-connected communities, metering assets, settlement services, and revised accounting processes will need to be implemented between 2022 and 2024 to adequately handle the required IESO settlement mechanics. Once IPA communities have fully transitioned, Remotes will also have more customers and assets to manage and maintain, which will drive further maintenance and operational spending in the DSP plan period.

5.2.2.3.4 Diesel Backup-Power Planning

Purpose of the Engagement:
This is an ongoing engagement to assess the feasibility of using diesel generators as a backup power supply to reduce the outage times for remote communities to be served by a new radial transmission line. The current focus has been on future implementation of backup power in both existing and IPA communities.

Engagement Initiation:
The IESO and Watay Power have initiated this ongoing engagement.

Other Participants in the Engagement:
Other participants in the engagement are the IESO, ISC, Tribal Councils, OSLP, and Provincial Ministry of Energy staff.

Final Deliverables / Outcomes:
During the historical period, Remotes was an active member in the backup planning group. It provided feedback to other backup studies and produced two of its own backup reports. The diesel backup study explored the development of technology options, regulatory considerations, capacity, load, costs, current and future financial responsibilities, and environmental considerations. The following diesel backup planning studies are appended to this DSP:

- Appendix D - Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities (December 2018)
- Appendix E - Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities Containerized DGS Option Annex (November 2019)
- Appendix F - Backup Power Plan for the Connecting Communities of the Wataynikaneyap Transmission Project (April 30, 2020)

In general, supply from local generation is more reliable than supply transmitted over long radial lines. Consequently, Remotes continues to work with both the federal and provincial governments, the local communities, and their project partners on providing reliable backup power in communities post-connection.

Effect on the DSP:
Remotes is actively working with stakeholders on providing reliable backup power in communities post-connection. Investments will be required in both capital programs and OM&A over the plan period to ensure safe and reliable backup. Capital backup transition activities are required to get the existing diesel stations in an operational state for backup power. Investments include heating the building, engine block heat, programming, station service, protections, communications and the decommissioning and removal of some fuel storage no longer required. OM&A will focus on operator training, testing, backup readiness and operating costs, including fuel, associated with operating backup power. The capital costs associated with the backup transition activities are expected to be fully recoverable from ISC via the First Nation, so Remotes will have additional work to perform during the DSP plan period but without any material noted OM&A or Net Capital impact.

5.2.2.4 Renewable Energy Generation

Purpose of the Engagement:
Remotes actively engages with First Nation communities, renewable developers and stakeholders on renewable energy generation (REG) projects.

Engagement Initiation:
First Nation communities, renewable developers and stakeholders initiate the engagement, through the Renewable Energy Innovation Diesel Emission Reduction (REINDEER) Program.

Other Participants in the Engagement:
Other participants in the engagement are the Provincial Ministry of Energy, IESO, ISC, and community representatives as required.

Final Deliverables / Outcomes:
As part of Remotes' regular business and promotion of the REINDEER Program, Remotes regularly field calls from First Nation communities, renewable developers and stakeholders on new technology, renewable energy concepts, and desired developments.

During the historical period, Remotes has collaboratively met with Whitesand First Nation, Fort Severn First Nation, and Gull Bay First Nation on their respective projects, which are not expected to be connected to the grid. Fort Severn First Nation and Gull Bay First Nation renewable energy projects are now in-service. Remotes took an active role in design and technical review of project plans, with integration into existing systems as the core focus given that Remotes must ensure safe and reliable power.

To date, Remotes has completed a Connection Impact Assessment (CIA) for a biomass project in Whitesand First Nation and has assisted the First Nation and the IESO with technical design aspects of the proposed project. The Whitesand project team continues to work towards a potential 2025/26 installation. In addition, Remotes is working with Neskantaga First Nation (Lansdowne House) and developers on a proposed large scale Biomass facility. Other projects initiated include a larger micro-grid solar installations at multiple road sites, but delays in securing provincial land have slowed the project. Hydroelectric development also continues to be of interest to many communities. Discussions with other parties on various projects are ongoing but are not concrete.

Effect on the DSP

Remotes will continue to actively work with proponents, but given it is a customer driven program Remotes' involvement is not fully developed at this time. Remotes would expect a role in design and technical review of project plans, with integration into existing systems as the core focus given that Remotes must ensure safe and reliable power, however any costs for Remotes involvement in renewable projects are paid for by the proponent of the project.

Given the stated Federal climate change goals Remotes anticipates increased interest in renewable projects going forward, particularly in those communities not connected to the Watay Project. However, currently there is little impact on the DSP other than ongoing OM&A costs necessary to support the REINDEER Program promotion and program activities, similar to its current form. In addition, there are currently no constraints on Remotes' distribution system that would prevent the connection of REG therefore Remotes does not anticipate any forecast capital costs to accommodate and connect REG facilities during the DSP plan period.

Although Remotes does not anticipate any system constraints or forecast capital costs associated with the known REG projects over the DSP plan period, Remotes continues to actively coordinate with the IESO on an as needed basis and has also provided the IESO with a letter outlining these details to ensure that IESO remains up to date. The IESO provided a comment letter upon completion of its review of the letter. Remotes' letter and the IESO response letter are included in Appendix G.

5.2.2.5 Regional Planning Process

The Regional Planning Process represents a coordinated, transparent, and cost-effective planning of electrical infrastructure at the regional level which was mandated by the OEB in 2013. To facilitate effective planning, the Province of Ontario is divided into 21 planning regions. As the lead transmitter, Hydro One Networks Inc. (HONI) conducts a Need Assessment and develops a Regional Infrastructure Plan that involves representatives from the IESO, and LDCs of the planning region.

Remotes is part of the "North of Dryden" sub-region which is part of the larger "Northwest Ontario Region", shown in Figure 5.2-10. The planning region includes the following participants involved in the scoping assessment and regional planning for the Northwest Ontario region:

- IESO
- HONI Transmission
- HONI Distribution
- Remotes

- Atikokan Hydro Inc.
- Fort Frances Power Corporation
- Sioux Lookout Hydro Inc.
- Synergy North

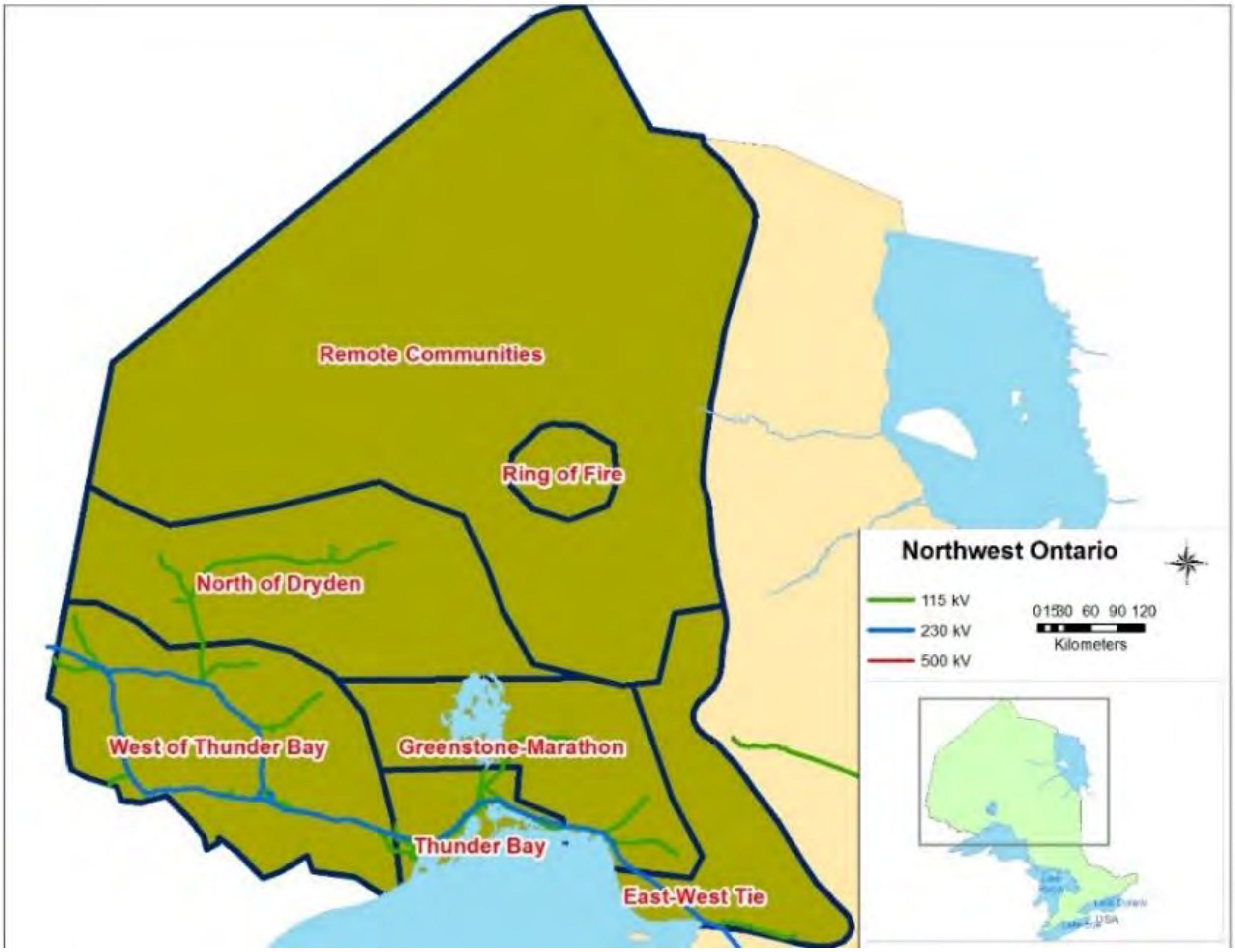


Figure 5.2-10: Northwest Ontario Region

The Northwest Ontario planning region is further divided into multiple sub-regions - Remote Communities, Ring of Fire, North of Dryden, West of Thunder Bay, Greenstone-Marathon, Thunder Bay and East-West Tie (depicted in Figure 5.2-11). Remotes is embedded within the North of Dryden Sub-region.

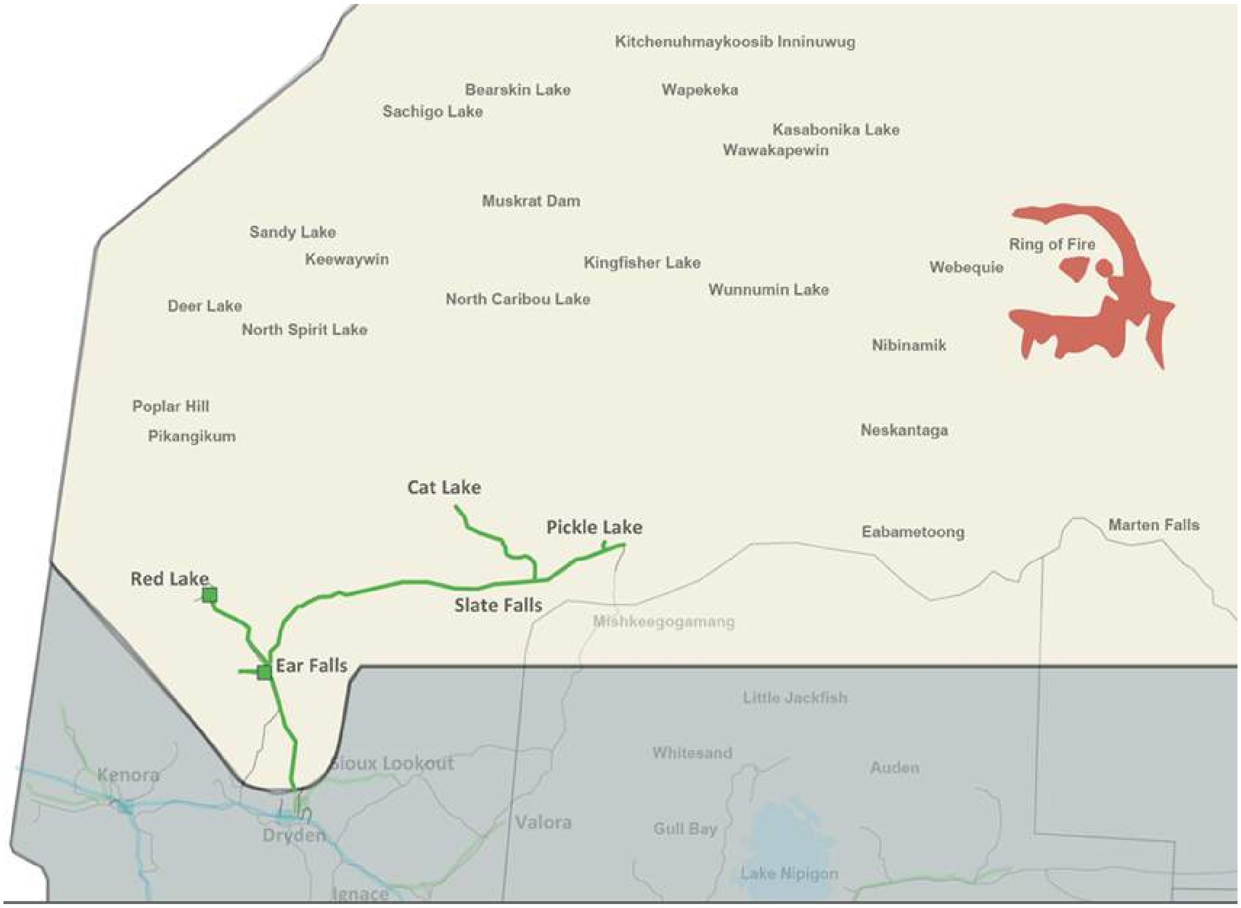


Figure 5.2-11: North of Dryden Sub-Region

The first regional planning cycle for the region was completed in June 2017 with the publishing of the Regional Infrastructure Plan (RIP) which identified needs and recommendations of preferred wired solutions for the medium-term timeframes. The key outcome of this planning process was the delineation of the Western Ontario region into four sub-regions each with their own Integrated Regional Resource Plan (IRRP). One key project that was developed in the North of Dryden region was the development of a single circuit 230 kV line to Pickle Lake. This project was supported in a 2016 letter from the IESO to the OEB outlining the recommended scope of the new line to Pickle Lake.

The second cycle of regional planning started in March 2020 with a Needs Assessment, which is in accordance with the Regional Planning process – that is the regional planning cycle should be revisited at least every five years. The Northwest Ontario Needs Assessment report was published by HONI in July 2020, which recommended that several initiatives required regional coordination. The outcomes of the Needs Assessment were put into the Scoping Assessment to determine the nature of the planning process. The Scoping Assessment was released by the IESO in January 2021, which identified the need for further coordination at the sub-regional level to develop an IRRP for each of the sub-regions. The development of the IRRP for the North of Dryden sub-region is now underway. Each step of the regional planning cycle is detailed further below.

5.2.2.5.1 Needs Assessment

A Needs Assessment (NA) was carried out by HONI for the Northwest Ontario region from March to July 2020. The purpose of the NA was to identify any new needs for the region as well as recommend a path forward for each need by either developing a preferred plan or identifying which needs require further assessment and/or regional coordination. Inputs considered for the NA included:

- Load forecast for all supply stations
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the region
- Insights from LDC representatives for the capacity needs, reliability needs, operational issues and major assets/facilities approaching end-of-life.

The report identified several needs in the region that may require further regional coordination and concluded that these needs should be reviewed further under the IESO-led Scoping Assessment process. One key need identified which directly impacts Remotes and the sub-region of North of Dryden is the need to provide capacity constraint relief to the Pickle Lake Switching Station.

Purpose: To identify any new needs and/or to reconfirm needs identified in the previous planning cycle that require regional coordination.

Participants: HONI, IESO, Synergy North, Fort Frances Power Corporation, Atikokan Hydro Inc., and Sioux Lookout Hydro Inc.

Status: Complete.

Deliverables: Needs Assessment Report issued by HONI on July 17, 2020 (see Appendix H).

5.2.2.5.2 Scoping Assessment

A Scoping Assessment (SA) Outcome Report was developed for the Northwest Ontario region in January 2021. The main outcome of the SA is the identification of the best planning approach for each need identified in the NA. The SA concluded that a single IRRP covering the entire region will be undertaken to address items within the area.

Although no specific needs were flagged for the North of Dryden Area, the SA noted that there have been significant system topology changes (Watay Project and remote connections) since the last regional planning cycle and that this area has a high concentration of mining developments which contribute to a high degree of uncertainty in load forecasts. As a result, the IRRP will include a refresh of previous studies to assess the capability of the existing system and study potential options to be triggered if future needs materialize.

Purpose: To further review the needs identified, in combination with information collected as part of the NA and information on potential wires and non-wires alternatives, to assess and determine the best planning approach for the whole or parts of the region.

Participants: IESO in collaboration with the Northwest Ontario regional participants.

Status: Complete.

Deliverables: Scoping Assessment Outcome Report issued by IESO on January 13, 2021 (see Appendix I).

5.2.2.5.3 Integrated Regional Resource Plan

The IESO formed a technical working group to plan and undertake the IRRP for the Northwest Ontario region to address the needs in the area. Identified needs related to the bulk transmission system supplying this region will be addressed in parallel with the IRRP process by the IESO, with results communicated to the Regional Participants.

There are key engagements identified in the terms of reference for completion of the IRRP for the Northwest Ontario region. Specifically, the process will consist of the following activities:

- Development of Stakeholder Engagement Plan.
- Development of updated 20-year demand/load forecast for the entire region.
- Assessment of the adequacy of transformer station ratings and load meeting capabilities.
- Assessment of options for confirmed needs.
- Development of long-term recommendations and implementation plan; and
- Completion of the IRRP report.

Purpose: To address the Needs identified in the January 2021 Scoping Assessment Report.

Participants: HONI, IESO, Atikokan Hydro Inc., Fort Frances Power Corporation, Sioux Lookout Hydro Inc., Synergy North, other transmitters and distributors as needed.

Status: In progress.

Deliverables: Integrated Regional Resource Plan (In progress; target issuance is mid-2022).

Effects on the DSP: The regional planning process has identified the requirement to complete the 230 kV system in the North of Dryden sub-region to provide relief to capacity constraints in the area. The IRRP will also include a refresh of the North of Dryden area system capability assessment. The activities completed as part of the IRRP could potentially lead to additional scopes of work specific to the North of Dryden sub-region, however these will not be known until completion of the IRRP.

5.2.2.6 Telecommunication Entities

Purpose of Engagement

The purpose of engagements with telecommunication entities is to facilitate the sharing of information and coordination of plans related to joint use agreements and broader telecommunication initiatives.

Engagement Initiation

Remotes typically initiates the engagements unless the telecommunication entities reach out to Remotes with specific requests.

Final Deliverables / Outcomes

Remotes has an established joint use program within its communities for other pole attachments such as cable, telephone, fibre, etc. The joint use program is supported by HONI through a service level agreement. Remotes has established joint use agreements in the majority of communities which set out the required design standards to ensure the safety of employees and the public. Unlike other utilities, Remotes do not charge fees to attach to poles, given the electrification agreements and land use considerations on First Nation lands.

Remotes' communities remain under-serviced for many telecommunication or alternative options that others in the province enjoy. There is currently a strong interest to improve telecommunications and other services in rural and northern parts of the province and when approached, Remotes will support these broader initiatives. Telecommunication discussions and consultations to date have been *very preliminary and of a logistical nature*.

Effect on the DSP

Given the preliminary nature of the consultations to date, the impacts to assets and future investments are not known at this time but are expected to only be of a minor nature. During the forecast period, Remotes expects a continued uptick of work in this area as well as technological advancement in the field.

5.2.2.7 CDM Related Engagements

Other than normal CDM program development, Remotes has not had any consultations that would have a significant impact on the DSP. Additional information on Remotes' CDM programs is included in Section 5.3.5.

5.2.3 Performance Measurement for Continuous Improvement

This section summarizes the objectives and measures that Remotes uses to monitor continuous improvement. Remotes' historical performance is noted, and any missed targets or objectives are explained along with any improvements implemented.

5.2.3.1 Distribution System Plan

As a result of the unique nature of Remotes' business, the set of performance metrics tracked by Remotes differ relative to those normally tracked by other LDCs. Remotes currently tracks three sets of performance metrics:

- **Custom Metrics set in the previous DSP filing:** In the last DSP filing, Remotes presented several custom performance metrics that were reflective of Remotes' business and operations at the time of filing. Remotes' historical performance relating to these metrics is included below, however several of these metrics will no longer be applicable in subsequent DSPs because of the impact of the Watay Project on Remotes' operations.
- **Internal Performance Metrics:** Remotes internal performance metrics are driven by its strategic goals. There are some similarities between Remotes' internal scorecards metrics and those included in the OEB performance scorecard, however different methods are used to derive these metrics and set targets to better reflect Remotes' unique operating characteristics (e.g., internal reliability metrics account for both generation and distribution, whereas the external OEB reliability metrics are distribution-specific). Internal metrics and targets evolve and change over time to appropriately reflect Remotes' operations and strategic objectives.
- **External Performance Metrics:** The external performance metrics are driven by external requirements and regulatory obligations, and include metrics as outlined in the OEB performance scorecards, the Distribution System Code (DSC) and the OEB's reporting and record keeping requirements (RRR). However, due to the unique nature of Remotes' business, Remotes is exempt from certain requirements that are not applicable to its operations.

Remotes is currently in the process of re-evaluating its custom and internal performance metrics as its traditional metrics may no longer align with Remotes' changing business and operations over the forecast period as grid connections occur for both existing and new communities in Remotes service territory. Revisions to Remotes performance metrics will be made once the Watay Project is completed and the full impacts of the project are better understood. Going forward, it is expected that Remotes will likely have a variety of measures for both off-grid and on-grid service, as the operating characteristics, Remotes' influence and risks are different under each scenario.

5.2.3.1.1 Custom Metrics set in Previous DSP Filing

Remotes measures performance and leads continuous improvement based on additional metrics encompassing asset/system operations performance and environmental stewardship.

5.2.3.1.1.1 Asset/System Operations Performance

Metrics based on asset/system operations performance provides a good measurement of Remotes' asset management strategy effectiveness. As such, Remotes identified several measures in its last DSP to assess asset/system operations performance in the categories of distribution losses, diesel generation efficiency, total generation efficiency, and generation availability.

<u>Distribution Loss</u>

Distribution losses are measured as the difference between the energy generated and energy sold, measured as a percentage of the total energy generated (all in kWh). The target for this metric is 3.6%

or less. Load losses for Remotes includes technical loss, non-technical loss such as theft, and internal diesel plant usage. This measure could be better defined as “system losses” as the internal generation usage represents largest portion of the loss with more traditional distribution loses being relatively insignificant given the micro distribution systems. This measure is also subject to billing cycle timing issues and is not generally an accurate measure given the independent, small electrical systems Remotes operate. As such, Remotes is planning to eliminate this metric from subsequent DSP requirements and reporting.

The distribution losses over the last five years are presented in the figure below. Remotes exceeded its target in all historical years except for 2021. Distribution losses were positively influenced by reduced internal diesel plant usage through CDM and the continued installation of newer more efficient technology and controls, but negatively impacted by the mix of units in-service, construction power usage and the increase of temporary generating units requiring electric heat. The missed target in 2021 was largely driven by increased construction power usage requirements.

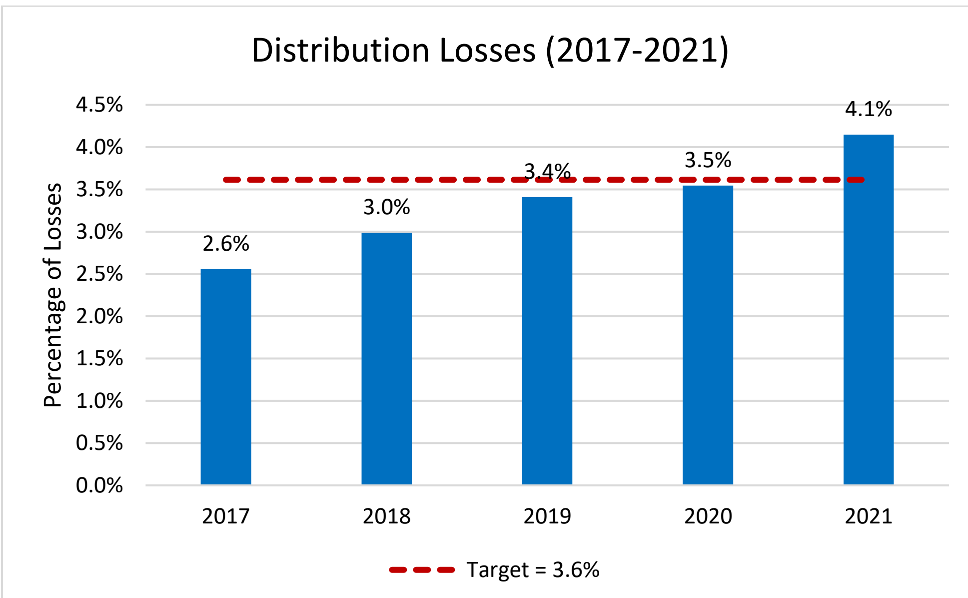


Figure 5.2-12: Annual Distribution Loss as a Percentage of Total Energy Generated

Remotes has not planned any material investments with distribution losses as the primary driver, however ongoing incremental distribution investments such as conductor restringing and distribution transformer replacements or internal diesel plant efficiency will help to reduce load loss.

<u>Diesel Generation Efficiency</u>

Remotes strives to maintain the efficiency of its diesel generation fleet through its procurement process, maintenance programs, and capital investment strategies. Diesel generation efficiency is measured as the amount of energy generated (in kWh) per litre of fuel consumed. The annual target for this metric is an average greater than or equal to 3.59 kWh per litre. As depicted in Figure 5.2-13, the diesel generation efficiency has trended incrementally upwards since 2018, and the target has been met since 2020. Diesel generation efficiency largely depends on the load profile in the community as optimized by the generator control scheme, the number of out-of-service units, and the fuel efficiency of the units themselves. In addition, when properly loaded, newer generating units generally continue to be slightly more efficient, as technology improves.

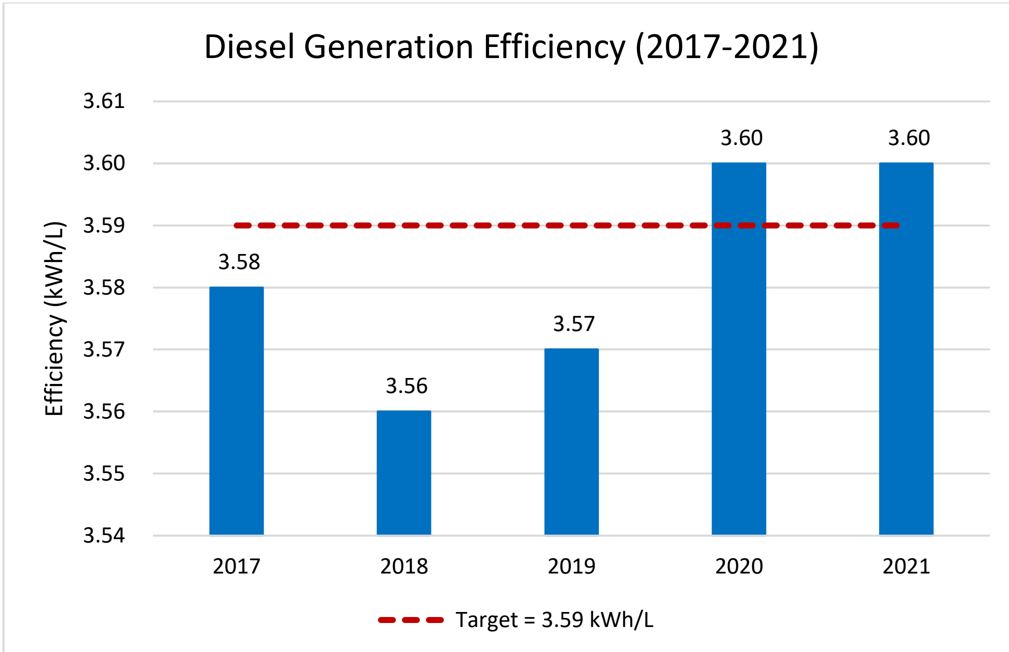


Figure 5.2-13: Annual Diesel Generation Efficiency (kWh/L)

To maintain the efficiency of its diesel generation fleet, Remotes continues to invest capital into generation replacements and overhauls. Generator replacements planned over the forecast period replace older, less efficient generators with newer, more efficient ones. Generator overhauls planned over the forecast period improve the efficiency of the refurbished units. While not a significant driver for the investment, generator upgrades have the same efficiency benefit as the replacement projects. The generator upgrades are contingent on ISC funding.

Significant gains in fuel efficiency were recognized over twenty years ago with the implementation of Supervisory Control and Data Acquisition (SCADA) and Programable Logic Controller (PLC) systems, but since then only minor incremental efficiency gains have been possible. Given the significant change in use of the majority of diesel assets after the Watay grid connection and given the limited incremental efficiency gains that are expected to be possible in future years, Remotes is planning to eliminate this metric from subsequent DSP requirements and reporting.

Percentage of Energy Generated by using Renewables

By investing in non-diesel generation assets, such as solar, hydroelectric, and grid connections, Remotes can reduce its reliance on diesel fuel, which is important to Remotes' customers.

The percentage of energy generated using renewables is calculated by dividing the kWh generated from solar and hydroelectric sources by the total kWh of energy generated by Remotes. The set target of 2.41% or greater is based on the historical period average.

Remotes currently operates two hydroelectric stations, and there are 18 customer-owned solar installations in service. Figure 5.2-14 depicts the percentage of energy generated from renewables for the years 2017 through 2021. The amount of energy generated each year fluctuates based on the demand in the community. The percentage of energy generated from renewables also depends on the condition of the generating units and available water resource for the hydroelectric units. The drop in 2021 is largely due to less energy generated from the Deer Lake hydroelectric generators as a result of dry conditions (i.e., water availability limitations) and the evacuation of the community for over three weeks during the summer fire season during which the Deer Lake hydroelectric units were not generating any power.

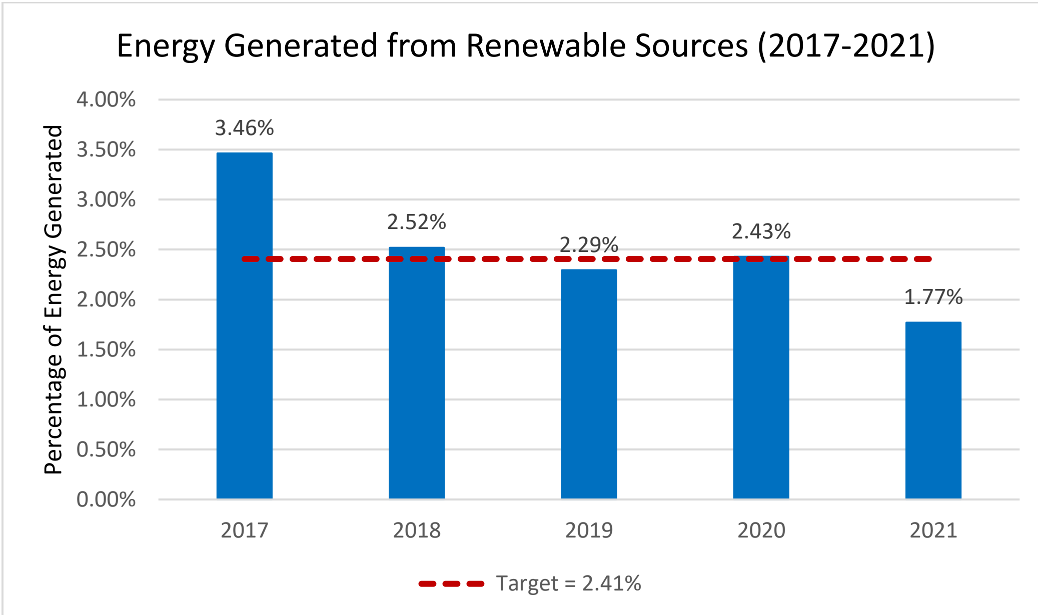


Figure 5.2-14: Percentage of Energy Generated from Renewable Sources

There are no capital investments into the existing renewable generation planned over the forecast period. Remotes will continue to maintain its renewable assets to ensure its reliable operation. Given pending grid connection with Watay, the long-term use of the Deer Lake hydroelectric station is also unknown at this time, but there is interest by both the First Nation and Remotes to continue to operate if a creative solution can be found.

Given the significant change in use of the majority of diesel asset, and respective renewable assets after grid connection, Remotes is planning to eliminate this metric from subsequent DSP requirements and reporting.

Generator Availability

Generation availability is an indicator of the success of Remotes' capital and maintenance programs and provides an indicator for power reliability. Generation availability is calculated annually using the total duration of unplanned outages over the year, where the number of hours of unplanned outages is subtracted from the number of hours in the year, as a percentage of the total number of hours in the year. The methodology looks at all outages under OEB Cause Code 2 that are 1 minute or greater. Based on historical period average, Remotes has an annual target of 99.93% or greater for this metric. As seen in Table 5.2-8 and Figure 5.2-15, Remotes has been able to meet and exceed this target continuously.

Table 5.2-8: Annual Percentage of Generation Availability

Metric	2017	2018	2019	2020	2021
Total minutes per year	9,986,400	9,986,400	9,986,400	10,013,760	9,986,400
Total outage duration minutes per year in Cause Code 2, excluding outages <1 minute	9,982,547	9,982,806	9,984,504	10,009,123	9,982,935
Generation Availability	99.96%	99.96%	99.98%	99.95%	99.97%

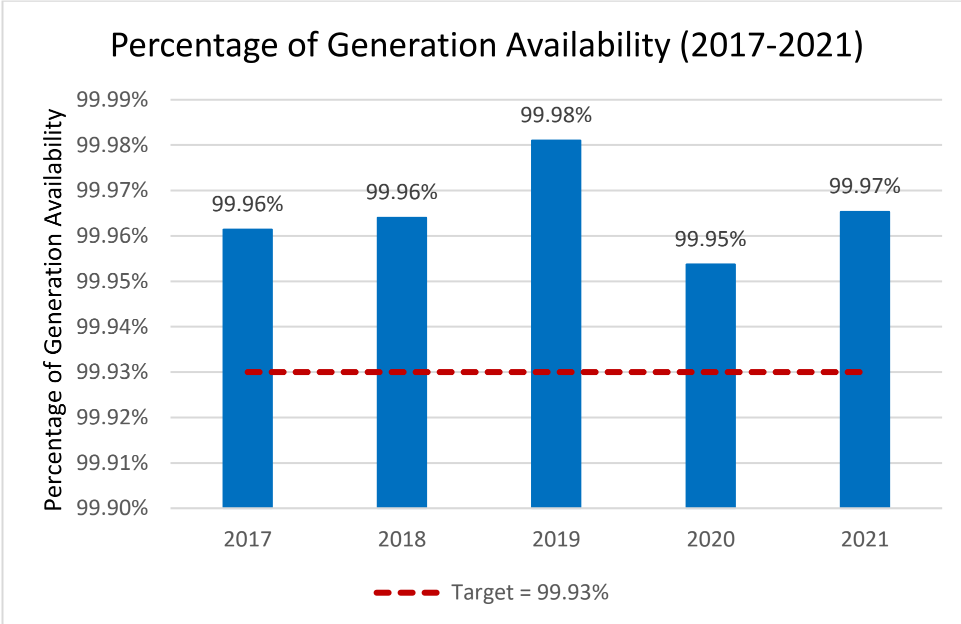


Figure 5.2-15: Annual Percentage of Generation Availability

Similar to system reliability, generation availability drives investment into generation assets. Capital investment into Remotes' generation fleet, through planned replacements and overhauls, addresses generator availability. Generation upgrade projects also improve generation availability, since an older generator is replaced with a newer one and the decommissioned generator can be salvaged for spare parts to enable faster emergency repair times. Remotes' rigorous asset management program includes preventive maintenance on generators, which will reduce generator downtime.

It should be noted that Remotes also tracks generation availability internally using a slightly different methodology (detailed further in Section 5.2.3.1.2 below). Since the internal generation availability metric more appropriately reflects Remotes' operations, the external generation availability metric detailed above will be replaced by Remotes' internal generation availability metric going forward.

5.2.3.1.1.2 Environmental Stewardship

Since environmental stewardship is important to Remotes' customers, Remotes tracks an additional category of measures related to greenhouse gas emissions.

Greenhouse Gas Emissions

Since diesel fuel is currently the most reliable and cost-effective generation method for remote communities, most of Remotes' electricity is generated using diesel. Remotes is cognisant of the greenhouse gas contributions of its fleet and, therefore, monitors its emissions.

57 generators within the 19 diesel generating stations burn diesel fuel to produce electricity, directly emitting greenhouse gases to the atmosphere.

The metrics tracked by Remotes in relation to greenhouse gas emissions are:

- Emission of carbon dioxide equivalents (CO_2e) measured in tonnes.
- Net emission intensity (tonnes of CO_2e per kWh of total energy generated).

Figure 5.2-16 shows the annual greenhouse gas (GHG) emissions produced from the generators in tonnes of CO_2e. Figure 5.2-17 shows the CO_2e generated in comparison to the variable target set every year over the historical period. The emission intensity has trended upward for the past few years but is still below the target. This is due to less energy generated from renewable sources and upward load pressure impacting emission intensity. However, the long-term trend in Figure 5.2-18 shows that significant improvements have been made to reduce emissions, but continued innovation is required for further reduction.

Remotes has invested in renewable generation and is working with many local communities and their partners on renewable projects to help meet their electricity needs. Improvements in diesel generator technology will also improve the net emission intensity. As Remotes replaces older generators with newer ones through its replacement and upgrade programs and overhauls generators, it is expected that the net emission intensity will also decrease. In addition, following the connection of multiple communities to the Watay transmission grid, emissions will be reduced significantly since the diesel generators within the grid-connected communities will be used for backup purposes only.

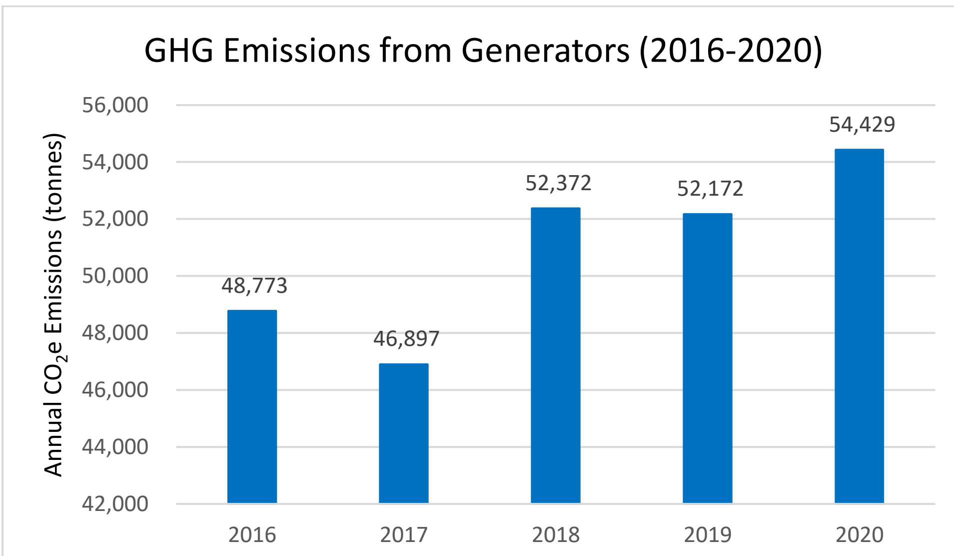


Figure 5.2-16: Annual Greenhouse Gas (GHG) Emissions from Generators (tonnes)

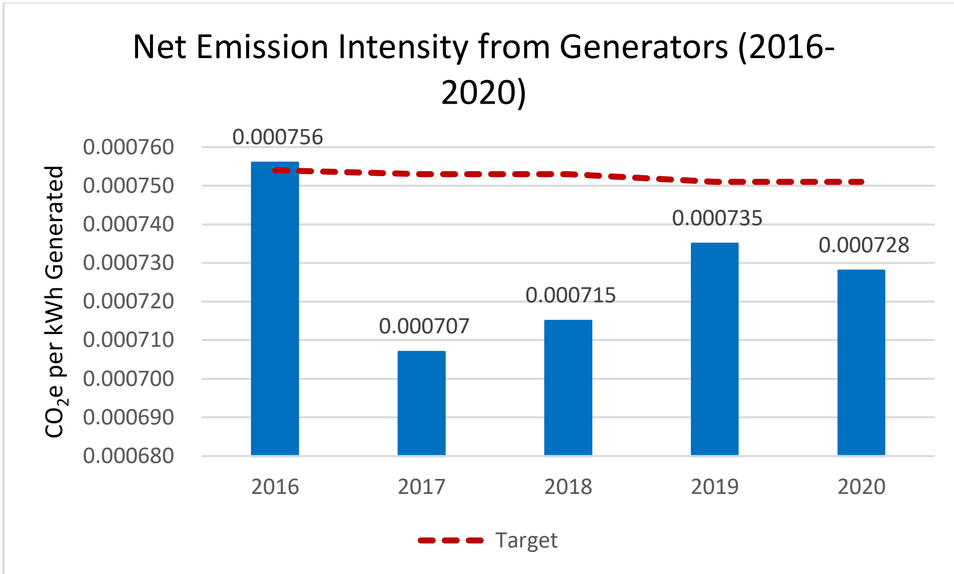


Figure 5.2-17: Emission Intensity from Generators (CO2e/kWh)

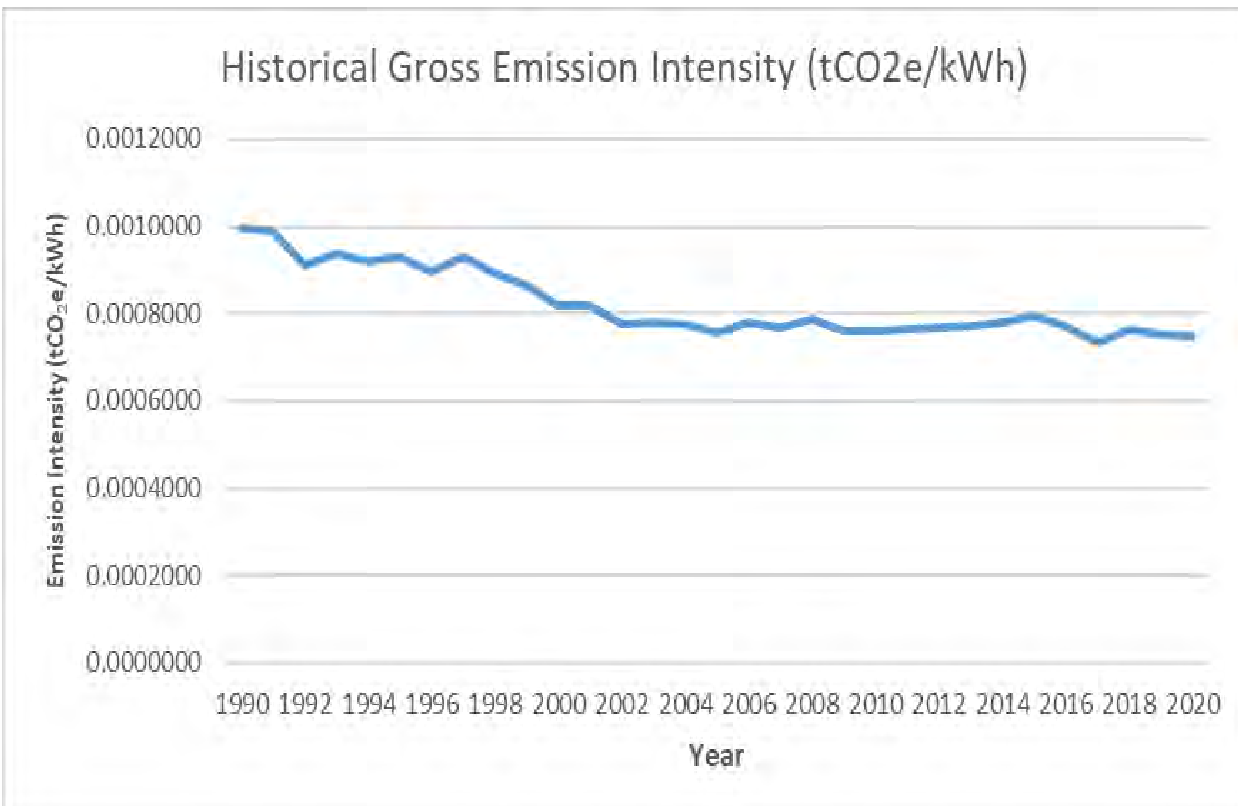


Figure 5.2-18: Tonnes of CO2e Emitted per kWh Generated (1990-2020)

5.2.3.1.2 Internal Performance Metrics

Similar to most businesses, Remotes uses a performance scorecard system to monitor, measure and drive performance. Internal scorecards and their respective targets are developed annually and align with the stated strategic goals of the organization. Remotes' internal performance measures are divided into the following general categories:

- **Health & Safety**: Remotes strives for an injury free workplace. Under this category, targets are set to drive performance for common health and safety metrics including lost time injuries, serious injuries, recordable injuries and incidents, near miss/safety catches, high Maximum Reasonable Potential for Harm (MRPH) incidents and number of completed Health and Safety Management System (HSMS) objectives and achievements.
- **Customer Relations**: Remotes strives to inspire customer loyalty and improve community relationships. Remotes has historically measured its performance under this category by means of customer satisfaction results, number of Director's FN/Tribal Council Meetings and number of Customer & Community Outreach Initiatives.
- **Operational Excellence**: Remotes strives to maintain/improve system reliability. Reliability performance is determined using SAIDI, SAIFI and generator availability metrics.
- **Productivity**: Remotes strives to improve efficiency of operations. Over the historical period, the metrics recorded under this category have varied from year to year depending on key projects and initiatives that were underway at the time the internal scorecards were developed. Under this category, performance tends to be measured by the number of milestones, deliverables and/or work that is completed on time and on budget.
- **Environmental Stewardship**: Remotes strives to protect the environment. The metrics under this category are primarily related to the generation side of Remotes' business and include the number of spills, number of litres lost to the environment, and number of completed Environmental and Management System (EMS) objectives and achievements under the ISO 14001 framework.

For Remotes, the internal scorecard is the best representation of overall performance. The standard OEB scorecard does not fully align with Remotes' unique operating characteristics and therefore multiple exemptions exist. The internal scorecard and metrics are presented during the first quarter, annually to the Remotes Board of Directors for approval. Ranges on desired performance are generally based on past performance and continuous improvement. Many identical or similar metrics are carried over from year-to-year with only slight changes to definitions or criteria. Other metrics are added or dropped, depending on broader corporate initiatives, key projects as well as desired initiatives or improvements. Remotes has had an established internal scorecard system in place for decades and fully expects to continue to utilize it its benefits.

Remotes' internal performance scorecard results for the last five historical years are summarized in Table 5.2-10 and the legend for the various symbols is provided in Table 5.2-9. Detailed historical annual performance results are provided in Table 5.2-11 through Table 5.2-15, and any missed targets or objectives are explained.

Table 5.2-9: Internal Performance Scorecard - Legend

Symbol	Definition
◆	Below Threshold
■	Below Target
●	Target Met
★	Exceeds Target

Table 5.2-10: Remotes Internal Performance Scorecard – Historical Results

Strategic Objective		Performance Measure	Historical Performance Results				
			2017	2018	2019	2020	2021
Health & Safety	Injury Free Workplace	Lost Time Injury	●	●	●		
		Total Recordable Injury	●	★	●	●	
		Recordable Incidents					●
		Serious Injury				●	●
		High MRPH Incidents	★	★	●		
		Near Miss/Safety Catch				★	★
		HSMS Objectives and Achievements	●	★	★	★	★
Customer Relations	Inspire Customer Loyalty and Improve Community Relationships	Customer Satisfaction Survey Results	●				
		Director's FN/Tribal Council Meetings	★	★			
		Customer & Community Outreach Initiatives	◆	◆	★	●	★
Operational Excellence	Maintain/ Improve System Reliability	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point	★	★	★	◆	◆
		System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point	★	★	★	●	■
		Generation Availability	●	●	●	◆	■
Productivity	Improve Efficiency of Operations	Kingfisher Upgrade Milestones	●				
		Marten Falls Project Milestones		●			
		Wapekeka Project Milestones			◆		
		Marten Falls Project Execution					★
		Design & Planning				■	●
		Fuel Management Improvements				●	
		Generation Major Maintenance					★
Business Excellence	Financial Strength	Distribution System Plan & Cost of Service Filing Milestones	★				
		Fuel Management Improvements		●	★		
Environmental Stewardship	Environmental Protection	Litres lost to the Environment	●	◆	◆	★	★
		Hydro One Spills	◆	◆	●	★	★
		Category A Spills/Significant Spills over 100L	●	●	●	●	★
		EMS Objectives and Achievements	★	★	●	★	■

Table 5.2-11: Internal Performance Scorecard - 2017 Results

Strategic Objective		Performance Measure	Actual	Target	Result	Notes on Missed Targets
Health & Safety	Injury Free Workplace	Lost Time Injury	0	0	●	
		Total Recordable Injury	2	≤2	●	
		High MRPH Incidents	0	≤1	★	
		HSMS Objectives and Achievements	25	24	●	
Customer Relations	Inspire Customer Loyalty and Improve Community Relationships	Customer Satisfaction Survey Results	90%	≥ 90%	●	
		Director's FN/Tribal Council Meetings	18	4	★	
		Customer & Community Outreach Initiatives	18	21	◆	Unplanned work on other customer initiatives (Fair Hydro Plan, New Bill Project and the Big Trout Lake-Wapekeka Tie Line)
Operational Excellence	Maintain/Improve System Reliability	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point	10.13	11.24	★	
		System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point	11.74	12.97	★	
		Generation Availability	99.5%	99.4%	●	
Productivity	Improve Efficiency of Operations	Kingfisher Upgrade Milestones (on time, on budget)	13	13	●	
Business Excellence	Financial Strength	Distribution System Plan & Cost of Service Filing Milestones	23	23	★	
Environmental Stewardship	Environmental Protection	Litres lost to the Environment	0	≤100	●	
		Hydro One Spills	7	≤6	◆	Increase in glycol spills related to generation equipment failure and have occurred inside the DGS.
		Category A Spills	0	0	●	
		EMS Objectives and Achievements	42	34	★	

Table 5.2-12: Internal Performance Scorecard - 2018 Results

Strategic Objective		Performance Measure	Actual	Target	Result	Notes on Missed Targets
Health & Safety	Injury Free Workplace	Lost Time Injury	0	0	●	
		Total Recordable Injury	0	≤2	★	
		High MRPH Incidents	0	≤1	★	
		HSMS Objectives and Achievements	41	40	★	
Customer Relations	Inspire Customer Loyalty and Improve Community Relationships	Director's FN/Tribal Council Meetings	9	8	★	
		Customer & Community Outreach Initiatives	10	13	◆	Staff resources were focused on work related Big Trout-Wapekeka Tie-Line and Pikangikum Integration.
Operational Excellence	Maintain/Improve System Reliability	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point	5.97	11.23	★	
		System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point	8.71	13.28	★	
		Generation Availability	99.3%	99.5%	●	
Productivity	Improve Efficiency of Operations	Marten Falls Project Milestones (on time, on budget)	8	8	●	
Business Excellence	Financial Strength	Fuel Management Improvements	23	23	●	
Environmental Stewardship	Environmental Protection	Litres lost to the Environment	418	≤100	◆	A spill in Biscotasing leaked diesel fuel to the environment and remains hard to access.
		Hydro One Spills	15	6	◆	Higher than planned as a result of multiple glycol related spills from generating equipment failures. A hose assessment and replacement program is now in place.
		Category A Spills	0	0	●	
		EMS Objectives and Achievements	23	20	★	

Table 5.2-13: Internal Performance Scorecard - 2019 Results

Strategic Objective		Performance Measure	Actual	Target	Result	Notes on Missed Targets
Health & Safety	Injury Free Workplace	Lost Time Injury	0	0	●	
Health & Safety	Injury Free Workplace	Total Recordable Injury	0	≤2	●	
Health & Safety	Injury Free Workplace	High MRPH Incidents	0	≤1	●	
Health & Safety	Injury Free Workplace	HSMS Objectives and Achievements	33	30	★	
Customer Relations	Inspire Customer Loyalty and Improve Community Relationships	Customer & Community Outreach Initiatives	30	26	★	
Operational Excellence	Maintain/Improve System Reliability	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point	7.22	10.51	★	
Operational Excellence	Maintain/Improve System Reliability	System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point	8.01	10.69	★	
Operational Excellence	Maintain/Improve System Reliability	Generation Availability	99.6%	99.5%	●	
Productivity	Improve Efficiency of Operations	Wapekeka Project Milestones (on time, on budget)	4	6	◆	Work on the Wapekeka Upgrade project was stopped as a result of accumulating project arrears.
Business Excellence	Financial Strength	Fuel Management Improvements	27	25	★	
Environmental Stewardship	Environmental Protection	Litres lost to the Environment	1,042	≤100	◆	A spill in Wapekeka leaked diesel fuel to the environment and remains hard to access.
Environmental Stewardship	Environmental Protection	Hydro One Spills	11	11	●	
Environmental Stewardship	Environmental Protection	Category A Spills	0	0	●	
Environmental Stewardship	Environmental Protection	EMS Objectives and Achievements	17	16	●	

Table 5.2-14: Internal Performance Scorecard - 2020 Results

Strategic Objective		Performance Measure	Actual	Target	Result	Notes on Missed Targets
Health & Safety	Injury Free Workplace	Serious Injury	0	0	●	
		Total Recordable Injury	1	1	●	
		Near Miss/Safety Catch	62	40	★	
		HSMS Objectives and Achievements	32	28	★	
Customer Relations	Inspire Customer Loyalty and Improve Community Relationships	Customer & Community Outreach Initiatives	37	38	●	
Operational Excellence	Maintain/Improve System Reliability	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point	9.76	7.69	◆	Higher than plan due to increased distribution planned outages, defective distribution equipment and foreign interference.
		System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point	9.42	9.40	●	
		Generation Availability	99.1%	99.5%	◆	Remotes' normal generation redundancy was compromised on two separate occasions when Remotes had units out of service and experienced a failure on a second genset causing multiple and prolonged outages in the community of Sandy Lake in February and in Big Trout Lake during the month of April.
Productivity	Improve Efficiency of Operations	Project Design and Planning	56	65	■	Certain larger project milestones were completed on a delayed schedule and did not meet the intended target date due to increased project complexity
		Fuel Management Improvements	25	25	●	
Environmental Stewardship	Environmental Protection	Litres lost to the Environment	0	100	★	
		Hydro One Spills	6	10	★	
		Category A Spills	0	0	●	
		EMS Objectives and Achievements	27	23	★	

Table 5.2-15: Internal Performance Scorecard - 2021 Results

Strategic Objective		Performance Measure	Actual	Target	Result	Notes on Missed Targets
Health & Safety	Injury Free Workplace	Serious Injuries	0	0	●	
		Recordable Incidents	1	1	●	
		Near Miss/Safety Catches	71	46	★	
		HSMS Objectives and Achievements	20	18	★	
Customer Relations	Inspire Customer Loyalty and Improve Community Relationships	Customer & Community Outreach Initiatives	34	31	★	
Operational Excellence	Maintain/Improve System Reliability	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point	8.90	7.66	◆	Higher Dx outages and tree contacts, partially offset by decreased foreign interference and generation unplanned outages.
		System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point	8.97	8.71	■	Higher generation planned outages and distribution unplanned outages.
		Generation Availability	99.3%	99.4%	■	Impacted by higher generation planned outages.
Productivity	Improve Efficiency of Operations	Design & Planning	355	346	●	
		Marten Falls Project Execution	48	42	★	
		Generation Major Maintenance	16	14	★	
Environmental Stewardship	Environmental Protection	Litres lost to the Environment	0	100	★	
		Number of Spills	5	10	★	
		Category A Spills	0	1	★	
		EMS Objectives and Achievements	29	30	■	Due to other work priorities specific OTAPs were deferred to 2022.

5.2.3.1.3 External Performance Metrics

As noted above, external performance metrics are driven by external requirements and regulatory obligations, and include metrics as outlined in the OEB performance scorecards, the DSC and the OEB's RRR. However, due to the unique nature of Remotes' business, Remotes is exempt from certain requirements that are not applicable to its operations.

A summary of Remotes' historical performance as presented in the OEB Performance Scorecards is presented in Table 5.2-16. Those metrics which are not applicable to Remotes are noted as "n/a".

Table 5.2-16: DSP Performance Measures

Performance Outcome	Measure	Metric	2017	2018	2019	2020	2021	Target[1]
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	90.59%	95.33%	100.00%	100.00%	100.00%	90.00%
		Scheduled Appointments Met on Time	n/a	n/a	n/a	n/a	n/a	90.00%
		Telephone Calls Answered on Time	100.00%	100.00%	100.00%	100.00%	100.00%	65.00%
	Customer Satisfaction	First Contact Resolution	100.00%	100.00%	100.00%	100.00%	100.00%	No target
		Billing Accuracy	97.89%	97.90%	96.88%	94.28%	89.35%	98.00%
		Customer Satisfaction Survey	90.0%	90.0%	93.0%	93.0%	96.0%	No target
Operational Effectiveness	Safety	Level of Public Awareness	70.40%	70.40%	72.38%	72.38%	73.93%	No target
		Level of Compliance with Ontario Regulation 22/04	NI	C	C	C	C	C
		Number of General Public Incidents	0	0	0	0	0	0
		Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	0.000
	System Reliability	Ave. Number of Times that Power to a Customer is Interrupted	3.98	2.02	3.69	3.42	3.33	4.18
		Ave. Number of Hours that Power to a Customer is Interrupted	7.55	4.94	6.58	8.27	6.72	7.40
	Asset Management	Distribution System Plan Implementation Progress	83%	100%	98%	108%	88%	No target
	Cost Control	Efficiency Assessment	n/a	n/a	n/a	n/a	n/a	No target
		Total Cost per Customer	n/a	n/a	n/a	n/a	n/a	No target
		Total Cost per km of Line	n/a	n/a	n/a	n/a	n/a	No target
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation CIA Completed on Time	n/a	n/a	100.00%	n/a	n/a	No target
		New Micro-embedded Generation Facilities Connected on Time	n/a	n/a	n/a	n/a	n/a	90%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	1.80	1.00	0.98	1.02	0.75	No target
		Leverage: Total Debt (short-term & long-term) to Equity Ratio	n/a	n/a	n/a	n/a	n/a	No target
		Regulatory ROE – Deemed (included in rates)	n/a	n/a	n/a	n/a	n/a	No target
		Regulatory ROE - Achieved	n/a	n/a	n/a	n/a	n/a	No target

[1] Targets shown are for year 2021.

A review of Remotes' historical performance above indicates that Remotes has largely met or exceeded expectations over the historical period, with the following exceptions:

- **Billing Accuracy:** Over the historical period, Remotes has not met the industry standard of 98%. This is largely because Remotes has not installed a smart meter network due to limited communications infrastructure in its service territory and therefore relies on manual readings. Manual readings are more likely to result in higher planned and unplanned estimates. Remotes generally contracts with local community members to read the meters. Readings are then faxed to the office and entered into the system by the billing team. If the faxed readings are late or not performed, they result in an unplanned estimate. In 2016, Remotes also implemented quarterly meter readings for seasonal customers to reduce the planned estimates for those customers, but there are a number of seasonal customers whose meters are inaccessible at certain times of the year, usually winter, making the industry standard difficult to attain. There are no planned investments during the DSP plan period related to improving performance under this metric, however Remotes will continue to do what it can to provide customers with accurate bills.

- **Level of Compliance with Ontario Regulation 22/04:** In 2017, Remotes was assessed by the ESA as Needs Improvement (NI) in compliance with Ontario Regulation 22/04. A third-party application was found to have inadequate documentation. During 2017, Remotes developed an enhanced process for joint use attachment which requires greater detail in the application coupled with improved timelines for compliance. Remotes has maintained a "Compliant" rating ever since. There are no planned material investments or changes expected during the DSP plan period related to this requirement.

- **Average Number of Hours that Power to a Customer in Interrupted:** In 2017, the number of planned outages was high as a result of Remotes conducting planned equipment replacements and making improvements to the distribution system. For 2020, Remotes reported an average outage duration of 8.3 hours, which is 1.7 hours worse than 2019 (6.6) and 0.9 hours worse than the OEB target of 7.4. This was due to outages caused by an increase in tree contacts and adverse weather.

5.2.3.1.3.1 Service Quality and Reliability

Remotes external service quality and reliability performance is detailed further in the following subsections. Service quality and reliability indicators can also be found in Appendix 2-G of this COS Application.

Service Quality Requirements

Remotes sets a high standard for performance when it comes to customer care. Remotes strives to deliver customer excellence and value through the execution of its investments and operations. In accordance with Chapter 7 of the OEB's DSC, Remotes tracks and reports on Service Quality Requirements (SQR), however, due to the unique nature of Remotes' business, Remotes is exempt from certain requirements that are not applicable to its operations. Exemptions include:

- High Voltage Connections: This requirement does not apply as Remotes does not have high voltage connections.

- Appointment Scheduling, Appointments Met, and Rescheduling a Missed Appointment: Remotes does not make appointments with customers. Due to the inaccessibility of its service territory, work is bundled and performed when a crew is in the community.
- Telephone Call Abandon Rate: Call Abandon Rate does not apply since Remotes does not have an Interactive Voice Response (IVR).
- Emergency Urban Response: Remotes is exempt from this requirement as Remotes does not have urban response.

Remotes' SQR performance for the historical period is summarized in Table 5.2-17. Explanations for any material changes, missed targets or declining trends, and whether and how the DSP addresses these issues, is detailed below.

Table 5.2-17: Historical Service Quality Metrics

Service Quality Metric	2017	2018	2019	2020	2021	Minimum Standards
Low Voltage Connections[1]	90.59%	95.33%	100.00%	100.00%	100.00%	> 90%
High Voltage Connections	n/a	n/a	n/a	n/a	n/a	> 90%
Telephone accessibility	100.00%	100.00%	100.00%	100.00%	100.00%	> 65%
Appointments met	n/a	n/a	n/a	n/a	n/a	> 90%
Written response to enquiries	100.00%	100.00%	100.00%	100.00%	100.00%	> 80%
Emergency Urban Response	n/a	n/a	n/a	n/a	n/a	> 80%
Emergency Rural Response	98.83%	98.44%	98.95%	99.56%	99.23%	> 80%
Telephone call abandon rate	n/a	n/a	n/a	n/a	n/a	< 10%
Appointment scheduling	n/a	n/a	n/a	n/a	n/a	> 90%
Rescheduling a Missed Appointment	n/a	n/a	n/a	n/a	n/a	> 100%
Reconnection Performance Standard	89.09%	93.33%	95.24%	0.00%	100.00%	> 85%
New Micro-embedded Generation Facilities Connected	n/a	n/a	n/a	n/a	n/a	> 90%
Billing Accuracy	97.89%	97.90%	96.88%	94.28%	89.35%	> 98%

[1] Connection of new services low voltage does not include connection of micro-embedded generation facilities.

Material changes in indicators include reconnection performance standard and meter reads. Reconnections were not completed in 2020 because of COVID-19 as collection trips were deferred. Remotes expects many metrics will revert to pre-pandemic performance in the DSP plan period, once the pandemic is over. Meter reading billing accuracy was also negatively impacted by COVID-19 and is expected to revert to pre-pandemic levels as well. Remotes will continue to work with the communities on meter reading efficiency and backup plans.

<u>Reliability Requirements</u>

Remotes is small business with a limited customer count who operate in standalone integrated generation and distribution systems. As such, reliability statistics and measures are very granular in nature and subject to volatility. Individual community results can vary significantly.

System reliability is overseen by the Remotes Outage Committee (ROC), which was established in 2012. The ROC comprised of a representative from every major operating function, meets monthly to focus on both preventing outages before they occur through system investments, as well as ensuring trouble response is done safely and efficiently. The group also examines all future planned maintenance outages to allow work to be coordinated between the different departments where possible to reduce the number of planned outages in a community. Given sole generation and immediate direct impacts to overall customer reliability, much of the emphasis is ensuring that all generating units are in full operational service. Some noted improvements have included outage reporting and outage response, operator training, emergency preparedness response plans (EPRP) enhancements, and customer notification. Most importantly, the ROC has created a forum to discuss both short- and longer-term system investments for both distribution and generation assets. Some noted improvements include emergency failure response, bird protection, engine replacements, PLC and SCADA improvements, defective equipment programs, as well as system monitoring and automation.

The key metrics that Remotes tracks to measure reliability are the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI). SAIDI, SAIFI and CAIDI are measured under four scenarios:

1. By including all power interruptions
2. By excluding interruptions due to Loss of Supply (LOS)
3. By excluding interruptions due to Major Event Days (MED)
4. By excluding interruptions due to LOS and MED

The fixed performance baseline targets for distribution SAIDI and SAIFI over the historical period is based on the average performance over the 2013-2017 period, excluding LOS and MED. This corresponds to a fixed target of 7.40 for SAIDI and 4.18 for SAIFI. No targets are set for CAIDI.

Remotes' reliability metric values for the historical period are shown in the tables and figures below. The adjusted SAIDI, SAIFI and CAIDI trending is relatively flat over the last five historical years.

Table 5.2-18: Historical Reliability Performance Metrics – All Cause Codes

Metric	2017	2018	2019	2020	2021	Average
SAIDI	10.25	9.48	12.19	15.06	11.28	11.65
SAIFI	11.92	8.98	8.51	9.67	9.25	9.67
CAIDI	0.86	1.06	1.43	1.56	1.22	1.22

Table 5.2-19: Historical Reliability Performance Metrics – LOS and MED Adjusted

Metric	2017	2018	2019	2020	2021	Average	2021 Target
Loss of Supply Adjusted							
SAIDI	7.55	4.94	9.85	8.27	6.73	7.47	-
SAIFI	3.98	2.02	3.84	3.42	3.33	3.32	-
CAIDI	1.90	2.45	2.57	2.42	2.02	2.27	-
Major Event Days Adjusted							
SAIDI	10.25	9.48	8.86	15.06	11.28	10.99	-
SAIFI	11.92	8.98	8.35	9.67	9.25	9.64	-
CAIDI	0.86	1.06	1.06	1.56	1.22	1.15	-
Loss of Supply and Major Event Days Adjusted							
SAIDI	7.55	4.94	6.58	8.27	6.73	6.81	7.40
SAIFI	3.98	2.02	3.69	3.42	3.33	3.29	4.18
CAIDI	1.90	2.45	1.78	2.42	2.02	2.11	-

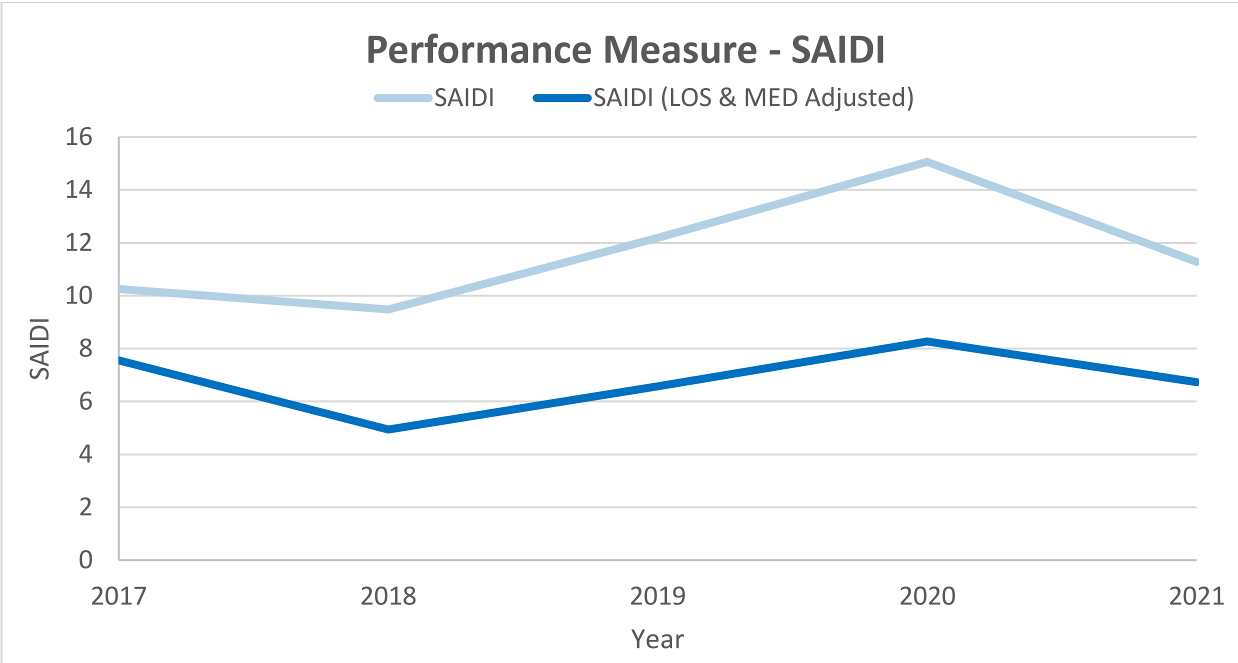


Figure 5.2-19: Performance Measure - SAIDI

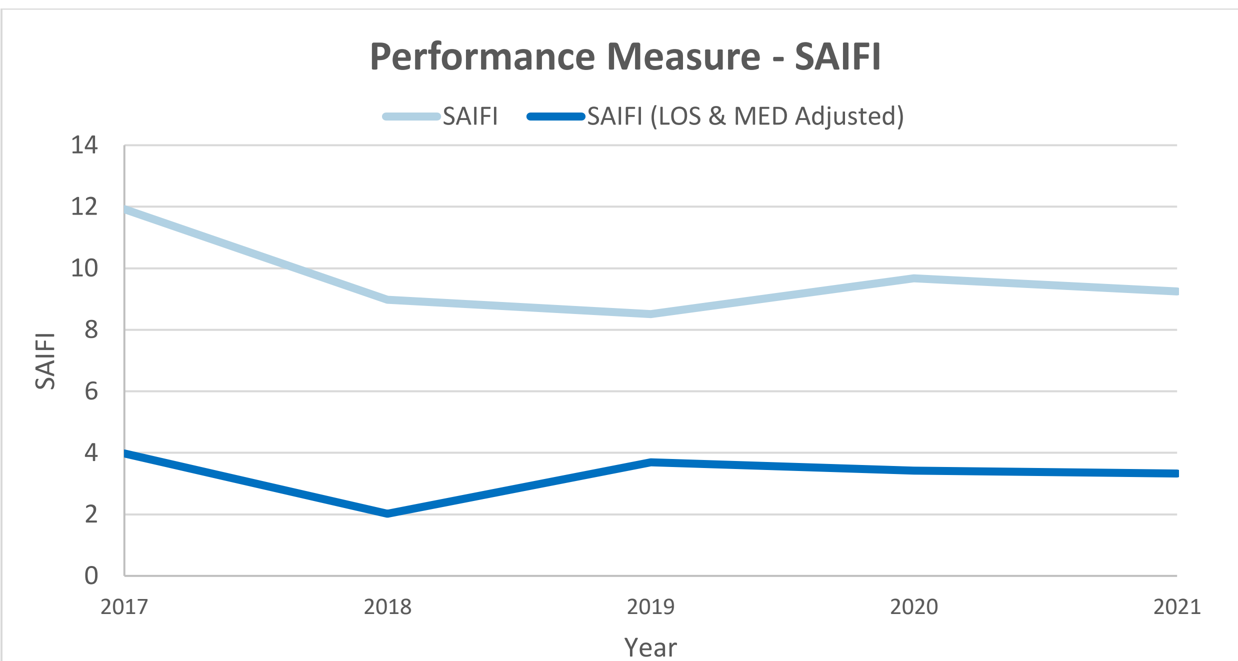


Figure 5.2-20: Performance Measure - SAIFI

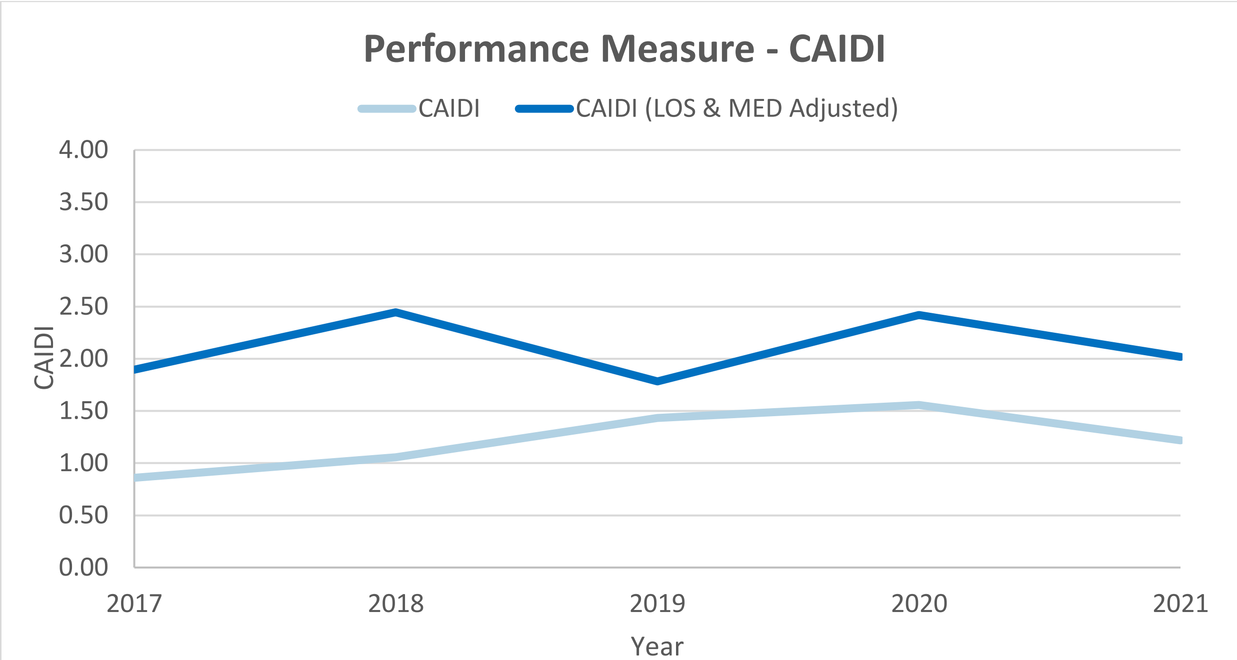


Figure 5.2-21: Performance Measure - CAIDI

In 2017, the number of planned outages was high as a result of Remotes conducting planned equipment replacements and making improvements to the distribution system. These planned outages were the driving cause for the missed SAIDI and SAIFI targets in 2017. The missed SAIDI target in 2020 was due to outages caused by an increase in tree contacts and adverse weather.

5.2.3.1.3.2 Outage Details for Years 2017-2021

Outages details for the 2017-2021 period, including a summary of Major Events and breakdowns of outages experienced by cause code are provided in the following sub-sections.

<u>Major Events</u>

During the historical period, Remotes only experienced one major event.

On September 20th and 21st of 2019, an extreme windstorm passed through the Red Lake Region of Northwestern Ontario. The storm brought strong thunder and lightning storms with damaging winds to areas close to the Manitoba border. The cause of interruption for the Major Event falls under primary cause 2 - Loss of Supply. The storm resulted in a loss of supply to 510 customers in Pikangikum in the Red Lake Region, representing about 12% of Remotes' total customer base. The major event began during the afternoon (15:00) of September 20th and power was restored to all customers at 18:30 hours on September 21st, resulting in an interruption lasting 27.5 hours, 13,974 customer hours of interruption, and 3.4 SAIDI minutes/day.

Prior to the major event, weather forecasts provided a weather warning throughout the region, however, no additional staff were scheduled in advance due to past storms often missing Remotes' communities since they are small and isolated. However, in this case the storm hit the community and the municipality of Red Lake declared a "State of Emergency" during the major event.

Most of the damage was to the Transmission and Distribution system in the Red Lake region to the south of the community, operated by HONI and Watay Power which resulted in an outage for which

Remotes had no direct control in resolving. Developing a communication and coordination plan with other parties may be an objective for Remotes in the future. Actions and timelines were provided regularly to the council as well as to those customers who contacted the Call Centre. Remotes also provided outage updates to ISC. Remotes did not use its websites or social platforms for the purpose of outage notification and information, however in the future, the issuance of press releases, press conferences, and social media notifications during these types of events will be more fully explored.

Outages Experienced by Cause Codes

The root cause of power interruptions is monitored and analyzed by Remotes. Each power outage that occurs on Remotes' distribution system is recorded and an outage cause code is assigned. The number of customer interruption hours for each cause code provides a picture of the root cause of power interruptions. There are no targets for root cause of power interruptions, but it is monitored for investment planning purposes. Remotes' reliability metric values for the historical period are shown in the tables and figures below.

Table 5.2-20 presents the number of outages broken down by cause code for the historical period. The number of outages is an indication of outage frequency and impacts customers differently based on customer class. Remotes continues to assess and execute capital and O&M projects to manage the number of outages experienced.

Table 5.2-20: Outage Numbers by Cause Codes

Cause Code	2017	2018	2019	2020	2021	Total Outages	%
0-Unknown/Other	1	0	6	1	12	20	1%
1-Scheduled Outage	44	24	48	187	92	395	29%
2-Loss of Supply	149	124	89	127	128	617	44%
3-Tree Contacts	8	5	10	13	5	41	3%
4-Lightning	7	4	2	7	5	25	2%
5-Defective Equipment	15	15	14	26	17	87	6%
6-Adverse Weather	6	4	15	14	2	41	3%
7-Adverse Environment	11	8	7	3	10	39	3%
8-Human Element	2	1	4	1	0	8	1%
9-Foreign Interference	15	15	33	22	29	114	8%
Total:	**258**	**200**	**228**	**401**	**300**	**1,387**	**100%**

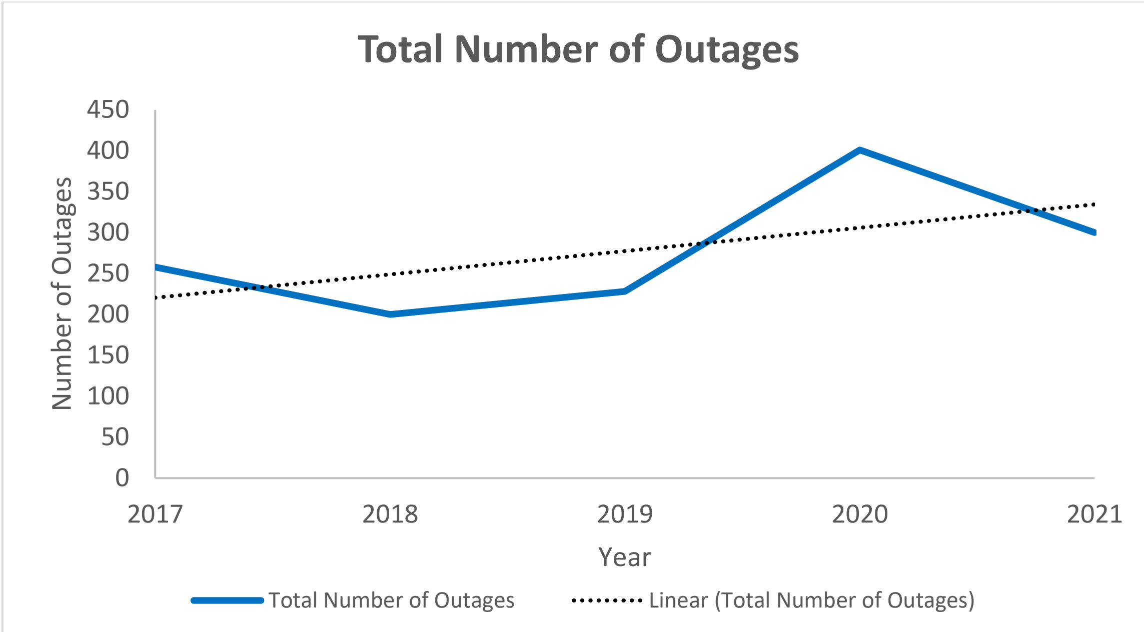


Figure 5.2-22: Total Number of Outages per Year

The total annual number of interruptions over the historical period varies from a low of 200 to a high of over 400, with the overall trend increasing in the period. This represents an average of 0.548 to 1.096 interruptions per day.

A summary of the causes of outages within Remotes' system is presented in the following graph along with the percentage of overall outage incidents attributable to each cause type.

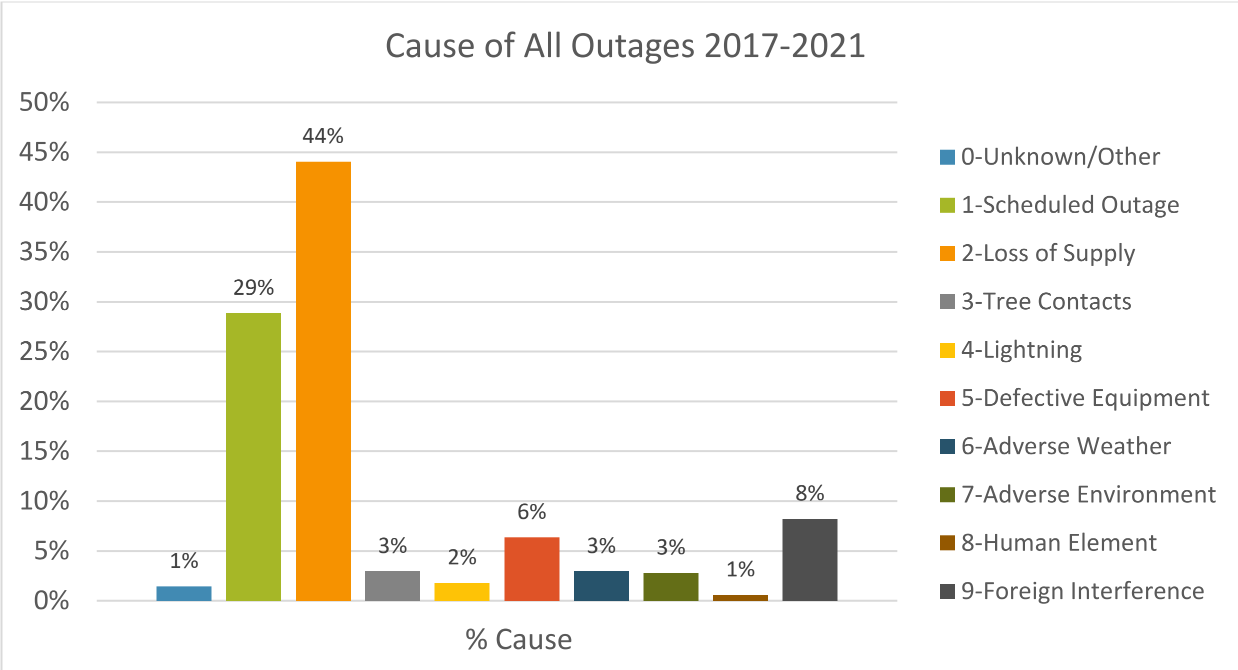


Figure 5.2-23: Causes of All Outages from 2017 - 2021

Loss of Supply and Scheduled Outages represent the two single largest causes for outages on Remotes' distribution system over the last 5 years. Together, these causes contributed to 73% of total number of outages from 2017 to 2021, excluding MEDs. Loss of Supply is the top contributing cause to the total outages experienced by Remotes.

Loss of supply outages occur due to problems at the generating station such as the generator, fuel supply system, station auxiliary systems, PLC, circuit breakers, or transformers. Remotes has planned several investments over the forecast period to address loss of supply outages. Generator overhauls are planned to refurbish the engine based on manufacturers' guidelines to maintain the reliable operation of the generator. After 2 overhauls, it is no longer economical to overhaul the generator to ensure reliability so and its replacement is planned. Remotes has planned several generator replacements over the forecast period based on the maintenance history of the unit, the number of engine-hours, and the asset condition. SCADA and PLC upgrades at Remotes' generating stations will improve outage response time by enabling remote alarm handling and troubleshooting. Non-capital investments to reduce loss of supply outages includes planned maintenance on generators as described in Section 5.3.3.

At 29%, Scheduled Outages are the second top contributing cause to the total outages experienced by Remotes. These outages are due to the disconnection of service for Remotes to complete capital investments or to perform maintenance activities on assets that require them to be disconnected for employee safety. Remotes aims to mitigate the impact of these outages through proactive planning and advanced notice with the affected communities. The planning approach of bundling of work in a community helps to reduce the number of outages and duration customers experience on an annual basis. Unlike other utilities, for Remotes we plan scheduled outages for both generation and distribution. Generation scheduled outages are often necessary to remove all sources of energy so workers can safely perform the maintenance such as main station switch gear electrical bus, main breaker repairs or work on the step-up transformers. Distribution requires scheduled outages for maintenance, complex connections as we do not have the appropriate live line equipment at remote sites due to safety certification logistics and cost.

At 8% and 6%, Foreign Interference and Defective Equipment represent the next largest causes for outages on Remotes' distribution system. The outages contributing to the Foreign Interference cause code include animal interference and/or foreign objects. Some of these contributing factors can be minimized by installing animal guards in areas observed to have a high activity of animals, for example. However, other incidents can happen at random and depending on the extent and where they happen, may result in a large impact.

Defective Equipment failures result from equipment failures due to condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. Remotes has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage. This includes replace aging and defective poles, re-string conductors, and re-align poles. Remotes utilizes asset condition data to assist in prioritizing investments in asset classes.

Customers Interrupted and Customers Hours Interrupted

The number of Customers Interrupted (CI) is a measure of the extent of outages and Customer Hours Interrupted (CHI) is a measure of outage duration and the number of customers impacted. The tables and graphs below provide the historical values and trends for both CI and CHI. The top two cause codes remain the same for the analysis of total customers interrupted and customer hours interrupted, however, when observing the customer hours interrupted, *Adverse Weather* is also a major contributor.

Table 5.2-21 Customers Interrupted Numbers by Cause Codes

Cause Code	2017	2018	2019	2020	2021	Total CI	%
0-Unknown/Other	66	0	1,005	3	1,179	2,253	1%
1-Scheduled Outage	6,751	3,278	2,216	6,547	4,205	22,997	12%
2-Loss of Supply	28,484	25,310	17,990	26,597	25,553	123,934	66%
3-Tree Contacts	1,430	69	1,405	1,225	717	4,846	3%
4-Lightning	432	412	103	890	466	2,303	1%
5-Defective Equipment	1,359	42	1,150	2,611	709	5,871	3%
6-Adverse Weather	268	234	3,760	1,522	764	6,548	3%
7-Adverse Environment	1,984	1,677	2,118	8	2,446	8,233	4%
8-Human Element	509	363	305	91	0	1,268	1%
9-Foreign Interference	1,482	1,283	2,671	1,651	2,901	9,988	5%
Total:	**42,765**	**32,668**	**32,723**	**41,145**	**38,940**	**188,241**	**100%**

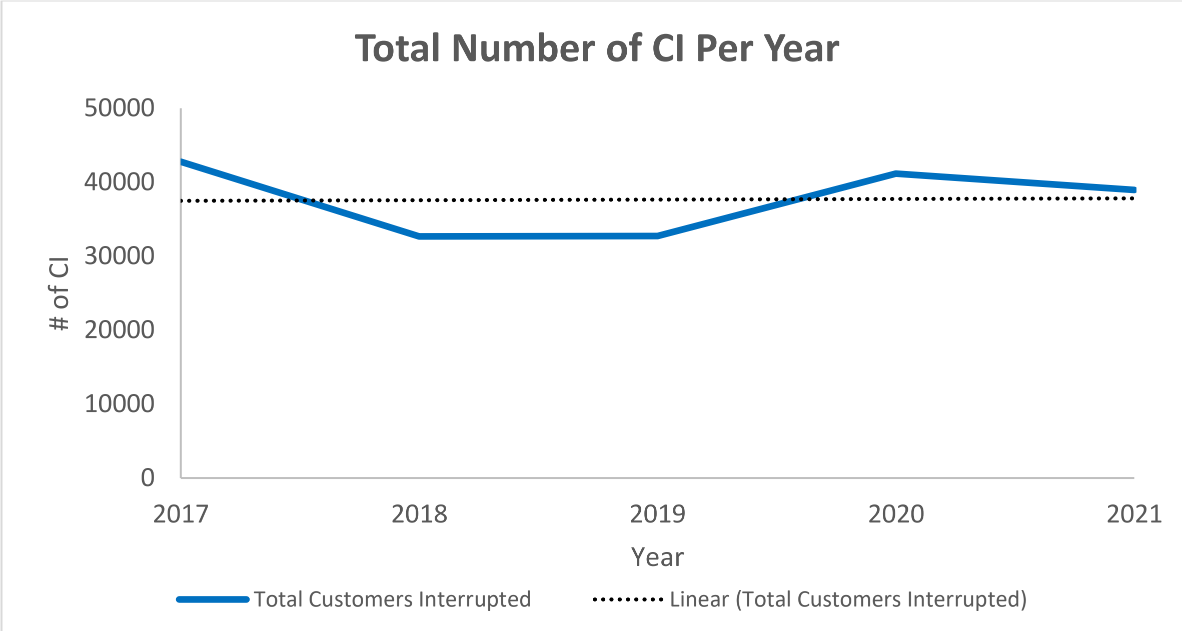


Figure 5.2-24: Total Number of CI per Year

Table 5.2-22 Customer Hours Interrupted Numbers (rounded) by Cause Codes

Cause Code	2017	2018	2019	2020	2021	Total CHI	%
0-Unknown/Other	75	0	913	4	2,222	3,214	1%
1-Scheduled Outage	11,123	3,838	5,271	11,554	9,402	41,188	17%
2-Loss of Supply	9,697	16,499	8,826	28,868	19,679	83,569	36%
3-Tree Contacts	5,124	304	2,778	4,265	6,092	18,563	8%
4-Lightning	404	5,662	66	1,571	773	8,476	4%
5-Defective Equipment	4,795	500	1,981	4,131	4,264	15,671	7%
6-Adverse Weather	2,642	2,264	22,522	8,862	274	36,564	16%
7-Adverse Environment	1,409	2,456	1,287	36	2,026	7,214	3%
8-Human Element	67	6	25	56	0	154	0%
9-Foreign Interference	1,433	2,919	4,495	4,715	3,991	17,553	8%
Total:	**36,769**	**34,448**	**48,164**	**64,062**	**48,723**	**232,166**	**100%**

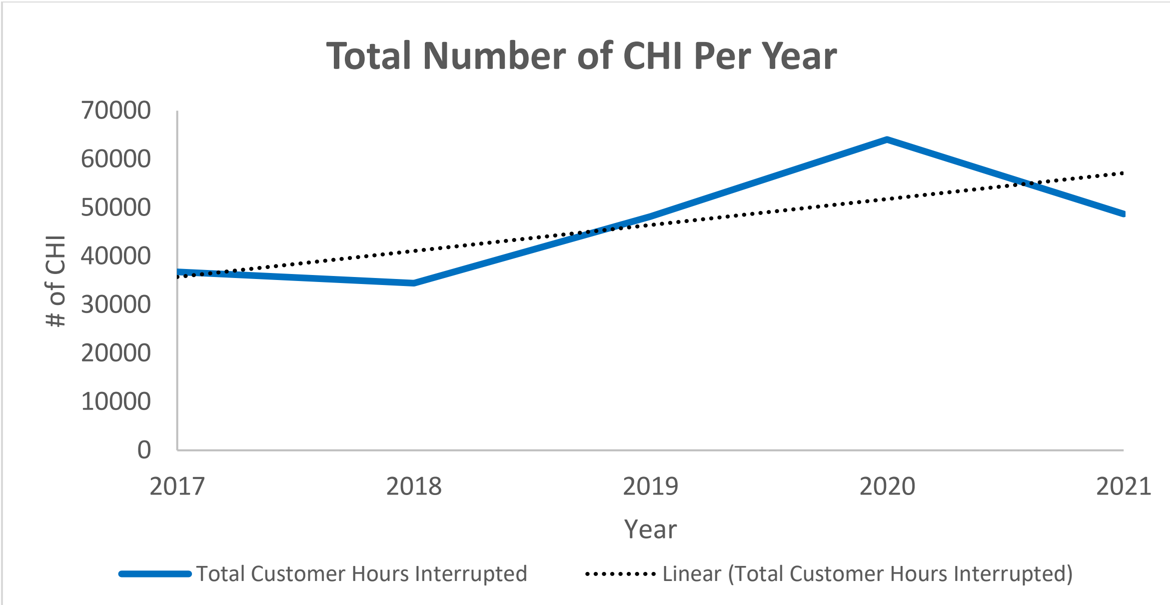


Figure 5.2-25: Total Number of CHI Per Year

The trend for total number of customers interrupted over the historical period is stable, and only minor variations are observed year over year given that reliability statistics and measures are very granular in nature for Remotes and subject to volatility. Scheduled Outages and Loss of Supply remain the top causes of total customers interrupted over the historical period.

An increasing trend is seen for the total number of customer hours interrupted over the historical period. The observed increase in 2019 can be attributed to adverse weather, and the increase in 2020 can be attributed to adverse weather and defective equipment. In both cases, scheduled outages and loss of supply are still among the top causes impacting the customer hours interrupted.

Within the DSP plan period, there are several ongoing and planned efforts to manage the number of controllable outages and continue meeting established reliability targets. These efforts include:

- Distribution system improvements, which includes replacements of aging or defective poles, conductor restringing, and pole re-alignments based on the asset condition surveys;
- Engine overhauls and planned replacements of end-of-life generators;
- Ongoing proactive vegetation management; and
- Ongoing inspection & maintenance of assets to identify and mitigate potential problems.

5.2.3.1.3.3 Distributor Specific Reliability Targets

Remotes' fixed performance baseline targets for SAIDI and SAIFI are established based on historical performance.

The updated fixed performance baseline targets for distribution SAIDI and SAIFI for the forecast period are set based on the average historical performance for years 2017-2021, excluding LOS and MED. This corresponds to an updated target of 6.81 for SAIDI, and 3.29 for SAIFI. In addition to meeting the fixed performance baseline targets, SAIDI and SAIFI trending is done by comparing the fixed performance baseline targets against the most recent five-year rolling average (i.e., average of the most recent five-year performance, updated annually). This information will be reported annually as part of the OEB Scorecards.

5.3 Asset Management (AM) Process

This section provides an overview of Remotes' asset management (AM) processes, a description of assets managed by Remotes, and a presentation of Remotes' asset lifecycle optimization policies and practices.

5.3.1 Planning Process

5.3.1.1 Overview

Remotes' uses a systematic approach to its AM process that is used to plan and optimize ongoing capital and O&M expenditures for its isolated electrical system, including both generation and distribution assets. The purpose of this section is to provide the OEB and other stakeholders with an understanding of Remotes' AM process, as well as link the process to expenditure decisions identified in the capital investment plan.

Remotes applies established AM principles when managing its assets. The management of these assets involves optimizing and sustaining the assets over their lifecycles and factors in performance, cost, and risk to ensure they are carried out in alignment with Remotes' strategic direction. Remotes' strategic AM objectives are divided into 4 categories of strategic business values: health and safety, stewardship, excellence, and innovation. The objectives are derived from Remotes' corporate mission and vision statements and are described in the following table.

Table 5.3-1: AM Objectives

Category	AM Objectives
Health and Safety	▪ Ensure public and worker health and safety. ▪ Design, select, operate and maintain assets with safety in mind.
Stewardship	▪ Align development work with government policies, priorities, and directives. ▪ Ensure safe, reliable and efficient operation of the Remotes' system. ▪ Ensure long-term sustainability of existing assets and equipment; system reliability and security; and customer satisfaction and environmental integrity. ▪ Be a committed and trusted partner in grid integration and development. ▪ Meet all applicable regulatory, legal and industry requirements. ▪ Enable and facilitate efficient connection of customers and maximize connection of renewable resources. ▪ Facilitate and enable the effective transformation and re-configuration of Remotes' system into a modern, intelligent, and customer-centric system. ▪ Ensure compliance in meeting potential new environmental air emission and noise requirements. ▪ Manage existing assets consistent with Remotes' environmental management system and with a strong focus on energy efficiency. ▪ Maximize/optimize useful asset life for overall cost-benefit by balancing competing requirements for operating performance, costs, and risks. ▪ Keep informed of innovation including smart grid advancement for appropriate application at the Remotes' distribution system. ▪ Level and prioritize sustainment work scope and volumes for greater effectiveness and flexibility within applicable resource constraints (e.g., financial, staff).

Category	AM Objectives
	▪ Develop the Remotes' system with a strong focus on energy efficiency, environmental awareness, and meeting potential new environmental air emission requirements. ▪ Maintain an appropriate balance and flexibility between sustainment and development work. ▪ Integrate new Independent Power communities and their assets into Remotes' on-going operations and AM cycles as they are connected to the grid. ▪ Discuss and collaborate with affected First Nations and Métis communities on development. ▪ Discuss and collaborate with affected public and stakeholders on related Remotes development.
Excellence	▪ Develop, retain, and have available a skilled, trained, productive, and flexible workforce for sustainment work, development work, and operating work. ▪ Focus on properly planned and preventive work which emphasizes excellence and safety in achieving results, while eliminating 'firefighting' and corrective maintenance. ▪ Ensure the effective development of modern, reliable, cost- effective, safe, efficient and flexible systems which are customer-oriented and meets customers' needs. ▪ Develop and operate the Remotes' system and manage existing assets, using quality information, including databases, information systems and processes.
Innovation	▪ Leverage innovative and practical technologies, processes and standards in the development and operation of Remotes' system, and to improve asset and system performance, operations, and maintenance. ▪ Leverage effective and innovative ways and means to meet the needs of customers, including customer choice and the enablement of value services to the customers. ▪ Demonstrate leadership in Remotes' system technology advancement. ▪ Continue to support and facilitate customer driven renewable energy projects in Remotes' service territory.

Remotes' vision is to be the leading utility and a trusted partner to remote communities in Ontario's north. Its mission is to supply safe, reliable, and affordable electricity to remote communities by focusing on continuous improvement, operational excellence, and outstanding customer service.

5.3.1.2 Important Changes to AM Process since last DSP Filing

Remotes' AM processes have not had any material changes compared to the previous DSP filings with the OEB. All reporting, processes, practices, and inputs remain largely intact and the same with only small continuous improvement and evolutionary changes occurring since the previous filing.

However, the Watay Project has introduced additional considerations as it relates to Remotes' asset decision making around the need and selection of generation assets and projects based on the remaining life and use since back-up power services are being introduced in selected communities. For example, shorter term and temporary generation solutions are now in play as well as the harvesting and extension of existing assets, which normally wouldn't have occurred under a prime power situation).The Watay Project is expected to drastically change Remotes' business and operations during the forecast period and Remotes' AM process will continue to evolve with these changes.

5.3.1.3 Process

Business planning is performed annually and focuses on the development of a six-year plan. The typical annual business planning process that supports Remotes' AM objectives consists of six stages:

1. Strategic direction and goals established;
2. Risk review and investment requirements;
3. Confirmation of strategic direction and goals with Hydro One Inc.;
4. Development of economic outlook and forecast assumptions;
5. Development of plans and work programs; and
6. Approval by Hydro One Inc. Senior Management, represented by the Chair and Board of Directors

Capital expenditures are identified based on Remotes' AM processes (described further below). Annually, required investments are determined based on asset condition, engine hours (for generation), load growth and external factors such as ISC funding and winter roads. Several projects/programs are treated as non-discretionary since they are *customer-initiated and fully recoverable*. These include:

- Generator upgrades;
- New customer connections and service upgrades;
- Fixed price layouts; and
- Service cancellations

Other discretionary investments are then ranked against seven risk categories: customer/reliability, regulatory, financial, operational efficiency, environmental, safety, and reputation. The decision to delay or defer a project is made based on risk. For example, for generation projects the risk of not proceeding will restrict community connections or negatively impact customer reliability, which is not supported by customers. For distribution projects the risk of not proceeding will negatively impact customer reliability, especially when travel and logistical costs for Remotes and response times are considered. Given additional community critical infrastructure risks and direct customer impacts, lengthy outages at not generally accepted by customers.

The outcome of this process is a list of investments that is consistent with Remotes' strategic goals and considers levels of investment and associated risk mitigation. A final business plan is then endorsed and confirmed by the Hydro One Inc. Senior Management, represented by the Chair and Board of Directors. The latest business plan which contains the detailed 2022 budget, and the 2023 to 2027 forecast can be found in Appendix J.

The Watay Project is expected to drastically change Remotes' business and operations during the forecast period and Remotes' AM process will continue to evolve with these changes.

5.3.1.3.1 AM Processes

Remotes has processes in place to support its AM practices for diesel generators, hydroelectric generators, and its distribution system. Each of these is described further in the following sub-sections.

Diesel Generators

Diesel generators are maintained as per manufacturer-published recommendations, including complete overhauls after specified hours. After two overhauls, a diesel generator is typically replaced as the lifecycle has then been extended twice, parts can become obsolete and newer models improve fuel efficiency. Some units may be identified for earlier replacement subject to specific issues discovered during its lifecycle usually related to reliability issues, damage, or wear. Replacement may be advanced or lengthened accordingly. The engine replacement program also includes work related to auxiliaries and sometimes station transformers and breakers. Auxiliary work is evaluated on a case-by-case basis given the site, the existing equipment in service and the proposed replacement. Often auxiliary work is influenced by the age of the station, its equipment, and the potential re-use of existing installations, with older auxiliary equipment generally requiring improvements when replacements are done.

Remotes manages its diesel generating stations by limiting the peak load at the station to 85% of the station's rating (known as the connection limit). This threshold allows for consumption growth as existing customers connect more devices to the grid without compromising the ability to supply power during peak load. When the peak load in the community nears the connection limit (triggered at 75% of the station rating) and additional load growth is forecast, the station upgrade planning process commences. In communities where there is no load growth (Hillsport, Oba, Sultan, and Biscotasing), the connection limit is not relevant planning criteria. These communities have a high number of seasonal customers, and the peak loads often occur on holiday weekends. In the past, strong community load growth has triggered frequent station upgrades which involve replacing diesel generators prior to them reaching their full life term. Figure 5.3-1 shows Remotes' AM process for diesel generators.

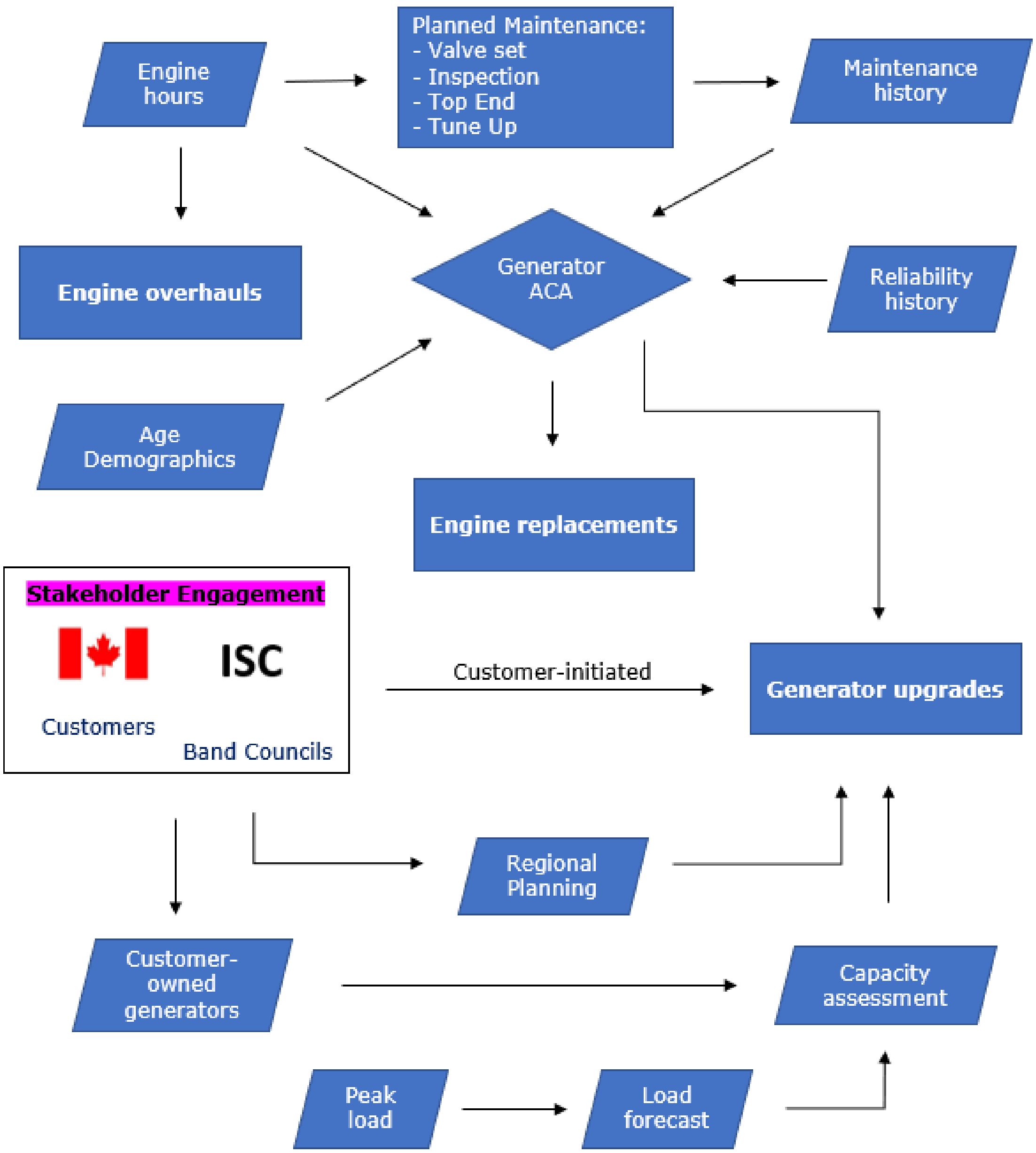


Figure 5.3-1: Remotes' AM Process for Diesel Generators

Hydroelectric Generators

Hydroelectric generators undergo on-going, routine maintenance annually or when immediate concerns are identified. Capital work for hydroelectric generators, including replacement or refurbishment, is planned based on the asset condition assessment. Figure 5.3-2 shows Remotes' AM process for hydroelectric generators.

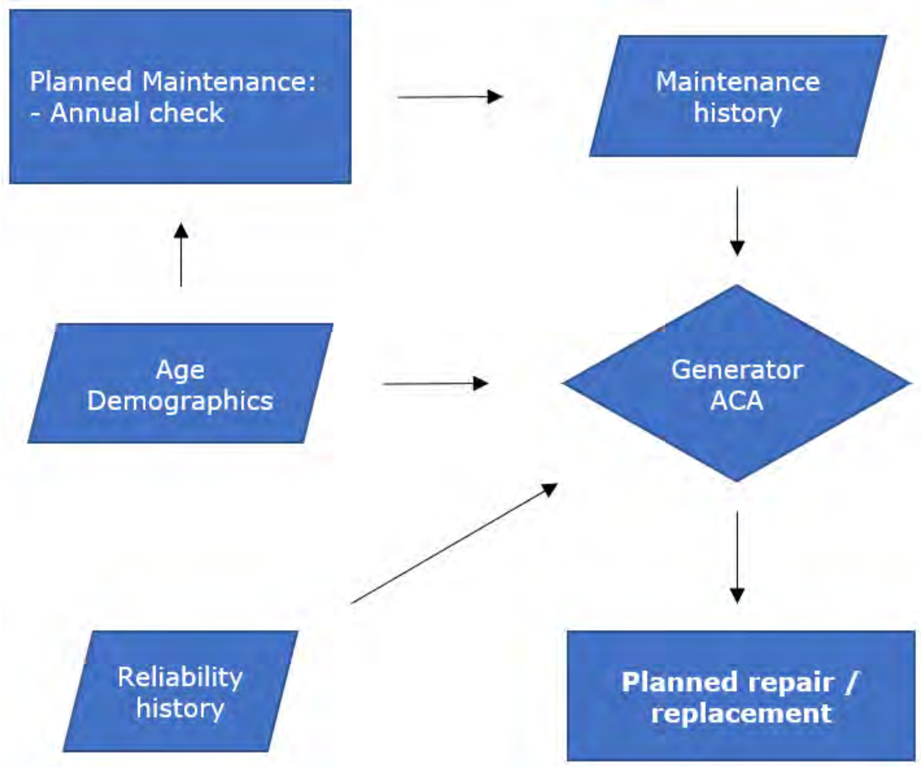


Figure 5.3-2: Remotes' AM Process for Hydroelectric Generators

Distribution System

For Remotes' distribution system, a community is selected for a betterment project each year based on asset condition, demographics, and inspection results. This includes work such as pole replacements, conductor restringing, and pole re-alignment. New customer connections, service upgrades and fixed price layouts are planned based on customer input. Figure 5.3-3 shows Remotes' distribution AM process.

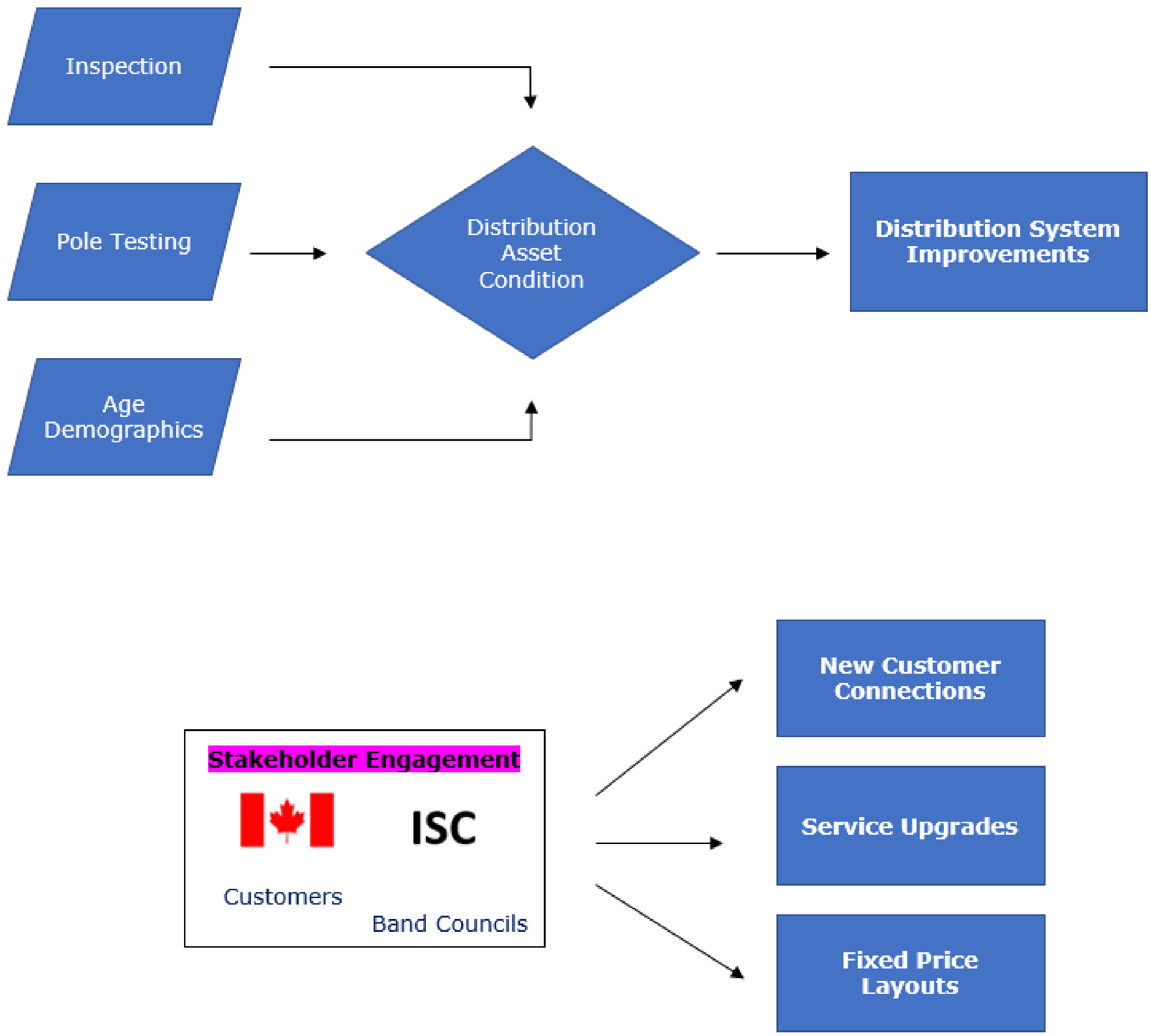


Figure 5.3-3: Remotes' Distribution AM Process

Remotes' service areas do not include large industrial customers who offer the most potential for effective demand response as other peak shaving programs. Remotes also engages in Conservation and Demand Management (CDM) activities; however, it is unlikely that CDM in its current form will provide the load capacity and specifically peak capacity relief over the longer term. Therefore, when relieving system capacity and operational constraints, Remotes considers alternatives on both the distribution and generation side, including REG investments, as well as planned transmission system connections.

5.3.1.4 Data

Remotes uses multiple datasets and inputs to assess the status of its assets and to assist in determining the capital and operational investments to be made in the system. Remotes conducts its business planning process annually to ensure that planning aligns with the strategic AM objectives of the organization and that investments are being made based on the latest information.

For diesel generators, Remotes considers engine hours, age demographics, maintenance history and reliability history information to compile the condition of its generators. In addition to condition, Remotes also gathers information on peak and forecast loads, regional planning objectives and customer growth and development projects to better understand the needs of communities. Together, this information is then used to inform what type of work is needed (if any), which can include overhauls, replacements and/or upgrades.

For hydroelectric generators, the primary input data considered includes age demographics, maintenance history and reliability history. This information is used to compile the generator condition, which then informs whether the assets require planned repair or replacement.

For its distribution system, Remotes looks at pole testing, inspection data, and age demographic information to compile the distribution asset condition. The distribution asset condition is then compared to other asset classes and distribution system improvements are identified for inclusion into the Remotes' planning processes. Distribution system access projects are primarily informed by engagements with customers, Band Councils and the ISC.

In addition to the above, Remotes' overarching planning process is also informed by its strategic AM objectives, which are derived from Remotes' corporate mission and vision statements. The needs of customers, communities, Band Councils and the OEB's performance objectives are also key inputs to Remotes' planning process. External drivers, which may be political, economic, social, technological, environmental, or regulatory/legal related, may sometimes influence Remotes' decision-making as well. One example of an external driver which will greatly impact Remotes' future decision making is the Watay Project.

5.3.2 Overview of Assets Managed

This section presents a description of Remotes' service area, a summary of the system configuration, asset condition, and Remotes' system utilization relative to planning criteria.

5.3.2.1 Description of Service Area

5.3.2.1.1 Overview of Service Area

Remotes' distribution system currently serves 21 off-grid communities and one grid connected community, each with specific needs. Nineteen of these sites have stand-alone generation systems. These communities are comparatively small, and most do not have year-round road access. As a predominantly isolated and remote distribution system, Remotes serves very few customers spread over a large area.

There are ten communities currently serviced by Remotes diesel generation that will be connected to the grid between 2022 and 2024 via the Watay Project. One of these communities, Pikangikum, is already connected, but is expected to be re-connected using a higher voltage feed in 2022. In the same timeframe, Remotes will also take on six additional grid-connected IPA communities, and Cat Lake. The specific energization timing and community breakdown, which is based on an excerpt from the Watay Project schedule as of October 2021, is shown in Figure 5.3-4. It is likely that the presented Watay Project connection dates will generally slip over time given construction delays and earlier COVID-related delays during the start-up phase. Remotes will continue to work with Watay and its partners to ensure timely connection.

Energization Dates by Community		
Date		**Community**
Connected		Pikangikum
Jun-22		North Caribou Lake
Jun-22		Kingfisher Lake
May-23	IPA	Muskrat Dam
May-23		Bearskin Lake
May-23	IPA	Wunnumin Lake
May-23	IPA	Wawakapewin
Jun-23		Kasabonika Lake
Jun-23		KI + Wapekeka
Jun-23		Sachigo Lake
Apr-24	IPA	Poplar Hill
Apr-24		Deer Lake
May-24	IPA	North Spirit Lake
May-24		Sandy Lake
May-24	IPA	Keewaywin

Figure 5.3-4: Wataay Project - Energization Dates by Community

5.3.2.1.2 Climate

Remotes' service territory is vulnerable to weather extremes owing to its geographical location in northern Ontario. Conditions in most communities are best described as cold winters with relatively short summers with temperature variations best described as being extreme. In general, consumers in Northern Ontario require more electricity for heating related purposes rather than for cooling related purposes. The ability of staff to respond to and repair facilities can be hampered by severe weather, especially with respect to cancelled or delayed flights or a plane's inability to land. Weather conditions can also have an adverse effect on capital and maintenance plans when experiencing extreme cold or heavy snowfalls. As well, the shortened construction season also requires strong project readiness and execution. The availability of winter roads can also impact the transportation of equipment to site.

5.3.2.1.3 Economic Growth

Economic growth in the communities served by Remotes has been and is expected to continue to be low to moderate. As shown previously in Table 5.2-2, a slight growth in the numbers of customers has been forecast in most communities. As customers plug in more devices, electricity usage is becoming more intensive, but electric heat has been the largest driver of electricity usage in recent years. Federal and indigenous initiatives will also impact economic growth. Table 5.3-5 below presents the resultant peak load forecast for each community based on these factors.

With the addition of seven new communities to Remotes' customer base over the forecast period, Remotes is also expecting to see growth in both its customer count and amount of energy delivered over the forecast period.

5.3.2.1.4 Summary of System Configuration

5.3.2.1.4.1 Distribution

Since the communities serviced by Remotes are far apart and isolated, the distribution systems are separate and independent. The distribution voltage for these distribution systems ranges from 4.16 kV to 25 kV. There are approximately 272 km of distribution lines which deliver the electricity to the 22 communities through 20 isolated distribution systems. Each distribution system consists of a single feeder. Table 5.3-2 summarizes the distribution system configuration.

Table 5.3-2: Summary of Remotes' Distribution System Configurations

Distribution System Configuration	Asset Counts
Number of 25 kV systems	16
Number of 4.16 kV systems	4
Total number of distribution systems	20
Circuit km – 25 kV	250
Circuit km – 4.16 kV	22
Total km of distribution lines	272

The increase in number of circuit kilometres over the plan period is expected to be relatively minor (i.e., less than 5% total) for communities presently served by Remotes. The communities being added to Remotes' service area over the plan period are expected to add approximately 40 circuit kilometres.

5.3.2.1.4.2 Generation

Remotes owns 60 generators, of which 57 run on diesel fuel. They are rated between 60 kW to 1,500 kW. Each diesel generation station (DGS) houses between 2-4 diesel generators. Most of the DGS have 3 generators, sized to meet the loads at different times of the day. The generators are automated to run to maximize fuel efficiency by matching generator size to the electricity load of the community. Remotes handles over 120 million litres of diesel fuel each year, depending on the electrical demand of the communities.

The remaining generation is comprised of 3 hydroelectric generators with capacities ranging from 150 to 225 kW. Table 5.3-3 shows a complete list of Remotes' generators and Generator Step-up Transformers (GSUs) by community.

Table 5.3-3: Generator and GSU Capacity

Community	Generation Unit	Generator Capacity (kW)	Engine Speed (rpm)	GSU Size (kVA)
Armstrong	A	725	1,800	3 x 333
	B	725	1,800	
	C	1,100	1,800	
Bearskin Lake	A	600	1,800	3 x 500
	B	410	1,800	
	C	1,000	1,200	
	A	600	1,800	3 x 750

Community	Generation Unit	Generator Capacity (kW)	Engine Speed (rpm)	GSU Size (kVA)
Big Trout Lake	B	1,000	1,800	
	C	1,000	1,200	
	T1[1]	400	1,800	
Biscotasing	A	60	1,800	3 x 250
	B	96	1,800	
	C	143	1,800	
Deer Lake	A	1,500	1,200	1,500
	B	635	1,800	
	C	1,050	1,800	
	Hydel #1	225	-	3 x 167
	Hydel #2	225	-	
Fort Severn	A	600	1,200	3 x 333
	B	455	1,800	
	C	1,000	1,200	
Gull Bay	A	450	1,800	500
	B	180	1,800	
	C	250	1,800	
Hillsport	A	140	1,800	3 x 50
	B	140	1,800	
Kasabonika Lake	A	1,000	1,200	3 x 500
	B	1,450	1,200	
	C	600	1,800	
Kingfisher Lake	A	455	1,800	1,500
	B	1,045	1,200	
	C	725	1,800	
Lansdowne House	A	275	1,800	3 x 333
	C	600	1,800	
	D	600	1,200	
Marten Falls	A	650	1,200	1,500
	B	400	1,800	
	C	1,045	1,800	
Oba	A	65	1,800	3 x 250
	B	65	1,800	
	C	96	1,800	
Sachigo Lake	A	635	1,800	1,250
	B[2]	455	1,800	
	C	1,050	1,200	
Sandy Lake	G1	1,250	1,200	4,000
	G2	1,250	1,200	
	G3	1,500	1,200	
	G4	1,500	1,200	
Sultan	A	230	1,800	3 x 200
	B	230	1,800	

Community	Generation Unit	Generator Capacity (kW)	Engine Speed (rpm)	GSU Size (kVA)
	Hydel #1	150	-	
Wapekeka	A	820	1,200	2,500
	B	1,045	1,800	
	C	410	1,800	
Weagamow	A	600	1,800	3 x 500
	B	725	1,800	
	C	400	1,800	
Webequie	G1	400	1,800	1,000
	G2	600	1,200	
	G3	1,000	1,200	
Total Diesel Generation Capacity		37,430		
Total Hydroelectric Generation Capacity		600		
Total Capacity		**38,030**		

[1] T1 is a temporary unit
[2] The Sachigo B unit is currently removed from service and replaced by a temporary 1MW generator. Once grid connected, the temporary unit will be removed from service and the existing "B" unit will be placed back into service.

In addition, there are approximately 15 existing generators within the IPA communities, which Remotes is anticipating it will manage once these communities are added to its service area.

5.3.2.2 Asset Information

5.3.2.2.1 Capacity & Utilization

As specific communities expand, Remotes' equipment is electrically loaded and stressed to higher levels. When loading and stresses exceed the equipment design capability and nameplate ratings, the equipment must be replaced with higher capacity equipment to ensure safety and reliability of supply. Table 5.3-4 illustrates the peak load in each community over the past five years, along with the community's station capacity and the connection limit (85% of the station capacity). Table 5.3-5 shows the forecast peak loads by community over the forecast period.

Table 5.3-4: Station Rating, Connection Limit & Actual Peak Load by Community

Community	Station Rating (kW)	Connection Limit (kW)	Actual Peak Loads (kW)				
			2017	2018	2019	2020	2021
Armstrong	1,450	1,233	980	1,042	1,093	953	1,024
Bearskin	1,000	850	640	695	708	784	750
Big Trout	1,600	1,360	1,277	1,404	1,391	1,757	1,538
Biscotasing	156	133	146	161	142	188	177
Deer Lake	1,795	1,526	1,230	1,319	1,328	1,324	1,368
Fort Severn	1,000	850	589	634	615	633	617
Gull Bay	430	366	325	337	343	288	340
Hillsport	125	106	94	83	83	86	98
Kasabonika	1,600	1,360	1,018	1,086	1,147	1,141	1,169

Community	Station Rating (kW)	Connection Limit (kW)	Actual Peak Loads (kW)				
			2017	2018	2019	2020	2021
Kingfisher	1,055	897	614	650	660	630	743
Lansdowne	875	744	451	605	626	703	691
Marten Falls	650	553	475	457	565	605	582
Oba	120	102	64	68	57	80	86
Sachigo	1,000	850	677	752	750	976	947
Sandy Lake	3,750	3,188	2,528	2,655	2,860	2,889	2,975
Sultan	150	128	120	161	149	129	152
Wapekeka	1,230	1,046	595	628	702	713	892
Weagamow	1,300	1,105	979	1,035	1,064	1,083	1,175
Webequie	1,000	850	633	707	813	821	872

Table 5.3-5: Forecasted Peak Loads by Community

Community	Forecast Peak Load (kW)					
	2022	2023	2024	2025	2026	2027
Armstrong	1,074	1,090	1,107	1,123	1,140	1,157
Bearskin	790	814	838	863	889	916
Big Trout	1,680	1,714	1,748	1,783	1,819	1,855
Biscotasing	184	186	188	190	192	194
Deer Lake	1,389	1,409	1,430	1,452	1,474	1,496
Fort Severn	643	653	662	672	682	693
Gull Bay	348	355	362	370	377	385
Hillsport	99	100	101	102	103	104
Kasabonika	1,198	1,228	1,259	1,290	1,323	1,356
Kingfisher	765	788	812	836	861	887
Lansdowne	652	763	775	786	798	810
Marten Falls	608	624	639	655	671	688
Oba	87	88	89	89	90	91
Sachigo	981	1,000	1,020	1,041	1,062	1,083
Sandy Lake	3,079	3,187	3,298	3,414	3,533	3,657
Sultan	171	172	174	176	178	179
Wapekeka	910	928	947	966	985	1,005
Weagamow	1,216	1,259	1,303	1,348	1,396	1,444
Webequie	907	943	981	1,020	1,061	1,103

Unlike other utilities, and in most communities, Remotes experiences peak load and usage during the cold, dark winter months, generally in late January, early February.

In the four road-rail communities where there is no load growth (Hillsport, Oba, Sultan and Biscotasing), the connection limit is not relevant planning criteria. These communities have a high number of seasonal customers, and the peak loads often occur on holiday weekends.

Remotes existing feeder conductors have ample capacity for the loads in the communities. Most communities are served by 25 kV feeders with the remainder of smaller communities served by 4.16 kV systems. Given the small load sizes (below 3 MW), the feeder conductors can carry loads several times larger than the current community peak load.

The generation station transformers are sized appropriately for the diesel generation station maximum load. Accordingly, the transformers are changed as part of the generation station upgrade process when required. The funding for the First Nation communities' generation station upgrades, which includes the replacement of the station transformers, is provided by the Federal government.

5.3.2.2.2 Asset Demographics and Condition Information

The major categories of assets managed by Remotes are:

- Generators (diesel and hydroelectric)
- Generator Step-up Transformers (GSUs)
- Poles
- Distribution Transformers

Table 5.3-6 shows Remotes' current asset count.

Table 5.3-6: Asset Counts for Major In-service Generation and Distribution Assets

Generators	GSUs	Poles	Distribution Transformers
60	44	5,496	1,174

Asset Condition Assessment (ACA) results are based on a consistent approach with the objective of applying a clear and unambiguous interpretation across asset classes. Condition categories for diesel and hydroelectric generators are divided into 5 categories ranging from Very Good to Very Poor based on the definitions in Table 5.3-7. Poles only have 3 condition categories which include R0, R2 and R1, which translate to Good, Poor and Very Poor, based on definitions in Table 5.3-8. GSUs and distribution transformers are not assigned a specific condition category as only age data is available for these assets, however Remotes regularly inspects these assets for signs of damaged or leaking equipment requiring replacement.

Table 5.3-7: Definition of Asset Conditions for Generators, GSUs & Distribution Transformers

Condition	Description	Requirements
Very Good (VG)	Some aging or minor deterioration of a limited number of components	Normal maintenance
Good (G)	Significant deterioration of some components	Normal maintenance
Fair (F)	Widespread significant deterioration or serious deterioration of specific components	Perform risk assessment; manage risk; consider replacement or refurbishment in 5 - 10 years
Poor (P)	Widespread serious deterioration	Plan for replacement or refurbishment within the next 5 years
Very Poor (VP)	Extensive serious deterioration	Plan for immediate replacement or refurbishment

Table 5.3-8: Definition of Asset Conditions for Wood Poles

Condition	Description	Requirements
R0 (G)	No action required within 5 year period	No action required (within 5 year period)
R2 (P)	Requires Replacement	Requires Replacement (1 – 5 years)
R1 (VP)	Requires urgent replacement	Requires urgent replacement (<1 year)

Figure 5.3-5 summarizes the condition of Remotes' generators and poles, as compiled in July 2022.

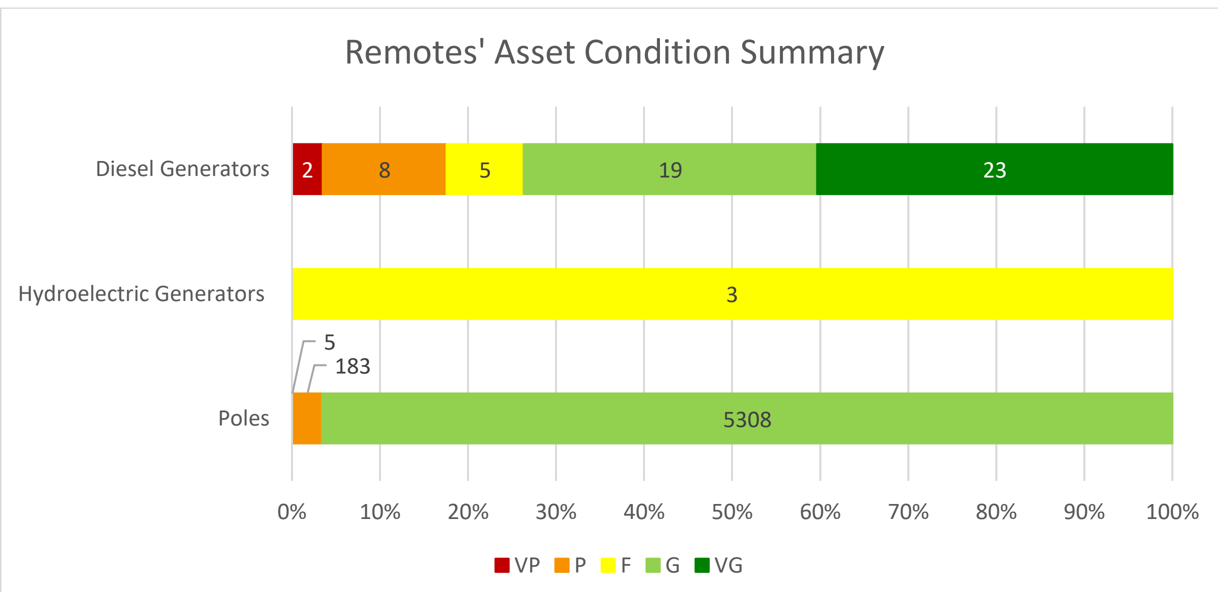


Figure 5.3-5: Summary of Remotes' Asset Condition Assessment

5.3.2.2.2.1 Generators

Remotes owns 60 generators, of which 57 run on diesel fuel. The remainder are 3 hydroelectric generators which have a longer expected lifespan. The age demographics for these generators are shown in Figure 5.3-6.

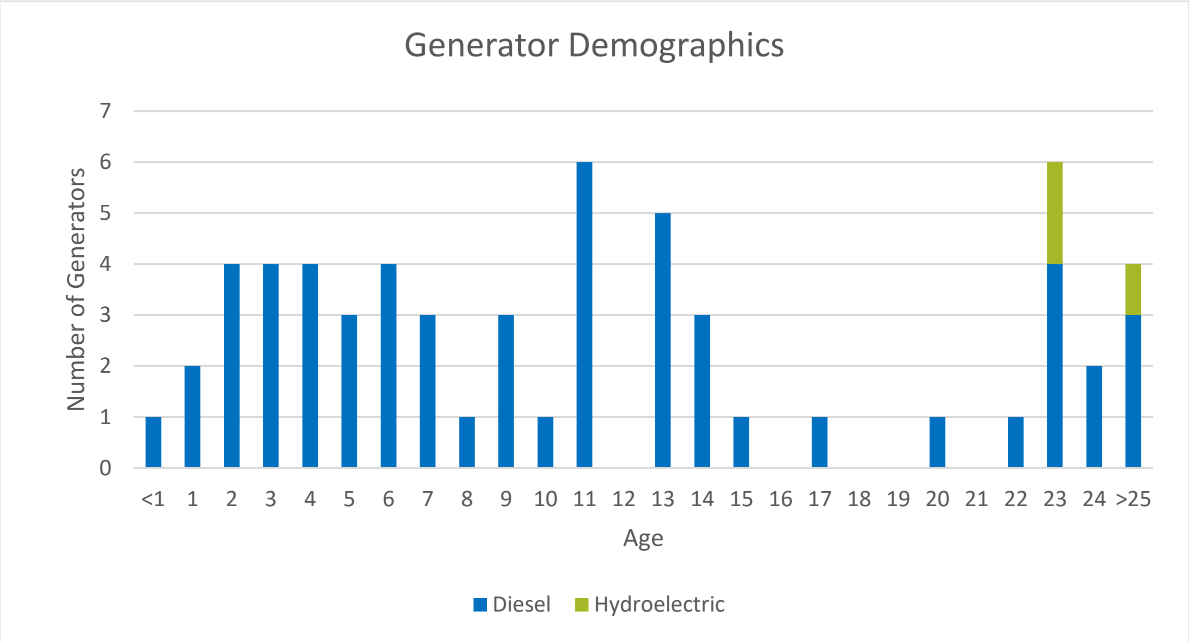


Figure 5.3-6: Age Demographics for Generators

The results of the ACA on Remotes' generators – based on engine-hours and operating experience – are summarized in Table 5.3-9. Table 5.3-10 presents the detailed in-service year, engine-hours, and condition of each unit. The condition of the hydroelectric generators is based on inspections.

Table 5.3-9: Summary of the ACA for Generators

	VP	P	F	G	VG
Diesel Generators	2	8	5	19	23
Hydroelectric Generators	0	0	3	0	0

Table 5.3-10: Generator In-service Year, Engine-hours, and Condition

Community	Generation Unit	In-service Year	Engine-hours [as of Feb 8, 2022]	Condition	Planned Status Changes over the Forecast Period[5]
Armstrong	A	2018	77,766	P	2024 Replacement
	B	2011	62,262	P	2024 Replacement
	C	1999	51,436	P	
Bearskin Lake	A	2009	61,506	P	2023 Backup
	B	2016	18,136	VG	2023 Backup
	C	2000	22,525	VG	2023 Backup

Community	Generation Unit	In-service Year	Engine-hours [as of Feb 8, 2022]	Condition	Planned Status Changes over the Forecast Period[5]
Big Trout Lake	A	1996	62,364	P	2023 Backup
	B	2019	17,178	VG	2023 Backup
	C	2005	61,510	G	2023 Backup
	T1[1]	1999	6,638	P	2023 Decommissioning
Biscotasing	A	2012	11,635	G	
	B	2020	5,133	VG	
	C	2019	13,460	G	
Deer Lake	A	2016	6,963	VG	2024 Backup
	B	2016	24,206	G	2024 Backup
	C[3]	2022	0	VG	2024 Backup
	Hydel #1	1999	-	F	
	Hydel #2	1999	-	F	
Fort Severn	A	1998	92,202	F	
	B	2013	37,552	G	
	C	2015	3,638	VG	
Gull Bay	A	2009	22,071	G	
	B	2020	4,824	VG	2023 Upgrade
	C	2011	20,146	G	
Hillsport	A	2007	66,704	P	
	B	2021	1,160	VG	
Kasabonika Lake	A	1998	102,914	P	2023 Backup
	B	2015	9,776	VG	2023 Backup
	C	2009	26,001	G	2023 Backup
Kingfisher Lake	A	2009	49,703	F	2022 Backup
	B	2017	6,036	VG	2022 Backup
	C	2017	20,009	VG	2022 Backup
Lansdowne House	A	2019	2,813	VG	2024 Upgrade
	C	2014	49,104	F	2024 Replacement
	D	1999	19,518	VG	
Marten Falls	A[4]	1982	95,946	VP	2022 Replacement
	B	2018	10,856	VG	
	C	2021	1,528	VG	
Oba	A	2018	11,952	VG	
	B	2019	11,261	VG	
	C	2011	12,049	G	
Sachigo Lake	A	2013	27,800	G	2023 Backup
	B[2]	2009	27,800	G	2023 Backup
	C	2002	43,994	G	2023 Backup
Sandy Lake	G1	2008	69,688	F	2024 Backup
	G2	2008	43,832	G	2024 Backup
	G3	2013	18,555	VG	2024 Backup

Community	Generation Unit	In-service Year	Engine-hours [as of Feb 8, 2022]	Condition	Planned Status Changes over the Forecast Period[5]
	G4	2020	3,567	VG	2024 Backup
Sultan	A	2017	18,607	G	
	B	2018	16,910	G	
	Hydel #1	1982	-	F	
Wapekeka	A	1999	66,260	F	2023 Backup
	B	2020	5,378	VG	2023 Backup
	C	2015	25,418	G	2023 Backup
Weagamow	A	1996	93,728	VP	2022 Decommissioning
	B	2016	18,184	VG	2022 Decommissioning
	C	2008	28,889	G	2022 Decommissioning
Webequie	G1	2011	22,531	G	2023 Upgrade
	G2	2011	51,291	G	
	G3	2011	22,590	VG	

[1] T1 is a temporary unit

[2] The Sachigo B unit is currently removed from service and replaced by a temporary 1MW generator. Once grid connected, the temporary unit will be removed from service and the existing B unit will be placed back into service.

[3] Deer Lake C unit was replaced in Spring 2022.

[4] Marten Falls A unit to be replaced in summer 2022 with a similar used unit with reduced running hours.

[5] The anticipated Backup dates are in accordance with the October 2021 Watay Project schedule.

Two of the diesel generators are in Very Poor condition: Marten Falls A and Weagamow A. Remotes is replacing the Marten Falls A in summer 2022 and decommissioning the Weagamow engines in 2022 once the community is connected to the grid.

The following diesel generators are in Poor condition: Armstrong A, Armstrong B, Armstrong C, Bearskin Lake A, Big Trout Lake A, Big Trout Lake Temp, Hillsport A and Kasabonika A. Bearskin Lake A was last overhauled in 2021 and Bearskin will be connected to the grid in 2023 in accordance with the October 2021 Watay Project schedule. Remotes is planning to replace Big Trout Lake A in 2023, and Armstrong A and B units in 2024. The Big Trout Lake Temp unit will also be decommissioned in 2023. Although the Armstrong C unit is approaching end of life, Remotes is considering running the unit beyond the normal replacement timelines knowing that the other two newer units will operate the majority of hours and provide an added level of reliability. Hillsport is a small community that has a temporary unit that can be utilized to manage the impact of an unplanned failure. Kasabonika A Unit was last overhauled in 2020 and Kasabonika will be connected to the grid in 2023 per the October 2021 Watay Project schedule.

As part of its planning and AM process, Remotes also projects the number of engine-hours for each of its diesel generators for each year of the forecast period. Table 5.3-11 presents the year-end forecast for the years 2023 to 2027.

Table 5.3-11: Forecast Engine-Hours for Diesel Generators

Community	Generation Unit	Forecast Engine-Hours (1st of the year)					Anticipated Grid Connection[1]
		2023	2024	2025	2026	2027	
Armstrong	A	80,904	84,045	87,185	90,325	93,466	Not applicable
	B	65,609	68,957	72,302	75,561	78,998	
	C	53,486	56,035	58,583	61,131	63,679	
Bearskin Lake	A	63,551	64,751	64,851	64,951	65,051	May 2023
	B	22,905	25,505	25,605	25,705	25,805	
	C	24,167	25,267	25,367	25,467	25,567	
Big Trout Lake	A	63,857	100	200	300	400	June 2023
	B	23,562	100	200	300	400	
	C	62,961	100	200	300	400	
Biscotasing	A	12,001	12,704	13,407	14,110	14,813	Not applicable
	B	7,157	9,537	11,917	14,297	16,677	
	C	18,566	23,760	28,954	34,148	39,343	
Deer Lake	A	10,215	13,707	15,607	15,707	15,807	April 2024
	B	26,887	29,568	30,968	31,068	31,168	
	C	2,000	4,693	6,093	6,193	6,293	
Fort Severn	A	96,560	101,167	105,774	110,381	114,988	Not applicable
	B	41,255	44,973	48,690	52,407	56,124	
	C	3,794	4,211	4,628	5,046	5,463	
Gull Bay	A	24,804	27,945	31,945	35,945	39,945	Not applicable
	B	8,766	1,500	4,500	7,500	10,500	
	C	21,072	22,102	23,131	24,161	25,190	
Hillsport	A	71,736	77,021	82,306	87,591	92,876	Not applicable
	B	2,438	3,967	5,496	7,025	8,554	
Kasabonika Lake	A	107,961	110,661	110,761	110,861	110,961	June 2023
	B	11,303	12,353	12,453	12,553	12,653	
	C	27,924	28,974	29,074	29,174	29,274	
Kingfisher Lake	A	52,453	52,553	52,653	52,753	52,853	June 2022
	B	7,397	7,497	7,597	7,697	7,797	
	C	24,196	24,296	24,396	24,496	24,596	
Lansdowne House	A	5,077	7,341	9,605	11,869	14,133	Not applicable
	C	54,945	60,826	66,706	72,586	78,467	
	D	20,687	22,322	23,957	25,592	27,227	
Marten Falls	A	43,000	44,440	45,879	47,319	48,758	Not applicable
	B	14,270	17,686	21,103	24,519	27,935	
	C	2,830	4,604	6,379	8,153	9,928	
Oba	A	14,755	17,578	20,400	23,223	26,045	Not applicable
	B	16,208	21,446	26,684	31,921	37,159	
	C	14,053	16,271	18,490	20,708	22,927	
Sachigo Lake	A	30,912	32,612	32,712	32,812	32,912	June 2023
	B	35,695	36,995	37,095	37,195	37,295	
	C	46,620	48,270	48,370	48,470	48,570	

Community	Generation Unit	Forecast Engine-Hours (1st of the year)					Anticipated Grid Connection[1]
		2023	2024	2025	2026	2027	
Sandy Lake	G1	74,701	80,122	82,922	83,022	83,122	May 2024
	G2	49,615	55,417	58,417	58,517	58,617	
	G3	21,238	24,416	26,116	26,216	26,316	
	G4	5,474	7,848	9,148	9,248	9,348	
Sultan	A	21,946	25,357	28,768	32,180	35,591	Not applicable
	B	21,480	26,483	31,485	36,487	41,490	
Wapekeka	A	69,287	71,087	71,187	71,287	71,387	June 2023
	B	8,113	9,613	9,713	9,813	9,913	
	C	28,550	30,400	30,500	30,600	30,700	
Weagamow	A	Grid Connected with no Backup Power					June 2022
	B						
	C						
Webequie	G1	24,788	27,120	29,451	31,782	34,113	Not applicable
	G2	55,935	60,601	65,267	69,933	74,599	
	G3	25,347	28,605	31,863	35,121	38,379	

[1] The anticipated grid connection dates are in accordance with the October 2021 Watay Project schedule.

5.3.2.2.2.2 Generator Step-up Transformers

The age demographics for the in-service GSUs owned by Remotes are shown in Figure 5.3-7.

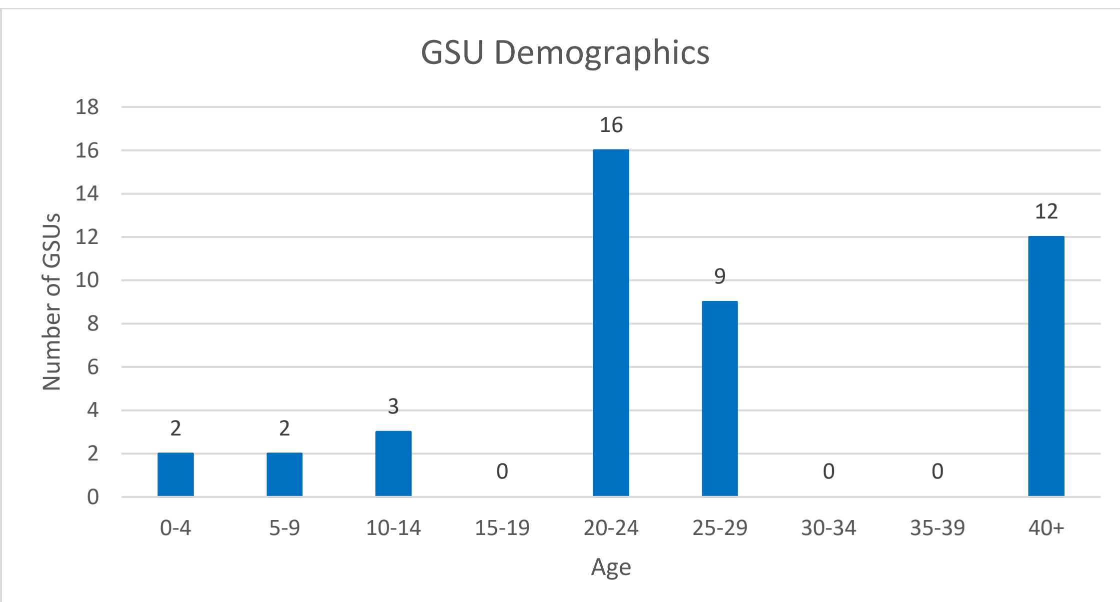


Figure 5.3-7: Age Demographics for GSUs

Remotes has not had a failure on any of its GSUs to date. For this reason, and because Remotes keeps a spare GSU at each location, Remotes employs a run to failure strategy for its GSUs. GSUs are also visually inspected annually for any signs of damage or leakage, so if any damaged or leaking GSUs are identified, they will be replaced as needed. The only time GSUs are proactively replaced is when replacement is triggered as part of a capacity upgrade. Other than the GSU replacements planned as part of the two capacity upgrade projects (i.e., the Gull Bay (KZA) DGS Upgrade and the Lansdowne House (Neskantaga) DGS Upgrade), there are no other GSU's replacements currently planned during the DSP plan period as existing assets in service are expected to provide continued value.

5.3.2.2.2.3 Poles

Remotes owns 5,496 poles, a large portion of which are between 30 and 40 years old. The average pole age on the system is 29 years. Figure 5.3-8 presents the pole age demographics.

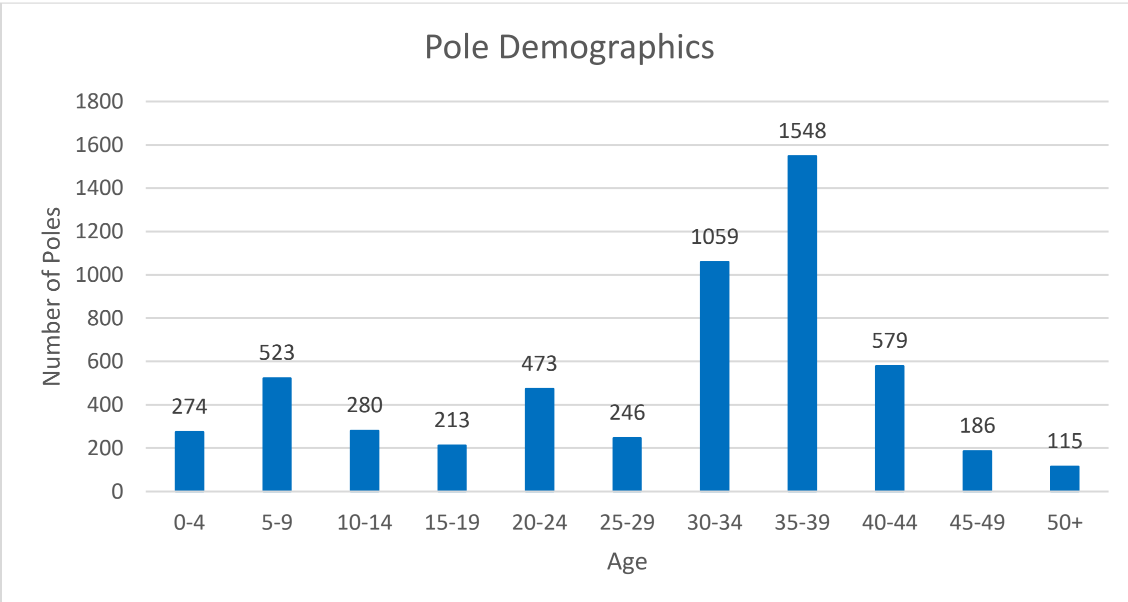


Figure 5.3-8: Age Demographics for Poles

Remotes' ACA for poles considers 3 categories:

Very Poor (R1) – emergency replacement
Poor (R2) – replace within five years
Good (R0) – no replacement over next five years

An inspection was done on Remotes' wood poles in 2021 in every community. The inspections included a helicopter patrol of the line from Armstrong to Collins, which is too labour intensive to patrol on foot. The community of Collins does not have road or plane access and must be reached by train or helicopter. The poles on this line are, therefore, replaced only on emergency response. The inspection included the following:

1. A hammer test is performed on each pole
2. A prodding test for surface rot or deterioration is performed on each pole
3. A visual (condition) test is performed on each pole
4. Rating values recorded as follows:
    - R0
    - R1
    - R2

Other visual defects, for example woodpecker damage, are assessed as part of the inspection.

Table 5.3-12 summarizes the results of the ACA for poles. All R1 poles have either been replaced immediately after identification or have been made safe for completion by the fall of 2022. Over the next five years, Remotes is planning to replace 183 poles identified to be in poor (R2) condition and any remaining emergency (R1) poles that have not already been replaced, for a total of 188 pole replacements. Additional pole replacements may be required to maintain clearances or as trouble or damage dictates.

Table 5.3-12: Summary of the ACA for Poles

Emergency (R1)	Replace Within 5 Years (R2)	No Replacement Within 5 Years (R0)
5	183	5,308

Based on the age demographics, a significant number of poles will be approaching end-of-life around the year 2040. Actual end-of-life assessment will be made based on condition. It is noteworthy that poles in colder climates tend to see less deterioration and insect damage and it may provide a lengthening effect on the end-of-life expectancy.

5.3.2.2.2.4 Distribution Transformers

Remotes currently owns 1,174 distribution transformers. Figure 5.3-9 shows the age demographics for Remotes' distribution transformers.

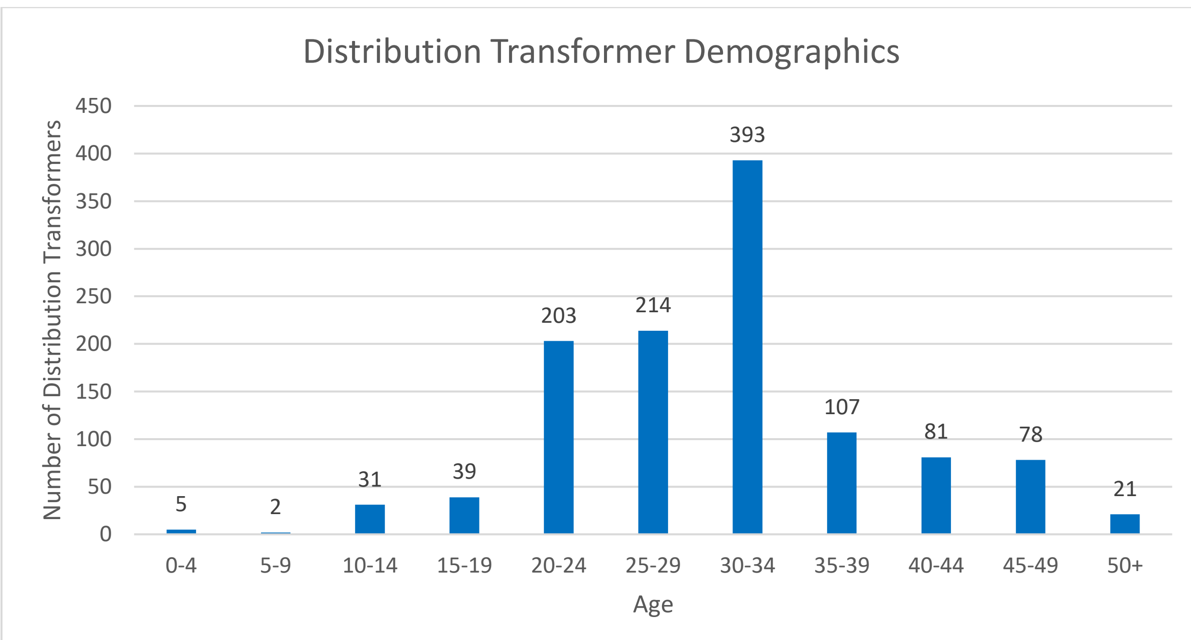


Figure 5.3-9: Age Demographics for Distribution Transformers

Remotes has experienced a relatively minor number of distribution transformer failures historically (an average of 5-8 failures per year), and distribution transformers are generally lightly loaded which helps to extend the service life of the assets. Remotes expects a similar average failure rate over the DSP plan period and will continue to replace failed transformers on a reactive basis as required. In addition, transformers older than 1985 are generally replaced during other concurrent maintenance or upgrade activities such as pole replacement or relocates. Remotes also regularly patrols their distribution lines to identify any structural problems or damaged equipment, so if any damaged or leaking distribution transformers are identified, they will be replaced as needed.

5.3.2.2.3 Asset Risks

As previously noted in Section 5.3.1.3, discretionary asset investments are ranked against seven risk categories: customer/reliability, regulatory, financial, operational efficiency, environmental, safety, and reputation. The decision to delay or defer a project is made based on risk. The outcome of this process is a list of investments that is consistent with Remotes' strategic goals and considers levels of investment and associated risk mitigation.

5.3.2.3 Transmission or High Voltage Assets

Remotes does not have any transmission or high voltage assets deemed previously, or requesting to be deemed, by the OEB as distribution assets.

5.3.2.4 Host & Embedded Distributors

Remotes is not a host distributor.

Remotes' distribution plant is predominantly fed from generation that is owned and operated by Remotes. One exception to this is Pikangikum, which is currently fed from Watay Power, who is currently a Distributor/Transmitter under a modified framework.

In the current DSP timeframe, 16 communities (including Pikangikum) will be connected at distribution voltages from Watay Power, who will become a transmitter. Demarcation will be at the distribution assets near point of connection in each community.

5.3.3 Asset Lifecycle Optimization Policies and Practices

Remotes' assets are managed based on a lifecycle management approach, which considers and balances asset performance, costs, and associated risks during the asset service life to achieve asset optimization. Remotes investigated the relationship between capital spending and system O&M costs. Regardless of the capital spending, generator maintenance is required every 2,500 engine-hours. Due to the associated flight and fuel costs of this maintenance, there is no reduction to planned system O&M costs from capital investment.

5.3.3.1 Asset Replacement and Refurbishment Policy

Replacements and refurbishments of distribution assets include planned improvements and component replacements required to maintain operation of distribution lines and associated equipment. This consists mainly of betterment projects and system upgrades based on the asset age demographics and inspection results on asset condition in the community. These betterments include pole replacement and re-alignment, recloser maintenance, and switch replacement through attrition. Other minor equipment repairs are identified and actioned because of data collection process. Remotes also employs a run to failure strategy for its distribution transformers.

Diesel generators are maintained as per manufacturer-published recommendations including complete overhauls after specified hours. The decision to replace or refurbish a generator is based on economics. Medium-speed (1,800 rpm) units are rebuilt after 20,000 engine-hours, while low-speed (1,200 rpm) units are overhauled between 32,000 and 40,000 engine-hours. After two overhauls, it is no longer economical to refurbish the generator to achieve the desired reliability. Therefore, medium-speed generators are replaced after 60,000 engine-hours and low-speed generators are replaced between 96,000 and 120,000 engine-hours. Some units may be identified for earlier replacement based on specific issues and asset condition discovered during its lifecycle. Replacement may be advanced or lengthened accordingly. A diesel generator upgrade includes replacement of the auxiliary equipment and often, replacement of the GSUs and breakers based on an assessment of their age, condition, and available capacity. Other than when being replaced as part of a capacity upgrade project, GSUs are typically run to fail. Remotes keeps a spare transformer at each location to replace a transformer if it fails, however Remotes has never experienced a GSU failure to date.

5.3.3.2 Description of Maintenance and Inspection Practices

Remotes' maintenance programs are defined for each asset listed below. In addition to the asset-specific programs, Remotes performs routine maintenance and inspections of various aspects and elements of the generating station.

5.3.3.2.1 Daily Checks, Maintenance, Testing and Operations

Given the generator continuous running nature and moving parts; daily checks, maintenance, testing and operations play a vital role in Remotes' maintenance and inspection practices. Local, highly trained operators perform these functions for Remotes.

Operators perform detailed daily checks on all major assets and their associated components to ensure that everything is in sound operating condition. Examples include checking unit oil and coolant levels, reviewing alarms, checking fuel systems, and responding to trouble. Additional weekly duties include weekly fuel dips and reporting, and weekly maintenance call-ins. The local operators also perform regular oil changes and take the necessary samples for the oil and anti-freeze testing program. The operators are one of Remotes' most valuable assets as they are the first line of defence against major maintenance or failure.

5.3.3.2.2 Engines and Generators

Maintenance of engines and generators can be divided into planned and unplanned maintenance.

Planned maintenance of diesel generating units prevents premature equipment and system failures and contributes to service reliability. It includes all work performed on the diesel engine and associated generator in accordance with standard maintenance procedures as prescribed by the engine manufacturer. Intensive maintenance procedures are scheduled based on engine hours and vary from year to year. Inspections on engines are done every 5,000 hours.

Unplanned maintenance includes maintenance and repair of diesel generating units in response to trouble reports and equipment/component failures. The program may identify the need for repairs/component replacement that would not be accomplished in the planned maintenance program.

5.3.3.2.3 Tank Farms

Planned maintenance of tank farms and associated equipment includes regular inspections of all bulk fuel storage tanks, transfer pumps, control circuitry, piping and valves in the tank farm and the fuel delivery kiosk. This work helps prevent premature failures which could result in outages or spills and ensures the tank farm remains in working condition throughout its entire asset life. Tank farm inspections occur at all 19 stations. A review of outstanding fuel compliance audit findings is carried out to develop a long-term action plan. Corrective actions are undertaken on a planned basis to address significant tank and fuel system defects as identified.

Unplanned maintenance of tank farms is a response to tank farm and fuel system problems and includes repair work required to keep the generating station fuel offload, bulk storage tanks and fuel transfer equipment in standard operating condition.

Remotes regularly audits its fuel storage, fuel systems, fuel handling, and record keeping in each community for compliance with federal and provincial regulations as part of its ISO 14001 commitment. Regulations related to fuel systems, storage and handling, and record keeping are reviewed regularly, and changes are incorporated into compliance reviews/audits. The audits look for items such as training, pipe corrosion, protection of pipes from vehicles, fire safety, and supports for above-ground tanks. When areas of non-compliance are noted, capital improvements to meet regulatory standards are scheduled based on condition of the assets and severity of the defect. In 2016, Remotes invited representatives of the provincial regulatory authority, the Technical Standards and Safety Authority, to participate in these compliance review/audits to improve the quality of the audit process and its understanding of the regulatory requirements.

5.3.3.2.4 Facilities

Maintenance of facilities includes minor civil repair work required to maintain 19 generating station buildings, 16 staff houses, the Thunder Bay service center, fences, yards/sites which includes annual inspections, and annual sampling of water facilities for all staff houses and generating stations. Planned maintenance of facilities ensures they may be used for projected asset life without the need for major refurbishments.

5.3.3.2.5 REG Maintenance

REG maintenance includes inspection and repair of equipment at REG facilities (water powered) such as generating units and associated equipment. Maintenance is required to keep these stations and associated facilities in a standard operating condition. This primarily involves planned inspection and maintenance of the hydro-electric stations located at Deer Lake and Sultan. The yearly maintenance involves hydraulic system maintenance, gear box maintenance, generator maintenance, switchgear and control maintenance, and turbine checks.

Unplanned maintenance may also be performed in response to issues identified during routine station operation. This can include but is not limited to the repairs and modifications of the water intake and outflow facilities, the generator units and auxiliary equipment, generator gears, communications equipment, and the station building/site.

5.3.3.2.6 Auxiliary Systems

Maintenance work on generating station auxiliary equipment is required to keep them in standard operating condition. The work is performed based on the results of diagnostic tests such as coolant sample analysis along with normal cyclical maintenance as part of an annual inspection or with a major engine maintenance or overhaul procedure. Auxiliary equipment includes secondary heating, primary cooling, separate circuit and air-to-air aftercooling, exhaust, ventilation, overhead crane inspections, electrical, control, and fire protection systems. Auxiliary systems maintenance includes the main breaker cabinet, the station PLC, secondary heating, primary cooling, separate circuit and air-to-air aftercooling, ventilation, pump controls, overhead crane inspections, station air compressors, DC batteries, station service electrical equipment and fire protection systems, and all fuel system equipment and controls within the station.

5.3.3.2.7 GSUs

The GSUs do not require regular maintenance, but they are inspected annually for any potential problems. Remotes has not had a failure with a GSU at any of Remotes' 19 generating stations.

5.3.3.2.8 Distribution Assets

Maintenance on distribution assets ensures that the overall reliability of the distribution systems is maintained and improved, customer commitments are met, and all legislative and regulatory requirements are met. Data collected over past years identifies the required minor maintenance tasks in the communities.

Planned maintenance includes corrective and preventative line maintenance. The Distribution System Code requires that all local distribution companies patrol their distribution lines on a five-year cycle, to identify structural problems, damaged equipment, and components that may cause a power interruption. This also includes any hazards such as leaning poles, damaged equipment enclosures, and vandalism. Preventative maintenance includes maintenance that is primarily cyclical in nature as a means of reducing unplanned outages. Remotes has the unique benefit of very small radial feeds which are patrolled on a regular basis by local operators, by technicians when in the communities designing new connections, and by lines staff who work on these systems.

Vegetation management is an important element of reducing tree contact with energized lines which can cause the following adverse impacts:

- Interruption of power due to short circuit to ground or between phases
- Grass and brush fires
- Damage to conductors, hardware, and poles
- Danger to persons and property within the vicinity due to falling conductors, hardware, poles, and trees; and
- Danger of electric shock potential from electricity energizing vegetation.

One mitigating factor at Remotes is the shortened growing season in northern climates which typically limits the size and density of forestry impacts on the distribution system. However, regular and routine vegetation related maintenance is carried out by Remotes on an approximately 5-8 year cycle to further reduce adverse impacts. Remotes manages the program with the assistance of Hydro One Networks Forestry who also performs the work. Brushing activities are contracted to the local communities to generate employment and to enhance access to right of ways which ultimately has a positive impact on reliability.

Transport and Work Equipment (TWE) at Remotes gets extremely low utilization and therefore equipment with a lower cost of ownership (i.e., used equipment) are selected. This equipment is leased from Hydro One Networks who own, maintain and repair the equipment under a Service Level Agreement with Remotes. Due to the extreme costs and environmental impacts associated with equipment breakdowns, additional steps are being taken by Hydro One Networks in 2022 to enhance the maintenance cycles and quality of replacement parts such as hoses.

5.3.3.3 Processes and Tools to Forecast, Prioritize & Optimize System Renewal Spending

5.3.3.3.1 Forecasting

System renewal projects are discretionary in nature. The project needs for a particular period are supported by a multitude of factors, depending on the information available for each asset type. This could include a combination of asset inspection, individual asset performance, and condition information. Where available, manufacturer-published recommendations, asset's age, and routine maintenance and condition are also assessed with the intention of either extending the typical useful life where possible or reducing it where necessary. The inputs and processes used to forecast System Renewal spending is detailed further in Sections 5.3.1.3 and 5.3.1.4.

5.3.3.3.2 Prioritization

Remotes' generation and distribution assets are grouped into 15 different asset classes. These asset classes are then further allocated to one of three asset priority categories: Priority 1 (P1); Priority 2 (P2); and Priority 3 (P3). The priorities reflect the criticality of the asset class to the Remotes' system and include consideration of factors such as: public safety and employee health & safety, the importance of the asset to the sustained operation and reliability of Remotes' system, electricity security, new equipment procurement lead times, regulatory and environmental requirements, and economics.

P1 assets represent the highest priority assets and are of high value and high risk to the business, receiving proportionally more of the total sustainment program funds. P2 assets are next in priority and, although they include high-risk assets, these generally require comparatively moderate program funds. Finally, P3 assets are lowest in priority with low program funds and lower risk to the business. The allocation of the 15 asset classes into the three asset priority categories is shown in Table 5.3-13.

Table 5.3-13: Prioritization of Assets

Category	P1: High Priority	P2: Moderate Priority	P3: Low Priority
Generation	▪ Generation ▪ Station Transformers ▪ Fuel System & Fuel Inventory ▪ Land Assessment & Remediation	▪ Generation Circuit Breakers ▪ Protection & Control ▪ Oil Containment	▪ Generation Station Service (AC/DC)
Distribution	▪ Overhead Line Sections ▪ Wood Poles ▪ Distribution Transformers ▪ Right of Way Vegetation	▪ Switches & Fuses ▪ Distribution: Operating Transformer Spares	▪ Meters

5.3.3.3.3 Optimization

The continued performance of assets is managed through Remotes' capital investments and maintenance programs. Remotes' inspection, maintenance, and testing practices described previously in Section 5.3.3.2 support asset life cycle risk management by rectifying deficiencies to extend the lives of the assets and identifying the assets in the very worst condition for replacement.

5.3.3.3.4 Strategies for Operating within Budget Envelopes

The proposed distribution and generation system renewal projects and programs over the forecast period were paced for implementation based on system need, funding available for asset renewal and by taking into account customer preferences and the resources required for project implementation for the type of work predominantly involved. For Remotes, customer driven projects especially customer connections and generation upgrades always take priority.

Remotes completes investment planning on an annual basis to help inform any necessary budget adjustments for the following year. Remotes understands that circumstances may change, and if needed, budgets can be re-prioritized depending on customer and system needs. For example, due to the non-discretionary nature of system access projects, these projects will take priority in the event that there are competing demands with system renewal projects. Completing investment planning on an annual basis allows Remotes to use the best available information to effectively plan for and manage the highest priority projects and programs over the forecast period while remaining within the approved budget envelopes. The timing and urgency of ISC funded projects also influences budget envelopes.

5.3.3.3.5 Risks of Proceeding / Not Proceeding

System reliability and customer satisfaction is important to Remotes; therefore, it plans for any potential risks involved with not proceeding with individual capital expenditures and takes necessary steps to mitigate the risks. For example, most communities have 3 diesel generators, rated for different capacities to optimize fuel efficiency. In case of a generator outage, the other generators can be used to mitigate the effects of the next contingency if a lengthy repair is required. Remotes keeps a spare transformer at each community to mitigate the impact of an outage. If a transformer fails, the community experiences a power interruption until the power can be switched to the spare, which typically takes 4 hours.

Additionally, and as previously noted in Section 5.3.1.3, discretionary asset investments including system renewal investments are ranked against seven risk categories: customer/reliability, regulatory, financial, operational efficiency, environmental, safety, and reputation. The decision to delay or defer a project due to limited resources is made based on risk. The outcome of this process is a list of investments that is consistent with Remotes' strategic goals and considers levels of investment and associated risk mitigation.

5.3.3.4 Important Changes to Lifecycle Optimization Policies and Practices since Last DSP Filing

No changes have been made to Remotes' asset life optimization policies and processes since the last DSP filing. However, the Watay Project has introduced additional considerations as it relates to generation asset life optimization since 24/7 prime power from diesel generation may not be a key consideration in all communities. The Watay Project is expected to drastically change Remotes' business and operations during the forecast period and Remotes' lifecycle optimization policies and practices will continue to evolve with these changes.

5.3.4 System Capability Assessment for REG

Requests for renewable connections to both off-grid and on-grid communities are accommodated through the REINDEER program. There are two types of REINDEER projects: "Net Metering", and "Stand-Alone":

- "Stand-Alone" projects get paid for energy production according to a calculated rate per kilowatt generated. Available for grid-connected and non-grid connected communities.
- "Net Metering" projects will receive a reduced monthly bill, and in some situations a credit that expires after 12 months. Only available for non-grid connected communities.

The REINDEER program has been well received and very successful with many projects currently operating in Remotes' communities. With substantial energy saving benefits to all parties, Remotes plans to further promote this program in future years, and additional opportunities are expected over the next 3-10 years with the connection of Cat Lake and the six IPA communities and the on-going commitment to reduce GHG.

Currently there are no constraints on Remotes' distribution system that would prevent the connection of REG. Therefore, other than promotion of the program, Remotes does not anticipate any forecast costs to accommodate and connect REG facilities. Any costs for Remotes involvement in renewable projects are paid for by the proponent of the project.

5.3.5 CDM Activities to Address System Needs

A foundational element of Remotes' strategy is to improve community relations and customer service by offering programs that will help the remote communities build capacity to participate in the electrical industry and the economy as a whole.

5.3.5.1 Energy Conservation & Demand Management

Remotes' CDM programs aim to reduce the kWh usage in the communities as a means of managing system costs, reducing peak loads and improving the affordability of electricity bills for its customers. Remotes' CDM programs are specifically designed to reduce or maintain the overall community energy consumption, through both community and individual customer focus. The scope, nature and impact of the resulting programs are discussed below. Note that Remotes' programs are occasionally supplemented by programs aimed at First Nation communities managed by the IESO, federal programs or other stakeholders.

5.3.5.2 Utility Need & Customer Desire for CDM

Remotes is in a unique position as a utility as it relates to CDM: given the high costs to service isolated and remote communities, mainly by off-grid diesel as well as low subsidized rates, CDM savings often benefit both the customer and the utility. Energy costs for both grid and off-grid communities exceed residential rates which in-turn means that every kW saved through residential CDM lowers the RRRP subsidy required to operate the business. Most of Remotes' customers are economically disadvantaged and are low income. Unemployment is high and, for community members in the work force, most employment opportunities are part-time or seasonal. Compounding this fact is the geographic inaccessibility of the communities: gasoline, construction materials for homes, cars and groceries must all be transported over winter roads or by plane and make the cost of daily living very high. As such, most customers have very limited resources and are always interested in lower electricity bills so that basic needs can be met. The customer survey as well as the Customer Advisory Board point to the on-going desire for CDM, affordability programs and low rates

Given this geographic isolation, most communities themselves are also economically disadvantaged (with some buffering for communities that have revenue sharing agreements with mining operations on their traditional territory, or other business agreements). Communities and their leadership must continuously juggle competing community priorities with very limited resources; they are always interested in having lower electricity bills so that available funding can be redeployed to programs or infrastructure with a more direct benefit to community members. The recent First Nation Chief and Council leadership survey points to the on-going desire for CDM, affordability programs and low rates

5.3.5.3 Growth & Communication

In the rate decision of 2018 in response to OSLP desire for a new position to "promote available conservation, affordability and community programs in the 21 remote communities serviced by Remotes", a new role was created within Remotes: Community Relations & Customer Program Coordinator. The position was filled in November 2018, and since that time Remotes has been able to meet company program objectives more effectively, including promotion of energy conservation and affordability programs, program administration, as well as more effective direct and blanket communication with communities and customers. The following details communication modes as it relates to CDM:

- **In-person -** In-person meetings are a sure way to make direct connection with community leadership and customers, and Remotes continues to use face-to-face when feasible. As with many businesses over the past couple years through the COVID-19 pandemic, Remotes has had to widen its communication strategies as face-to-face meeting opportunities faded. Prior to the pandemic, Remotes would hold in-community meetings with presentations and information folders presented to leadership and/or customers several times a month. When in-person meetings have taken place, Remotes has a section in the power-point presentation on CDM programs, and all meetings have door-prizes and raffle draws that include CDM product giveaways including LED lightbulbs. Energy saving tips are also promoted, sometimes through innovative ways such as a community energy bingo or fun energy crowd-quizzes.
- **E-Bulletins -** Over the past few years Remotes' digital communication has grown. Remotes has utilized its customer database more robustly leading to a bi-weekly topical email Information Bulletin on programs, services, and energy conservation. This flexible mode enables targeted notices, for example, community program promotion to just Chief and councils or memos to just Ontario Works staff, as well as the capacity for instant wide-swath

announcements to all emails on file, for example, on energy tips for the winter. Remotes is working to expand its database to utilize this effective technique more fully.

- **Posters -** Posters hung in Band Offices, stores and highly visible locations continue to be a go-to method of getting CDM messages out to customers. Program and energy saving tips are both promoted.
- **Handouts -** There will always be value in paper handouts as a simple mode to present program and CDM information. Remotes has revamped and updated all program information and distributed consolidated folders to leadership of all communities either in-person, or through mail over the past 3 years. Translation of many handouts into Oji-Cree and Ojibway has been part of this important update. The handouts clearly lay out Remotes' customer programs, serve as a conversation starter and help to promote offerings and improve uptake.
- **Bill Inserts -** Remotes has a history of including information on CDM programs and energy tips inside of its newsletters and bill inserts. Its Customer Advisory Board, Chief and Council survey and Customer Survey have all confirmed that bill inserts are a good way to communicate with customers, and Remotes will continue the practice.
- **Online -** Remotes is in the process of enhancing its digital online presence from a single page on the larger Hydro One website, to its own, tailored webpage. Launch is planned for spring 2022. This will greatly assist in providing customers and communities relevant, timely, tailored content about Remotes, including CDM.

5.3.5.4 Programs over the Historical Period

The following CDM programs have been promoted over the past 5 years.

5.3.5.4.1 Energy Star Appliance Rebate Program

This program has been promoted for many years and bring awareness to the Energy Star rating system and the promotion of purchase of Energy Star Appliances to help curb energy use in the north and reduce customers electricity bills. The program is application-based and presents a mail-back rebate for any Energy Star Appliance purchased, for example, a $200 rebate for the purchase of a new Energy Star Refrigerator. The program can be accessed by individual customers, or by communities themselves, and essentially off-sets the slightly higher pricing of Energy Star Appliances.

- FOR INDIVIDUAL CUSTOMERS: The biggest limitation to customers taking advantage of this program is the availability of Energy Star Appliances in their local store(s) in remote fly-in communities. A targeted education effort to reach out to local store management about the program is in the works for 2022.
- FOR COMMUNITIES: There has been some success with the program at the Community level for new housing projects where large numbers of a variety of appliances are purchased by the Band, and multiple rebates may be received. Additional focus on the promotion of this program with community leadership and housing managers may help with increasing the uptake on this worthwhile program.

5.3.5.4.2 Commercial Lighting Retrofit Program

This Program was designed to assist Remotes in the upgrade of inefficient lighting systems to energy efficient LED (light-emitting diode) type lights in existing band-owned commercial buildings such as the arena, school, band office, hotel, restaurant, and community centres. Commercial buildings represent the largest energy users in the community. Changing over to energy efficient LED lights saves the community thousands of dollars in operating costs annually and saves Remotes the fuel costs associated with generating the electricity used to power those buildings, a win-win for everyone. At the conclusion of the project, a rebate is offered whereby Remotes covers 100% of the cost of replacement light fixtures and lamps for non-Standard A, and 50% of this cost for Standard A buildings.

As an example of successful implementation of the program, in 2021 North Caribou Lake First Nation participated in this program retrofitting the lighting in many of their band-owned buildings. One major building completed was the arena. The cost of this retrofit was approximately $14k, and as the building was General Service – three-phase rated, the rebate paid back to the band by Remotes was 100% of the cost of equipment. Annual energy use of the building was reduced by 62.49%, resulting in the project only taking 5.08 years to pay for itself in energy cost savings. The project details and results are shown in Table 5.3-14. This has been a popular program, with many communities to date participating.

Table 5.3-14 - North Caribou Lake Arena Commercial Lighting Retrofit

Cost of Equipment ($ '000)	Years Payback	Annual Energy Reduction (%)	Rate Type	Rebate %	Total Rebate ($ '000)
$14	5.08	62.49	General 1	100%	$14

5.3.5.4.3 Streetlight Retrofit Program

The Streetlight Retrofit Program has been a popular program for communities that already have streetlights; it gives financial incentive to upgrade old bulbs with new energy efficient, long lasting LED bulbs.

Remotes pays the community a Streetlight Retrofit Rebate of $250 for each streetlight upgraded to LED bulbs, which also save communities a substantial amount of money over the long term because they use much less energy and are more durable and longer lasting than older HPS style bulbs. As an example, the conversion of 50 streetlights from 150 kWh HPS bulbs to 88 kWh LEDs would save a community 3,100 kWh annually, which can be significant when facing load restrictions.

This has been a popular program, with many communities having participated in the program – there are only a couple communities currently served with HPS lights remaining to retrofit and Remotes will continue to promote this program where opportunities exist. In addition, Remotes is only offering LED streetlights for new installation and repair.

5.3.5.4.4 Top 20 Residential Energy User Pilot (2020)

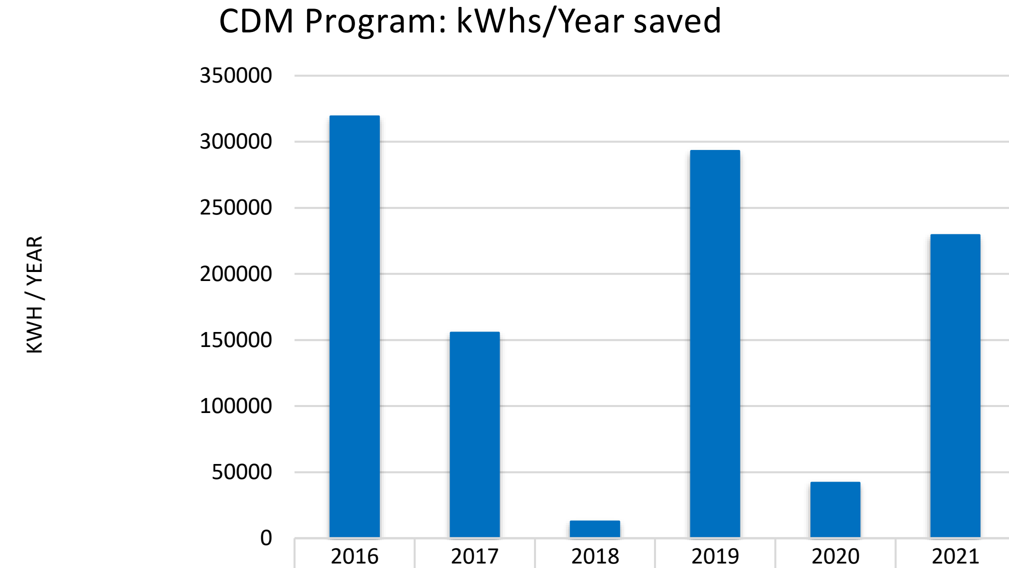
This pilot was run in the fall of 2020 and targeted the top 20 users of energy of all residential customers, shipping each home a robust energy saving kit consisting of: energy saving educational materials, LED lightbulbs, block heater timer, hot water tank blanket, various weatherstripping, spray foam sealant, shrink-wrap kit for windows, and a tap water aerator.

Feedback from the program participants was positive, and energy use in their homes was later analyzed to see if the energy kits assisted with reduction of their overall household energy consumption. Although it is impossible to draw definitive conclusions, assuming the energy kits were implemented in the fall of 2020, the data from January and February suggests substantial energy savings by the participating households. Outliers omitted, energy reduction in January, during the coldest and heaviest energy use month, was on average 8% lower post-pilot (2021 & 2022 average) for the program participants, compared to their pre-pilot energy usage (2019 & 2020 average). A similar program will likely be rerun in future.

5.3.5.5 Achievements

There have been many major CDM successes over the past 5 years including countless streetlights, building lighting retrofits, and Energy Star appliances purchased. This culmination of energy savings through Remotes' programs have helped grow energy independence, assist customers, and reduce or maintain load capacity within northern communities.

Table 5.3-10 below depicts the combined energy savings of all Remotes' CDM programs (except for REINDEER) and giveaways for the years 2016-2021. The amount of kWh savings shown are a combination of community participation in Commercial Lighting, Streetlight Retrofit CDM programs and Energy Star Program, as well as customer participation in the Energy Star Program and all of Remotes' CDM giveaways (LED lightbulbs, weatherstripping, block heater timers, etc.). The amounts shown are annual savings and will have lasting multi-year benefits. By example, each LED lightbulb change will not just save energy usage now but for likely a decade or more into the future.



	2016	2017	2018	2019	2020	2021
CDM Program: kWhs/Year saved	319146.6	155490	12750.3	293117.9	42056.5	229448.3

Figure 5.3-10: CDM Program Annual Energy Savings 2016-2021

Due to customer need, Remotes is planning on continuing to promote and invest in CDM programs. Given that the programs are customer driven, Remotes will continue to adapt to the ever-changing situation and support customers by offering options to reduce energy use. CDM programs or savings will aid in extending the life of generation assets and help reduce peak demand within communities. No CDM performance targets are set given the customer driven nature of the CDM program, and major capital investments in CDM are also not expected during the DSP plan period. Remotes will continue to require sufficient OM&A to effectively continue the CDM progress made through these programs and continue to meet Remotes' 2018 settlement conference commitment to promote energy conservation.

5.3.5.6 Future Plans & Outlook

Over the next two years, the Watay Project will continue to move northward and connect First Nation Communities in Northwestern Ontario to the provincial power grid. This has wide-ranging implications for Remotes, including CDM.

Servicing six new IPA communities presents a wonderful opportunity to offer Remotes' CDM programs to a couple thousand new customers with likely pent-up demand for participation in energy saving programs. The same applies to the communities themselves – Remotes anticipate many Streetlight

Retrofits Program applications and Commercial Lighting Retrofit applications from community leadership of these communities over the next 3-10 years.

Over the forecast period, CDM programs are expected to lead to some energy savings which will aid in extending the life of generation assets and help reduce peak demand within communities. This in turn could potentially defer the need for capacity upgrades or generator overhauls and/or replacements on a temporary, short-term basis. However, given that significant energy savings are unlikely, Remotes does not expect any material longer term deferrals to materialize over the DSP plan period as a result of CDM initiatives alone.

5.3.5.7 Internal CDM

It is important to encourage CDM not only to customers and communities, but also to find and implement energy efficiencies within Remotes' business. In striving to be a CDM leader internally, as well as externally, Remotes has completed many energy saving projects over the years.

5.3.5.7.1 Upgrades of Assets in Remote Communities

Remotes' local operations are supported by a Hydro One compound and its related infrastructure. Each of these compounds include a DGS, a house for crews to stay, main garages, storage and other outbuildings depending on the site. Over the past few years, Remotes has made great efforts to upgrade the locations with a goal of improving overall energy efficiency of the compound.

Crew housing improvements include:

- LED energy efficient lighting upgrades, both inside and out
- Heating system upgrades including waste heat from DGS
- New siding and insulation upgrades
- New energy efficient windows
- Purchase of Energy Star rated appliances
- Occupancy switches

DGS improvements include:

- LED energy efficient lighting upgrades, both inside and out
- New Siding, re-sheeting and insulation upgrades
- Use of variable speed drives for heating/cooling
- Use of secondary plant heat
- Use of waste heat for engine block heating
- Occupancy switches

5.3.5.7.2 Main Office Improvements

In addition to energy upgrades to Remotes' assets in remote communities, it has also continued to upgrade the main office building at 680 Beaverhall Place in Thunder Bay. Improvements include:

- LED energy efficient lighting upgrades, both inside and out
- Insulation upgrades
- Roof improvements
- Upgraded windows
- Heating systems efficiency upgrades
- Purchase of Energy Star rated appliances

5.4 Capital Expenditure Plan

This section summarizes Remotes' capital expenditure plan, which has been developed to meet Remotes' strategic corporate objectives. The capital expenditure plan was developed based on the planning and asset management processes previously described in Section 5.3.

5.4.1 Capital Expenditure Summary

The capital expenditure summary provides a snapshot of Remotes' capital and System O&M expenditures over the 2018 – 2027 DSP period. For summary purposes, capital investments are divided into the following investment categories based on the primary driver for the investment:

- System Access – Distribution
- System Renewal – Distribution
- System Service – Distribution
- System Renewal – Generation
- System Service – Generation
- General Plant

The breakdown of plan versus actuals over the historical period by investment category, is provided in Table 5.4-1, and the forecast costs broken down by investment category are provided in Table 5.4-2. Additional details can also be found in Appendix 2-AA and Appendix 2-AB.

Table 5.4-1: Historical Capital Expenditures and System O&M

Category	Historical												Bridge Year		
	2018			2019			2020			2021			2022		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Fcst.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access - Distribution															
Gross Capital Spend	897	1,015	13.2	1,065	1,548	45.4	1,121	1,195	6.6	1,143	2,059	80.1	1,166	2,762	136.9
Capital Contributions	(897)	(905)	0.9	(1,065)	(1,452)	36.3	(1,121)	(961)	(14.3)	(1,143)	(1,653)	44.6	(1,166)	(1,299)	11.4
Net Capital Expenditures	-	110	--	-	96	--	-	234	--	-	406	--	-	1,463	--
System Renewal -Distribution															
Gross Capital Spend	711	457	(35.7)	899	547	(39.2)	947	1,158	22.3	965	989	2.5	983	860	(12.5)
Capital Contributions	(243)	(260)	7.0	(290)	(151)	(47.9)	(304)	(819)	169.4	(311)	(578)	85.9	(313)	(238)	(24.0)
Net Capital Expenditures	468	197	(57.9)	609	396	(35.0)	643	339	(47.3)	654	411	(37.2)	670	622	(7.2)
System Service - Distribution															
Gross Capital Spend	-	5,861	--	-	557	--	-	-	--	-	-	--	-	-	--
Capital Contributions	-	(5,861)	--	-	(557)	--	-	-	--	-	-	--	-	-	--
Net Capital Expenditures	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--
System Renewal - Generation															
Gross Capital Spend	1,609	3,298	105.0	2,847	3,804	33.6	3,582	3,077	(14.1)	3,994	4,200	5.2	2,921	6,062	107.5
Capital Contributions	(130)	(260)	100.0	(211)	(592)	180.6	(213)	(324)	52.1	(204)	(830)	306.9	(205)	(473)	130.7
Net Capital Expenditures	1,479	3,038	105.4	2,636	3,212	21.9	3,369	2,753	(18.3)	3,790	3,370	(11.1)	2,716	5,589	105.8
System Service – Generation															
Gross Capital Spend	5,777	1,153	(80.0)	6,852	5,300	(22.7)	6,392	7,575	18.5	5,412	4,493	(17.0)	5,315	4,720	(11.2)
Capital Contributions	(5,323)	(789)	(85.2)	(6,126)	(5,152)	(15.9)	(5,717)	(7,298)	27.7	(5,021)	(4,235)	(15.7)	(4,962)	(4,603)	(7.2)
Net Capital Expenditures	454	364	(19.8)	726	148	(79.6)	675	277	(59.0)	391	258	(34.0)	353	117	(66.9)
General Plant															
Gross Capital Spend	509	183	(64.0)	572	136	(76.2)	581	147	(74.7)	590	1,178	99.7	598	998	66.9
Capital Contributions	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--
Net Capital Expenditures	509	183	(64.0)	572	136	(76.2)	581	147	(74.7)	590	1,178	99.7	598	998	66.9
Total Expenditure, Gross	**9,503**	**11,967**	**25.9**	**12,235**	**11,892**	**(2.8)**	**12,623**	**13,152**	**4.2**	**12,104**	**12,919**	**6.7**	**10,983**	**15,402**	**40.2**
Total Capital Contributions	**(6,593)**	**(8,075)**	**22.5**	**(7,692)**	**(7,904)**	**2.8**	**(7,355)**	**(9,402)**	**27.8**	**(6,679)**	**(7,296)**	**9.2**	**(6,646)**	**(6,613)**	**(0.5)**
Total Expenditure, Net	**2,910**	**3,894**	**33.8**	**4,543**	**3,988**	**(12.2)**	**5,268**	**3,750**	**(28.8)**	**5,425**	**5,623**	**3.6**	**4,337**	**8,789**	**102.7**
System O&M	21,343	19,607	(8.1)	23,888	21,087	(11.7)	25,291	21,185	(16.2)	25,790	20,606	(20.1)	26,053	22,533	(13.5)
Fuel	25,900	29,406	13.5	28,874	30,251	4.8	31,872	29,166	(8.5)	33,438	34,481	3.1	34,110	41,200	20.8
Other Power Supply Expenses	0	14	0	81	1,463	1706.2	85	1,779	1992.9	87	1,584	1720.7	90	2,795	3005.6
Watay Tx Connection Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	21,285	--
Total O&M	**47,243**	**49,028**	**3.8**	**52,843**	**52,802**	**(0.1)**	**57,248**	**52,131**	**(8.9)**	**59,315**	**56,671**	**(4.5)**	**60,253**	**87,814**	**45.7**

Table 5.4-2: Forecast Capital Expenditures and System O&M ($'000)

Category	Forecast				
	2023	2024	2025	2026	2027
System Access - Distribution					
Gross Capital Spend	5,168	3,980	1,812	1,844	1,877
Capital Contributions	(1,472)	(1,687)	(1,787)	(1,818)	(1,851)
Net Capital Expenditures	3,696	2,293	25	26	26
System Renewal - Distribution					
Gross Capital Spend	1,063	1,142	944	966	969
Capital Contributions	(265)	(283)	(267)	(272)	(277)
Net Capital Expenditures	798	859	677	694	692
System Service -Distribution					
Gross Capital Spend	-	-	-	-	-
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	-	-	-	-	-
System Renewal - Generation					
Gross Capital Spend	4,868	4,726	1,786	2,060	1,273
Capital Contributions	(1,116)	(1,138)	(19)	(25)	(34)
Net Capital Expenditures	3,752	3,588	1,767	2,035	1,239
System Service - Generation					
Gross Capital Spend	2,384	2,456	312	218	186
Capital Contributions	(2,089)	(2,105)	-	-	-
Net Capital Expenditures	295	351	312	218	186
General Plant					
Gross Capital Spend	2,050	556	552	560	560
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	2,050	556	552	560	560
Total Expenditures, Gross	**15,533**	**12,860**	**5,406**	**5,648**	**4,865**
Total Capital Contributions	**(4,942)**	**(5,213)**	**(2,073)**	**(2,115)**	**(2,162)**
Total Expenditures, Net	**10,591**	**7,647**	**3,333**	**3,533**	**2,703**
System O&M	22,050	22,246	23,314	23,443	22,925
Fuel	30,367	16,421	13,818	13,983	14,141
Other Power Supply Expenses	8,162	14,106	15,954	16,351	16,898
Watay Tx Connection Costs	66,000	103,695	103,695	103,695	103,695
Total O&M	**126,578**	**156,468**	**156,781**	**157,472**	**157,659**

5.4.1.1 Plan vs Actual Net Variances for the Historical Period

Assessing and understanding the variances is an important step for Remotes to promote continuous improvements in its estimation and budgeting process. The annual Remotes' capital and operation and maintenance work programs are subject to many different contributing factors beyond Remotes' control. This can result in large variances in the annual expenditures. Some of these factors include:

- **Uncertainty of ISC funding** - Funding for growth-related capital is mainly a federal responsibility. ISC faces funding constraints and both the timing for funding approvals and amounts of funding available are uncertain and require planning flexibility. ISC funding approvals may be determined in-year, after Remotes' business plan is approved. ISC design, approval and funding cycles are also lengthy and complex in nature. In response to customer needs to connect to the electrical system, Remotes adjusts its planned work program to accommodate upgrade projects.
- **Remote Community Accessibility** - Most of Remotes' communities are accessible only by air or winter roads. Due to the cost of air transportation, and to the size and weight of some of the equipment and materials required to perform work programs, winter roads are relied upon for transportation. If the appropriate weather conditions are not met in order to construct winter roads, it is not feasible to get the equipment and materials to site and therefore the work must be deferred.
- **Failures** - Remotes maintains its fleet of generators as guided by the original manufacturer. Sometimes a unit may fail unexpectedly. Responses to failures are initially treated as maintenance. To maintain the supply of power to customers in remote communities and to be prepared for the next system contingency in the community, all failures are treated as an emergency. Because of the minimal generation redundancy, the failure of a subsequent unit may lead to a community going dark. Without running generators, the community has no power, lights, or water (although some communities have backup generators at their water plants), and most buildings would have no heat. This situation can lead to an evacuation of the community and damage to critical community infrastructure.
- **Customer** - Whether generation or distribution in nature, Remotes strives to meet customer and community needs and commitments made to customers. Housing connections often delay betterments as crews are moved to more impactive customer work. Generation upgrades are critical to community development and well-being, so other generation projects are often deferred.

A breakdown of costs is provided in the following tables by each investment category for each historical year, and net variances that exceed +/- 10% are explained. Since a large portion of Remotes capital spending is also recovered via capital contributions and government funding, Remotes has also included high level explanations of variances for gross capital variances to provide the complete picture.

Table 5.4-3: Variance Explanations – 2018 Planned vs. Actuals

Category	2018			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access - Distribution	-	110	--	Timing of work and under recovery of fixed price work where bundling was not possible, and additional costs mainly travel were incurred to meet customer commitments.
System Renewal - Distribution	468	197	(57.9)	Re-prioritization of work as distribution staff were diverted to the Big Trout Lake/Wapekeka tie-line project.
System Service - Distribution	-	-	--	
System Renewal - Generation	1,479	3,038	105.4	Unplanned costs for replacement of the Marten Falls B unit.
System Service - Generation	454	364	(19.8)	SCADA and PLC replacements behind budget as staff was diverted to upgrade work.
General Plant	509	183	(64.0)	Re-prioritization of work relating to facilities projects as staff were diverted to upgrade work.
Total Expenditure, Net	2,910	3,892	33.7	
System O&M	21,343	19,608	(8.1)	
Fuel	25,900	29,406	13.5	Higher all-in delivered fuel price combined with higher volumes of fuel issued.
Other Power Supply Expenses				
Watay Tx Connection Costs	-	14	--	
Total O&M	47,243	49,028	3.8	

Table 5.4-4: Variance Explanations - 2019 Planned vs. Actuals

Category	2019			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access - Distribution	-	96	--	Timing of work and under recovery of fixed price work where bundling was not possible, and additional costs mainly travel were incurred to meet customer commitments.
System Renewal - Distribution	609	396	(35.0)	Re-prioritization of work as distribution staff were diverted to the completion of the Big Trout Lake/Wapekeka tie-line project.
System Service - Distribution	-	-	--	
System Renewal - Generation	2,636	3,212	21.9	Bearskin A unit and fuel tank replacements delayed and deferral due to lack of resources and focus on emergency work. However, this was offset by unplanned emergency engine replacements/rebuilds for Lansdowne A unit and Big Trout B unit, increased unit overhauls, as well as Wapekeka stack extensions and Gull Bay integration.
System Service - Generation	726	148	(79.6)	SCADA and PLC replacements behind budget as staff was diverted to emergency replacements and upgrade work.
General Plant	572	136	(76.2)	Re-prioritization of work relating to facilities projects as staff were diverted to upgrade work.
Total Expenditure, Net	4,543	3,988	(12.2)	
System O&M	23,888	21,088	(11.7)	Less spend on distribution programs and generation maintenance mainly auxiliary maintenance.
Fuel	28,874	30,251	4.8	
Other Power Supply Expenses	81	1,463	1706.2	Increase relates to the addition of Pikangikum
Watay Tx Connection Costs	-	-	--	
Total O&M	52,843	52,803	(0.1)	

Table 5.4-5: Variance Explanations – 2020 Planned vs. Actuals

Category	2020 Plan. ($ '000)	2020 Act. ($ '000)	2020 Var. (%)	Variance Explanations
System Access - Distribution	-	234	--	Timing of work and under recovery of fixed price work where bundling was not possible, and additional costs mainly travel were incurred to meet customer commitments.
System Renewal - Distribution	643	339	(47.3)	Distribution resources were allocated to larger, unexpected customer-driven fully recoverable distribution capital improvement projects.
System Service - Distribution	-	-	--	
System Renewal - Generation	3,369	2,753	(18.3)	Increased engine overhauls and unplanned emergency overhaul for Sandy Lake. However, this budget increase was offset by a delay in the Big Trout Tank farm work and unit replacement.
System Service - Generation	675	277	(59.0)	Big Trout Tank farm work and unit replacement has been delayed or deferred.
General Plant	581	147	(74.7)	Deferral of non-essential facilities projects due to COVID-19.
Total Expenditure, Net	5,268	3,750	(28.8)	
System O&M	25,291	21,186	(16.2)	Less spend on programs due to the impact of COVID-19.
Fuel	31,872	29,166	(8.5)	
Other Power Supply Expenses	85	1,779	1992.9	Increase relates to the addition of Pikangikum
Watay Tx Connection Costs	-	-	--	
Total O&M	57,248	52,131	(8.9)	

Table 5.4-6: Variance Explanations – 2021 Planned vs. Actuals

Category	2021 Plan. ($ '000)	2021 Act. ($ '000)	2021 Var. (%)	Variance Explanations
System Access - Distribution	-	406	--	Timing of work and under recovery of fixed price work where bundling was not possible, and additional costs mainly travel were incurred to meet customer commitments. Wholesale metering cluster for grid connection not anticipated for.
System Renewal - Distribution	654	411	(37.2)	Distribution resources were allocated to larger, unexpected customer-driven fully recoverable distribution capital improvement projects.
System Service - Distribution	-	-	--	
System Renewal - Generation	3,790	3,370	(11.1)	Deer Lake C Unit engine replacement and increased engine overhauls. However, this increase was offset by the deferral of the Big Trout Lake bulk fuel tank.
System Service - Generation	391	258	(34.0)	SCADA and PLC replacements behind budget as staff was diverted to upgrade work and other projects.
General Plant	590	1,178	99.7	Construction of delayed projects including Wapekeka staff house and lines storage shed in Big Trout Lake.
Total Expenditure, Net	5,425	5,623	3.6	
System O&M	25,790	20,606	(20.1)	Less spend on programs due to the impact of COVID-19.
Fuel	33,438	34,481	3.1	
Other Power Supply Expenses	87	1,584	1720.7	Increase relates to the addition of Pikangikum
Watay Tx Connection Costs	-	-	--	
Total O&M	59,315	56,671	(4.5)	

Table 5.4-7: Variance Explanations - 2022 Planned vs. Forecast

Category	2022 Plan. ($ '000)	2022 Fcst. ($ '000)	2022 Var. (%)	Variance Explanations
System Access - Distribution	-	1,463	--	Wholesale metering cluster for grid connection not anticipated for.
System Renewal - Distribution	670	622	(7.2)	
System Service - Distribution	-	-	--	
System Renewal - Generation	2,716	5,589	105.8	Biscotasing bulk tank replacement deferred, but this was offset by the previously deferred Big Trout A unit replacement required for safety concerns and to ensure reliable backup power.
System Service - Generation	353	117	(66.9)	SCADA and PLC replacements behind budget as staff was diverted to upgrade work and other projects.
General Plant	598	998	66.9	Anticipated office expansion or relocation costs not budgeted for.
Total Expenditure, Net	4,337	8,789	102.7	
System O&M	26,053	22,534	(13.5)	Less spend on generation maintenance due to connection to the grid for certain communities.
Fuel	34,110	41,200	20.8	Higher all-in delivered fuel price combined with higher volumes of fuel issued.
Other Power Supply Expenses	90	2,795	3005.6	Increase relates to the addition of Pikangikum
Watay Tx Connection Costs	-	21,285	--	Watay fixed transmission costs
Total O&M	60,253	87,814	45.7	Impact of increased fuel costs and Watay fixed transmission costs

5.4.1.2 Variance Explanations – Gross Capital

Unlike other utilities, Remotes receive significant amount of funding contribution indirectly from ISC and the communities it serves. As shown in Table 5.4-8, the percentage of contributions and removals can range anywhere from 30% to over 70% of gross capital in any given year.

Table 5.4-8: Capital Overview – Gross, Contributions & Net Capital ($ '000)

Category	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Budget	2023 Budget	2024 Budget	2025 Budget	2026 Budget	2027 Budget
Total Capital Expenditure, Gross	11,967	11,892	13,152	12,919	15,402	15,533	12,860	5,406	5,648	4,865
Contributions & Removals	(8,075)	(7,904)	(9,402)	(7,296)	(6,613)	(4,942)	(5,213)	(2,073)	(2,115)	(2,162)
Total Capital Expenditure, Net	3,892	3,988	3,750	5,623	8,789	10,591	7,647	3,333	3,533	2,703
% of Contributions & Removals	67.5%	66.5%	71.5%	56.5%	42.9%	31.8%	40.5%	38.4%	37.5%	44.4%

Gross expenditures mostly reflect the recoverable upgrade projects funded indirectly by ISC. The funds received are of a somewhat ad-hoc nature; however, the customer related projects take priority in the work planning and execution streams since they alleviate connection restrictions thus allowing community growth. Finding workable solutions for Remotes, ISC and the First Nation often takes time to resolve so there is limited project certainty in both timing and amounts. As well, given approximately

90% of Remotes' customers are First Nation and on-reserve, government programs such as housing, water treatment and education initiatives can drastically alter the current and future energy use within the communities.

Generation upgrades often represent a significant use of Remotes' resources during a given year often making gross capital a more comprehensive view of Remotes' business and total work plan. Given limited staffing resources and logistical, housing, flight, facility constraints, Remotes often needs to shuffle staff and crews between types of work. Non-urgent maintenance is often deferred as well as internal capital projects to accommodate.

Remotes strongly appreciates ISC's joint commitment of providing safe, reliable, affordable power to Remotes' communities. Some of the project highlights over the historical period include: Big Trout Lake/Wapekeka Tie-line (Distribution), and generation upgrades in Wapekeka, Sandy Lake, Marten Falls, and Sachigo.

5.4.1.3 Forecast Capital Expenditures

The following table summarizes the planned capital expenditures, by investment category, throughout the DSP forecast timeline. The following sub-sections describe the planned capital expenditures in more detail.

Table 5.4-9: Forecast Net Capital Expenditure Summary

Category	Forecast					Total ($ '000)	Percent of Total
	2023	2024	2025	2026	2027		
	$ '000	$ '000	$ '000	$ '000	$ '000		
System Access – Distribution	3,696	2,293	25	26	26	6,066	21.8%
System Renewal – Distribution	798	859	677	694	692	3,720	13.4%
System Service -Distribution	-	-	-	-	-	-	0.0%
System Renewal – Generation	3,752	3,588	1,767	2,035	1,239	12,381	44.5%
System Service - Generation	295	351	312	218	186	1,362	4.9%
General Plant	2,050	556	552	560	560	4,278	15.4%
Total Expenditure, Net	**10,591**	**7,647**	**3,333**	**3,533**	**2,703**	**27,807**	**100.0%**

5.4.1.3.1 System Access – Distribution

Expenditures within the system access category are largely driven by customer service requests for new connections and/or service upgrades, and mandated service obligations. The timing of investments in this category are driven by the needs of external parties and are considered mandatory. The work performed under this category is also largely recoverable from the requesting parties or from government funding. Investments in system access are captured in the table below.

Table 5.4-10: Forecasted Distribution System Access Investments ($'000)

Category	Forecast				
	2023	2024	2025	2026	2027
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access – Distribution, Gross	5,168	3,980	1,812	1,844	1,877
Capital Contributions	(1,472)	(1,687)	(1,787)	(1,818)	(1,851)
Total Expenditure, Net	**3,696**	**2,293**	**25**	**26**	**26**

Net system access investments normally represent a small portion of Remotes' overall net capital spending because these expenditures are largely funded through capital contributions. However, for this forecast period, system access investments represent 21.8% of Remotes' overall forecast spending which is largely as a result of the one-time increase in non-recoverable spend between 2022-2024 relating to the wholesale metering cluster compound design and construction for the communities connecting to the grid as part of the Watay Project. This one-time increase is a mandatory investment that is driven by IESO requirements and the Watay Project. Additional information on this project can be found in Appendix A under the "Watay Grid Connection 4-Pole Cluster" Material Investment Narrative.

5.4.1.3.2 System Renewal – Distribution

Capital investments under distribution system renewal are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety, and sustainment of Remotes' distribution systems. Investments in distribution system renewal are captured in the table below.

Table 5.4-11: Forecasted Distribution System Renewal Investments ($'000)

Category	**Forecast**				
	2023	**2024**	**2025**	**2026**	**2027**
	$ '000	**$ '000**	**$ '000**	**$ '000**	**$ '000**
System Renewal – Distribution, Gross	1,063	1,142	944	966	969
Capital Contributions	(265)	(283)	(267)	(272)	(277)
Total Expenditure, Net	**798**	**859**	**677**	**694**	**692**

Distribution system renewal investments represent 13.4% of Remotes' budgeted net capital expenditures over the forecast period. A large portion of this spending falls under Distribution System Improvements which includes replacements of aging or defective poles, conductor restringing, and pole re-alignments based on the asset condition surveys in the community.

Distribution system capital improvements are made in 1-2 communities per year – depending on the size of the community – along with minor betterment projects in other communities. Betterments and system upgrades are made to facilitate system reliability and joint use of poles. New Viper switches, which allow on-site operator response are also installed based on the power system reliability in the community.

Other distribution system capital investment in this category includes defective meter replacements, minor storm damage repair, damage claims, and small external demand requests. Storm damage repairs mainly depend on severe weather occurrences such as lightning, wind, and ice storms. Damage claims work entails repairs to equipment resulting from damaged caused by members of the public.

For the forecast year, Remotes is expecting a short-term increase in metering costs as Remotes replaces meters in newly acquired service areas. The increased metering costs have been budgeted based on the anticipated service area additions and increased customer count. However, the planned increase in spending on programs under this category over the forecast period is modest. The number of distribution assets under management by Remotes is also expected to increase over the forecast period when new communities are added to the service area, however no major increase in distribution system renewal spending has been planned since ISC is funding major asset upgrades to the distribution lines before they are transferred to Remotes.

5.4.1.3.3 System Service – Distribution

Distribution system service investments generally enhance the quality and reliability of the distribution system to meet operational objectives and address future electricity service requirements. Remotes is not expecting any distribution system service expenditures over the forecast period since there are no expected load changes that will constrain the ability of the system to provide consistent service delivery.

5.4.1.3.4 System Renewal – Generation

Generation system renewal investments contribute to the management of Remotes' generation units and are mostly driven by the condition and operating hours of the units. Investments under this category includes the overhauling and replacement of generator units. Investments in generation system renewal are captured in the table below.

Table 5.4-12: Forecasted Generation System Renewal Investments ($'000)

Category	Forecast				
	2023	2024	2025	2026	2027
	$ '000	$ '000	$ '000	$ '000	$ '000
System Renewal – Generation, Gross	4,868	4,726	1,786	2,060	1,273
Capital Contributions	(1,116)	(1,138)	(19)	(25)	(34)
Total Expenditure, Net	**3,752**	**3,588**	**1,767**	**2,035**	**1,239**

Generation system renewal spending for the management of Remotes' 60 generator units accounts for 44.5% of Remotes' budgeted net capital expenditures over the forecast period. These include overhauling and replacement of generator units, generating station civil improvements based on the condition of the foundations and structures as determined through inspections, and day and bulk tank replacements as planned based on the need to replace end-of-life fuel tanks determined by condition and compliance. Material projects planned for the 2023 Test Year include replacement of the Armstrong A & B units, the Big Trout Lake A unit, and the Lansdowne House C unit, as well as the replacement of two bulk tanks at the Lansdowne House DGS. Additional information on these projects can be found in Appendix A.

Generation system renewal spending is expected to drop significantly in the 2025-2027 period once many of Remotes' communities are connected to the grid and generator operating hours drop dramatically.

5.4.1.3.5 System Service – Generation

Capital investments under the generation system service category are primarily aimed at upgrade projects, which are driven by capacity requirements and are largely recoverable through ISC and community funding. Investments in generation system service are captured in the table below.

Table 5.4-13: Forecasted Generation System Service Investments ($'000)

Category	Forecast				
	2023	2024	2025	2026	2027
	$ '000	$ '000	$ '000	$ '000	$ '000
System Service – Generation, Gross	2,384	2,456	312	218	186
Capital Contributions	(2,089)	(2,105)	-	-	-
Total Expenditure, Net	**295**	**351**	**312**	**218**	**186**

Generation programs in this category make up a significant portion of Remotes' gross capital expenditures, but many of these projects are funded externally. As a result, the spending in this category represents only 4.9% of Remotes' budgeted net capital expenditures over the forecast period.

The Gull Bay DGS Upgrade and the Lansdowne House DGS Upgrade projects are two key upgrade projects planned over the forecast period which are required to support the continued growth and development of the communities they serve. Since these upgrade projects are driven by capacity requirements, they are 100% recoverable through ISC and community funding. Additional information on these projects can be found in Appendix A.

Remotes is also planning to continue improving its SCADA and PLC systems over the forecast period by upgrading communication systems that will allow for more efficient remote troubleshooting and reliable download of data to the SCADA server.

5.4.1.3.6 General Plant

General plant investments are modifications, replacements, or additions to Remotes' assets that are not part of its distribution or generation system. Investments in generation system service are captured in the table below.

Table 5.4-14: Forecasted General Plant Investments ($'000)

Category	Forecast				
	2023	2024	2025	2026	2027
	$ '000	$ '000	$ '000	$ '000	$ '000
General Plant, Gross	2,050	556	552	560	560
Capital Contributions	-	-	-	-	-
Total Expenditure, Net	**2,050**	**556**	**552**	**560**	**560**

General plant investments represent 15.4% of Remotes' budgeted net capital expenditures over the forecast period. These investments include life extension of staff housing in each community driven by the condition of the lodging, investments into storage buildings and other miscellaneous civil projects based on the need to have a suitable location that is large enough to store, and maintenance of large equipment such as backhoes and Radial Boom Derricks (RBDs). Also included in the forecast period is the expansion/relocation of the Beaverhall Facility in 2022-2023 to accommodate the growing workforce anticipated to occur with the added operational complexity, and additional communities that Remotes will be servicing. Additional information on this project can be found in Appendix A.

5.4.1.4 Investments with Project Lifecycle Greater than One Year

Construction costs, and any related interest, for a capital project are included in construction in progress (i.e., Asset Under Construction (AUC)). At this point no capitalization takes place. Recognition of capital costs for a project ceases (including the capitalization of interest) when substantially all construction, acquisition or development are completed and the project is in the location and condition necessary for it to be operating in the manner intended, which is generally attained at the in-service date of the capital project. The in-service date is also the point at which Remotes begins to record depreciation expense and ceases capitalizing interest costs. In general, most distribution and generation work is completed and capitalized in the same year. Longer term, fully recoverable generation upgrades, often span multiple years before being placed into service and capitalized.

5.4.1.5 Comparison of Forecast and Historical Expenditures

A comparison of Remotes' net capital expenditures in the DSP's forecast period as compared to the historical period is provided in the following sub-sections.

5.4.1.5.1 Overall Capital Expenditures

With the increase in community connection projects and one-time costs associated with the Watay Project, the average overall capital expenditures forecast is approximately 7% greater than the historical plus bridge year average (Figure 5.4-1).

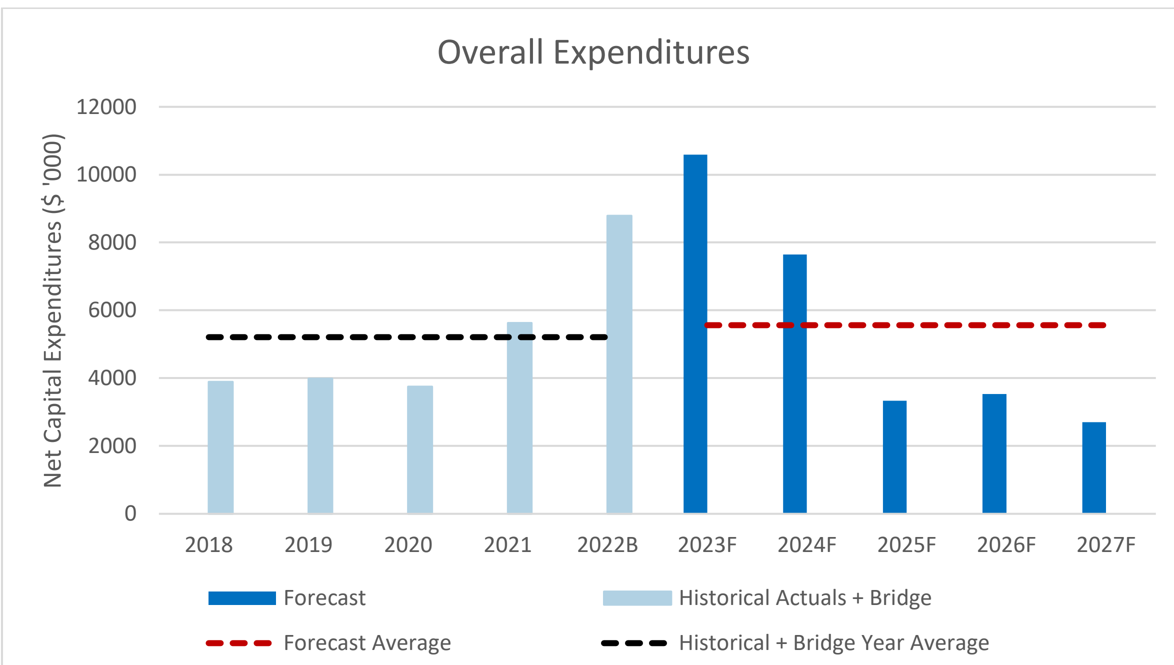


Figure 5.4-1: Overall Comparative Expenditures

5.4.1.5.2 System Access – Distribution

The historical system access trend is variable year over year due to the unpredictability of customer connection service requests and other external factors. As shown in Figure 5.4-2, Remotes' distribution system access forecast average expenditures are approximately 163% greater than the historical plus bridge year average. This is explained by the IESO driven one-time increased non-recoverable spend in 2022-2024 relating to the wholesale metering cluster compound design and construction for communities connecting to the grid.

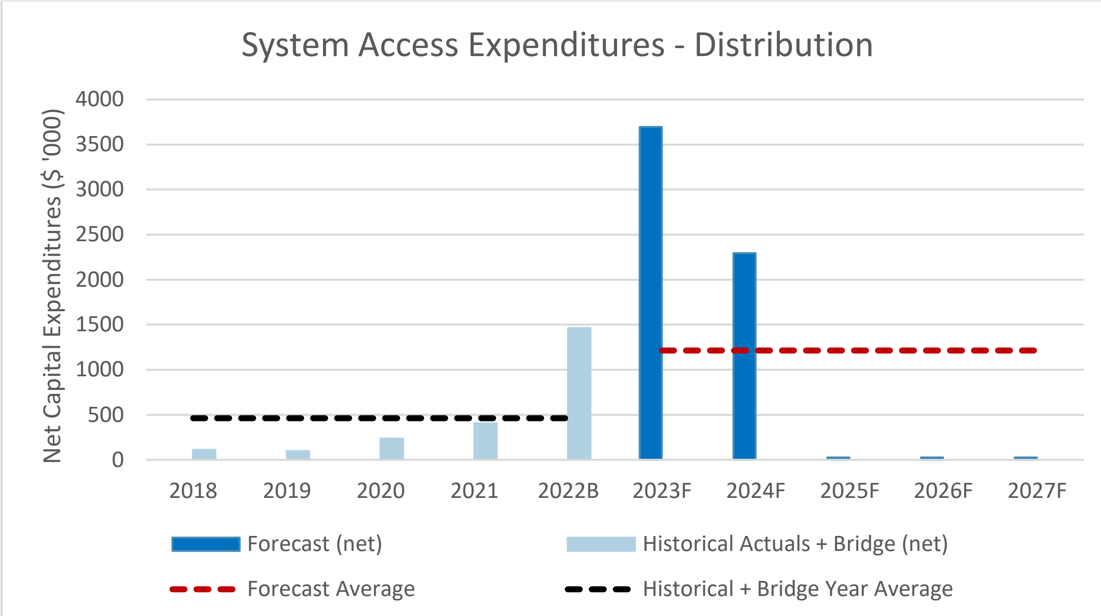


Figure 5.4-2: Distribution System Access Comparative Expenditures

5.4.1.5.3 System Renewal – Distribution

Distribution system renewal expenditures are impacted by planned capital investments and the objective to address any condition-based maintenance activities within the asset system to meet customer's expected performance and reliability. As shown in Figure 5.4-3, the forecast average for distribution system renewal is approximately 89% greater than the historical plus bridge year average. This is due to increased metering and other distribution system costs expected to be incurred with the addition of new communities to the service area and increased customer counts.

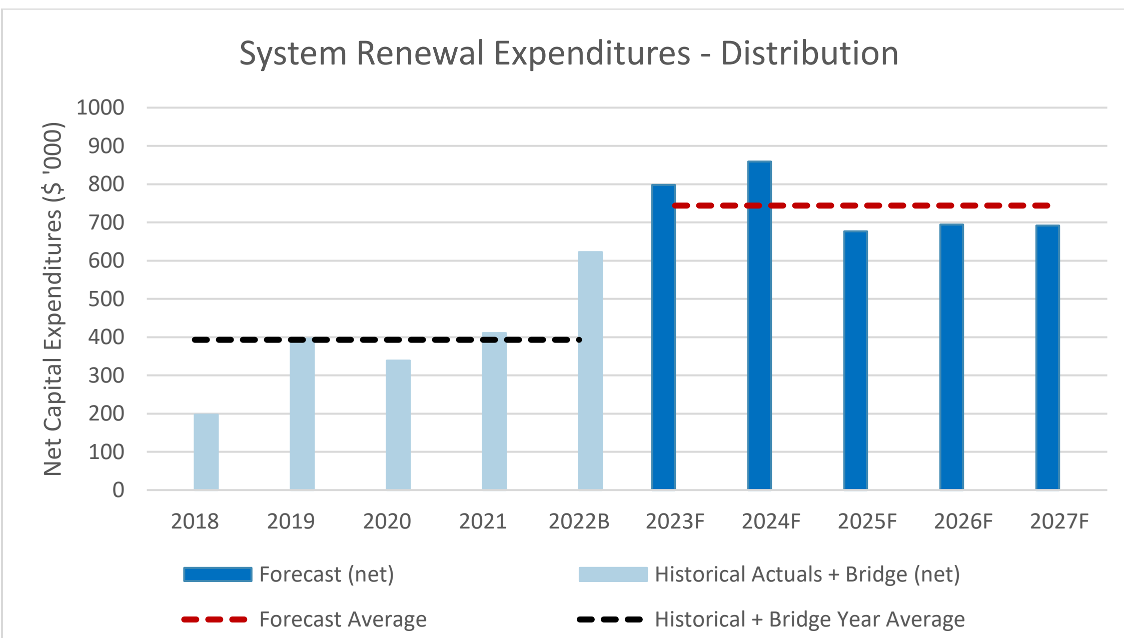


Figure 5.4-3: Distribution System Renewal Comparative Expenditures

5.4.1.5.4 System Service – Distribution

In 2018 and 2019, Remotes connected KI and Wapekeka via the Tie-line project, which was a one-time event that was fully recoverable. Remotes is not expecting any distribution system service expenditures over the forecast period.

5.4.1.5.5 System Renewal – Generation

Generation programs in the system renewal category are largely driven by condition of generation assets. As shown in Figure 5.4-4, the generation system renewal forecast spending is approximately 31% lower than the historical plus bridge year average. This is because starting in 2025, the spending drops significantly once many of the Remotes' communities are connected to the grid and the generator operating hours are significantly reduced as they are expected to operate as backup only.

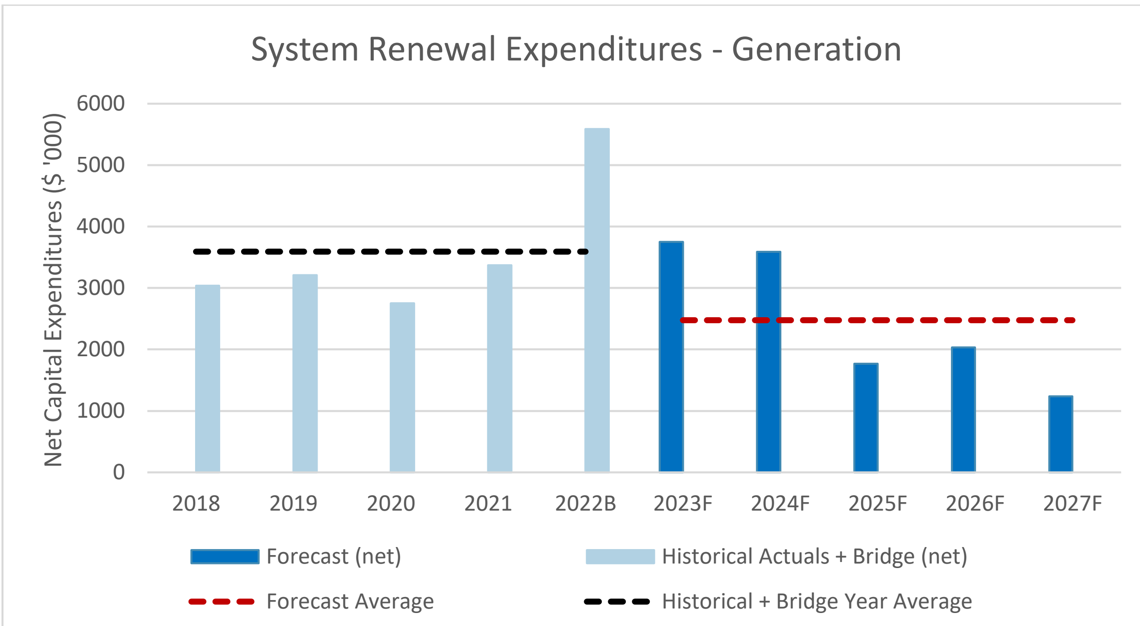


Figure 5.4-4: Generation System Renewal Comparative Expenditures

5.4.1.5.6 System Service – Generation

Generation programs in the system service category make up a significant portion of Remotes' gross capital expenditures, but many of these projects are fully recoverable. As shown in Figure 5.4-5, the non-recoverable generation system service forecast average spending is approximately 17% greater than the historical plus bridge year average. This is mainly due to investments in SCADA and PLC upgrades over the forecast period.

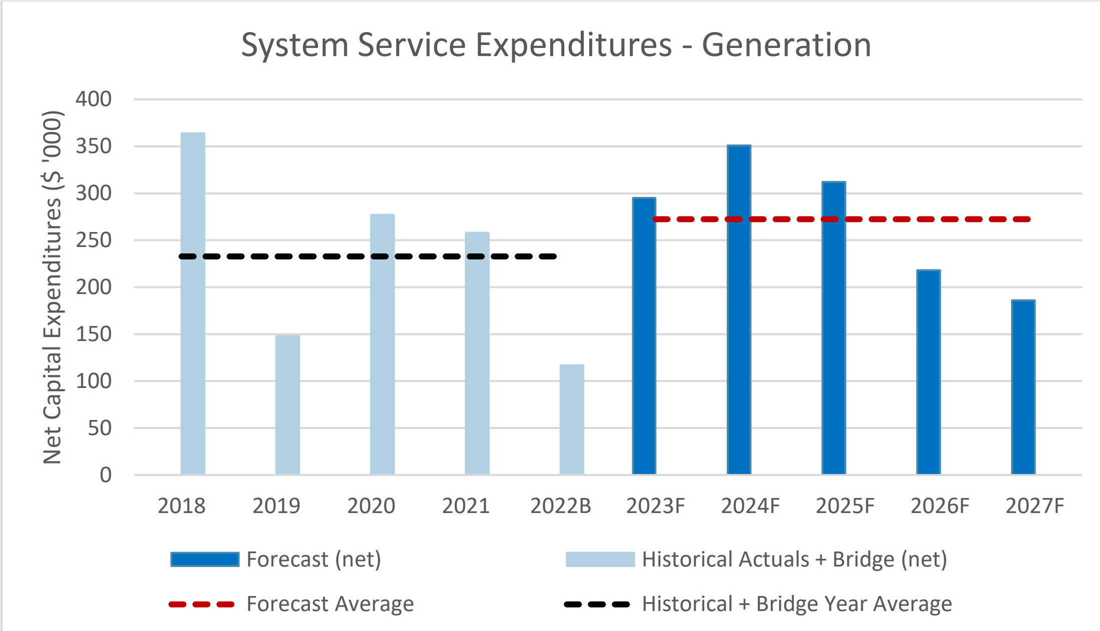


Figure 5.4-5: Generation System Service Comparative Expenditures

5.4.1.5.7 General Plant

As shown in Figure 5.4-6, the forecast average for general plant is approximately 62% higher than the historical plus bridge year average. This is primarily due to the expansion / relocation of the Beaverhall Facility in 2022-2023 to accommodate the anticipated growth in workforce and space requirements associated with the Watay Project, growing business complexity and the addition of the seven new communities to Remotes' customer base (six grid-connected IPA communities plus Cat Lake).

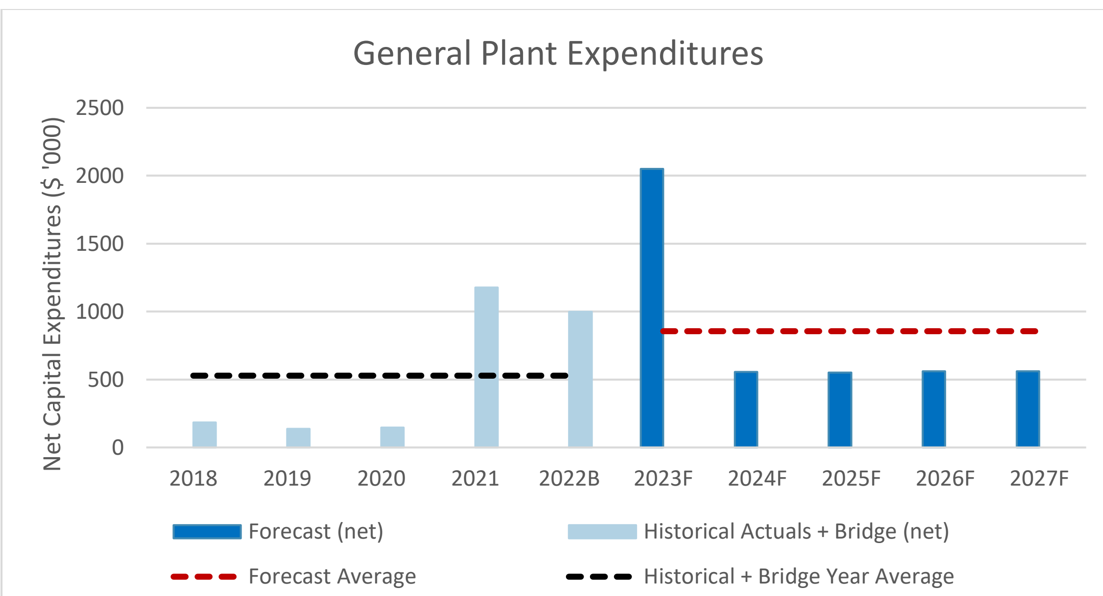


Figure 5.4-6: General Plant Comparative Expenditures

5.4.1.6 Forecast Impact of System Investments on System O&M Costs

Table 5.4-15 summarizes the forecast system O&M and total O&M including fuel and cost of power. System O&M spending is broken down into 5 categories: distribution, generation, common (i.e., northern strategies, community relations and common facilities), environment (e.g., waste management, spill management and monitoring, incident follow-up, environmental management system implementation) and other O&M (i.e., shared services).

Table 5.4-15: Forecast O&M Expenditures

Category	Forecast				
	2023	2024	2025	2026	2027
	$ '000	$ '000	$ '000	$ '000	$ '000
Distribution O&M	6,295	6,548	7,056	7,734	6,811
Generation O&M	11,378	11,000	11,062	10,484	10,702
Common O&M	1,531	1,700	1,754	1,785	1,886
Environment O&M	1,196	1,216	1,238	1,256	1,278
Shared Services, Other O&M	1,641	1,782	2,204	2,184	2,248
System O&M	**22,041**	**22,246**	**23,314**	**23,443**	**22,925**
Fuel	30,365	16,421	13,818	13,983	14,141
Other Power Supply Expenses	8,162	14,106	15,954	16,351	16,898
Watay Tx Connection Costs	66,000	103,695	103,695	103,695	103,695
Total O&M	**126,568**	**156,468**	**156,781**	**157,472**	**157,659**

Remotes investigated the relationship between capital spending and system O&M costs. Regardless of the capital spending, generator maintenance is required every 2,500 engine-hours. Due to the associated flight and fuel costs of this maintenance, there is no reduction to system O&M costs from capital investment. Over the forecast period, the overall distribution O&M is expected to grow slightly, but this will be offset by reduced generation O&M as communities become grid connected.

Generation activities will decrease overall due to less planned and unplanned unit maintenance and operation costs attributed to reduced prime power running hours. Other generation maintenance such as buildings and tanks will remain largely unchanged as the need still exists for back-up power operations. Additionally, the six IPA communities will add new costs as additional generation assets are being maintained.

Fuel for electrical generation will decrease over the DSP plan period as communities move away from diesel generation and are connected to the Watay grid, which is planned to be completed by 2024. Cost of Power will continue to grow over the DSP plan period as customer energy needs will be met through grid connection. The Watay Tx connection costs are also expected to grow as more communities get connected.

Additional detail on O&M expenditures can be found in Exhibit D of Remotes' COS Application.

5.4.1.7 Non-Distribution Activities

Since Remotes both generates and distributes electricity, forecast expenditures include investments in both distribution and generation related activities.

5.4.2 Justifying Capital Expenditures

Customer Value

As a small business, Remotes understands its customers and works closely with them. As previously discussed in Section 5.2.2.1, Remotes regularly communicates and meets with customers throughout the year and, in First Nations communities, works closely with Band Councils to help them meet community electricity needs and preferences. Remotes also understands that the cost of living in the north is high and dedicates significant efforts to keep monthly bills affordable.

As noted in Section 5.3.1.1, Remotes has a number of customer-centric AM objectives, including:

- Ensure the effective development of modern, reliable, cost- effective, safe, efficient and flexible systems which are customer-oriented and meets customers' needs.
- Leverage effective and innovative ways and means to meet the needs of customers, including customer choice and the enablement of value services to the customers.
- Ensure long-term sustainability of existing assets and equipment; system reliability and security; and customer satisfaction and environmental integrity.

These key objectives drive Remotes' planning and AM processes and customer feedback is a key input considered when developing capital plans.

By prioritizing the system access projects, including new customer connections and service requests, as mandatory, Remotes ensures that customer needs and requests are being met. Additionally, by implementing the generator upgrade projects, including the Gull Bay (KZA) DGS Upgrade and the Lansdowne House (Neskantaga) DGS Upgrade, Remotes is ensuring that customers within these communities will be able to make new connections to the distribution system to add more housing and supply new critical infrastructure projects within the community. These upgrades are also consistent with ensuring customers' expectations for unrestricted connection to the distribution system.

Remotes' proposed distribution and generation system renewal projects, including the replacement of poor condition generation units that are near or beyond 60,000 operating hours, are prioritized based on different risk categories, and the resulting projects and programs are selected to ensure continued delivery of safe and reliable electricity to communities for years to come. Customer preferences, including the desire for reliable and safe electricity at a reasonable price, are also taken into consideration when optimizing, prioritizing, and pacing these expenditures. Remotes general plant investments are also selected and prioritized such that Remotes can continue to operate safely, efficiently and support other work.

Finally, by participating in, and advocating for the Watay Project, Remotes is working towards a large fuel cost reduction, much lower emissions and reduced capital and OM&A expenditures on diesel plants, and a more flexible power solution for its customers.

Technological Changes and Innovation

Innovation is part of Remotes' AM objectives, which align with Remotes' corporate mission and vision. Where possible, Remotes investigates and leverages innovative ways to improve asset and system performance, operations, and maintenance to meet the needs of customers and demonstrate leadership in technology advancement. A few examples of technological improvements and innovation planned over the forecast period include:

- SCADA communication upgrades planned over the forecast period will result in improved remote access to several generating station SCADA systems from the Remotes Service

Center. The improved communications will improve remote troubleshooting and allow for more reliable download of data to the SCADA server. Additionally, antiquated Human-Machine Interface (HMI) interfaces at some stations will be replaced with modern desktop computers to enable operators and maintenance personnel to more easily interact with the station control system.

- Due to the continuous improvement of generator technology, new diesel generators installed in the field (whether as part of replacement or upgrade projects) have higher efficiency than the older models they replace, thereby reducing the fuel costs to operate the generator. Remotes uses automatic generator dispatch to optimize the efficiency of its fuel consumption.
- Remotes is proposing to replace the existing Big Trout Lake DGS with a modular generation station. Although this may not be innovative for other utilities and mines that use diesel generators for prime power, the move to a modular generating station is novel for Remotes. Modular stations have been proven by others to be a suitable alternative to traditional DGS, and in the case of the Big Trout Lake DGS, the move to a modular station represents a cost-effective way to address the safety and environmental issues at the existing end of life DGS while also providing reliable backup power generation to the community after grid connection.

Remotes will continue to explore and leverage new technologies and innovative approaches where possible over the forecast period.

<u>Consideration of Traditional Planning Needs</u>

As previously explained in Section 5.3, traditional planning needs, including load growth, asset condition and reliability are key inputs considered as part of Remotes' planning and AM processes. Load growth is a direct input into Remotes' planning for system access and system service type projects. Asset condition and reliability data are key inputs considered by Remotes when identifying, selecting and prioritizing system renewal expenditures for both distribution and generation assets.

<u>Overall Capital Expenditures</u>

Over the forecast period Remotes' capital expenditures are designed to continue to meet Remotes' corporate goals including safe, reliable and affordable power. Remotes will continue to follow its established AM processes to determine and justify capital expenditures. Unlike other utilities, a significant portion of Remotes' capital assets are funded by others, so net capital expenditures is often a better indicator. For 2022-2024, a short-term increase is expected as Remotes prepares for grid connection with one-time spending on distribution wholesale metering, and facility costs to accommodate the additional staff, yard and shop space required to manage and support the additional services and communities being added to Remotes' customer base. After the 2022-2024 short-term increase, Remotes expects capital costs to decrease, as distribution capital spending returns to more traditional levels and generation capital spending including replacements drops off due to grid connection and reduced generator running hours. The trends over the 2018 to 2027 period, for net capital expenditures and the underlying investment categories, are shown in Figure 5.4-7.

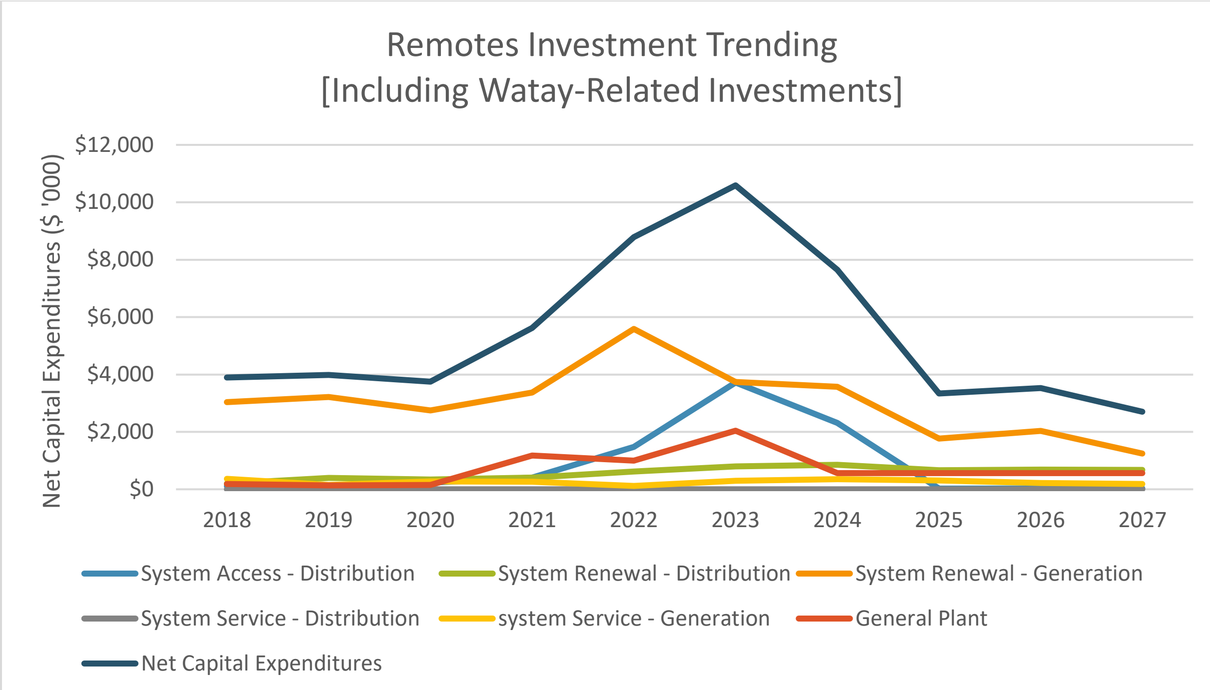


Figure 5.4-7: Historical & Forecast Investment Trends – Including Watay Investments

To demonstrate the impact of the Watay Project on Remotes' investment trending, the following graph illustrates Remotes' investment trending excluding key costs associated with the Watay Project (i.e., the wholesale metering and facility expansion/relocation costs). As can be seen in this figure, the short-term increase between 2022-2024 is significantly reduced.

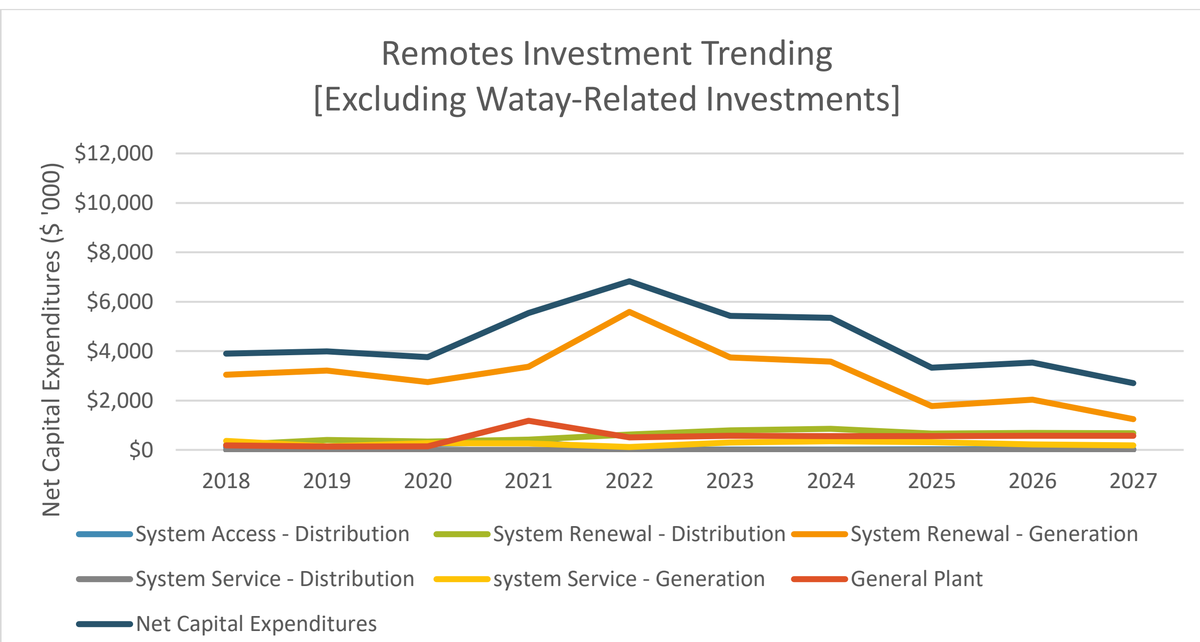


Figure 5.4-8: Historical & Forecast Investment Trends – Excluding Watay Investments

5.4.2.1 Material Investments

For this Application, the materiality threshold is $673,000. Remotes' 2023 material investments are summarized in Table 5.4-16. Detailed scope of each material investment along with key drivers and justifications are described in detail in Appendix A and briefly summarized below.

Table 5.4-16: List of Material Investments for the 2023 Test Year

Investment Category	Material Project / Program	Bridge	Forecast				
		2022	2023	2024	2025	2026	2027
		$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
System Access – Distribution	Watay Grid Connection 4-Pole Cluster	1,394	3,644	2,263	0	0	0
	New Customer Connections and Service Upgrades	997	1,113	1,255	1,322	1,346	1,371
System Renewal – Generation	Armstrong A & B Unit Generator Replacements	0	1,270	1,154	0	0	0
	Big Trout Lake (KI) A Unit Generator Replacement	4,287	868	0	0	0	0
	Lansdowne House (Neskantaga) C Unit Generator Replacement	0	296	1,175	0	0	0
	Lansdowne House (Neskantaga) Bulk Tank Replacement	0	394	391	0	0	0
System Service – Generation	Lansdowne House (Neskantaga) DGS Upgrade	0	501	2,105	0	0	0
	Gull Bay (KZA) DGS Upgrade	1,300	2,700	0	0	0	0
General Plant	Beaverhall Facility Expansion/Relocation	490	1,476	0	0	0	0

<u>Watay Grid Connection 4-Pole Cluster</u>

The Watay Grid Connection 4-Pole Cluster project involves the design and construction for 4-pole distribution clusters in each of the 16 communities being connected to the Watay Project. This investment is required to allow the connection of the communities to the provincial electricity grid.

The investment is expected to serve as the demarcation point for the Remotes and Watay grid connection in each of the connected communities and will also serve as the IESO metering point as required under the Transmission System Code.

<u>New Customer Connections and Service Upgrades</u>

The New Customer Connections and Service Upgrades program involves the connection of new load customers to the Remotes' distribution system and the upgrade of service for existing load customers as required. The main driver for this investment is customer-initiated requests. New connections and service upgrades are customer-funded and are entirely recoverable.

The investment is expected to meet Remotes' requirements to connect new services and to upgrade existing services in compliance with distribution regulatory and licence obligations.

<u>Armstrong A & B Unit Generator Replacements</u>

The Armstrong A & B Unit Generator Replacement project involves the replacement of the Armstrong A and B generation units which supply electricity to over 365 customers across three communities. The communities served by Armstrong A and B will not be grid-connected by the Watay Project and will therefore continue to rely on diesel-generated electricity. The two generator units have reached the 60,000-hour engine operating threshold and are also in poor condition. The investment also replaces the master control system for the generators at Armstrong DGS. The existing master control system is not compatible with the engine control systems being installed with the two replacement generators and is also obsolete and no longer supported by the manufacturer.

The investment is expected to ensure the continued delivery of safe and reliable prime-power generation in Armstrong, with Armstrong DGS as the only source of electricity for the communities for years to come.

Big Trout Lake (KI) A Unit Generator Replacement

The Big Trout Lake (KI) A Unit Generator Replacement project involves the replacement of Big Trout Lake DGS with a modular DGS. The Big Trout Lake DGS relies on three generation units to supply electricity to over 411 customers in the community of Big Trout Lake. The Big Trout Lake A generation unit has reached the 60,000-hour engine operating threshold and is also in poor condition, and due to regulatory, safety and environmental issues identified throughout the existing DGS, the only suitable alternative is a full replacement of Big Trout Lake DGS. The proposed modular DGS will house three new generation units and the existing Big Trout Lake B and C generation units will be decommissioned and either placed into storage to be used as spare units or be auctioned off. The community of Big Trout Lake is expected to become grid-connected by the Watay Transmission project in June 2023, which will reduce the community's reliance on diesel-generated electricity and at which time the new modular DGS will be used for providing backup power.

The investment is expected to ensure that the new modular DGS meets all of the standards and regulations and will ensure the continued delivery of safe and reliable backup-power generation in Big Trout Lake.

Lansdowne House (Neskantaga) C Unit Generator Replacement

The Lansdowne House (Neskantaga) C Unit Generator Replacement project involves the planned replacement of the Lansdowne House Unit C generator. The C Unit generator has been assessed in fair condition and is forecast to exceed the 60,000 engine-hour threshold limit by 2024. As the community of Lansdowne will not be grid connected to the Watay Project, the replacement of the generation unit is critical to reliability of supply for existing customers.

By proactively addressing the condition of the generator, this investment is expected to mitigate failure risks to generation supply; and to support effective operation of the Lansdowne House diesel generating station, which will be the only source of electricity for the community in the years to come.

Lansdowne House (Neskantaga) Bulk Tank Replacement

The Lansdowne House (Neskantaga) Bulk Tank Replacement project involves the planned replacement of two 50,000L bulk fuel tanks that are not compliant with current fuel regulations and are also assessed to be near end-of-life. Non-compliance with regulations will result in the need for additional fly-in fuel, to meet community generation demand.

By proactively addressing the non-compliance and condition issues, this investment is expected to mitigate reliability risks to fuel supply and support effective operation of the Lansdown House DGS.

Lansdowne House (Neskantaga) DGS Upgrade

DGS capacity upgrade investments address system capacity issues that arise from community load growth. The Lansdowne House (Neskantaga) DGS Upgrade project involves the upgrade of the Lansdowne House A generation unit with a new 1,000 kW unit which, along with two other units, supply electricity to over 112 customers in the community of Lansdowne. The peak station load at Lansdowne House reached 703 kW in 2020, nearing its connection restriction limit of 744 kW, or 85% of the station prime rating. Since the community of Lansdowne will not be grid connected to the Watay Project, a capacity upgrade of the Lansdowne House Unit A generator has become critical to reliability of supply for existing customers as well as forecast community load growth. The existing generation unit A will be decommissioned, and either be reused, placed into storage to be used as a spare unit or be auctioned off. The investment also replaces the step-up transformer. The Lansdowne House DGS upgrade costs are fully recoverable through a long-standing agreement with ISC.

The investment is expected to increase the Lansdowne House DGS prime rating from 875 kW to 1,200 kW and raise the connection limit to 1,020 kW. This investment addresses the capacity issue through the DGS upgrade, resulting in the continued ability of the system to meet forecast customer demand. By implementing this project, the customers in Lansdowne will be able to make new connections to the distribution system in order to add more housing and supply new critical infrastructure projects within the community.

Gull Bay (KZA) DGS Upgrade

The Gull Bay (KZA) DGS Upgrade project involves the upgrade of the Gull Bay B generation unit with a new 725 kW unit which, along with two other units, supply electricity to over 123 customers in the growing community of Gull Bay. The community served by Gull Bay DGS will not be grid-connected by the Watay Project and will therefore continue to rely on diesel-generated electricity. Due to the continued growth in this community, the peak station load at Gull Bay DGS reached 340 kW in 2021 or 93% of the connection restriction limit and 85% of the station prime rating limit. The existing generation unit B will be decommissioned and either placed into storage to be used as a spare unit or be auctioned off. The investment also replaces the step-up transformer. This investment is 100% recoverable through a funding agreement with Gull Bay First Nation and ISC.

The investment is expected to increase the Gull Bay DGS prime rating from 430 kW to 650 kW and raise the connection limit to 553 kW, allowing for peak load growth in the community well into the future, and ensuring the continued delivery of safe and reliable prime-power generation in the community of Gull Bay.

Beaverhall Facility Expansion/Relocation

The Beaverhall Facility Expansion/Relocation project involves the expansion or relocation of Remotes' main offices which are currently fully utilized and at capacity, and which will no longer adequately serve the needs of its customers. Remotes will also be required to increase current staff levels by up to four people in 2023 to account for the additional work associated with the six IPA communities being added to Remotes' customer base, as well as ensuring uninterrupted routine work. The investment also increases the available yard space for equipment and materials and create a dedicated shop space.

The investment is expected to provide the necessary space required to provide a workplace where employees can work safely in all areas of the facility and will allow Remotes to increase staffing resources to ensure that its customers receive quality customer service and reliable power. Working conditions are expected to improve as overcrowding is eliminated, while the increased yard space will allow for equipment and materials to be stored properly providing a safe area to work efficiently. Additionally, the increased shop space is expected to eliminate the need for trade staff to perform work in high traffic areas.

Appendix A

Material Investment Narratives

Material Investment Narrative

Watay Grid Connection
4-Pole Cluster

INVESTMENT SUMMARY	
Main Driver:	**Third Party Infrastructure Development Requirements (Wataay Project)**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness, Public Policy Responsiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	3,644	2,263	0	0	0

Summary:

This investment involves the design and construction for 4-pole distribution clusters in each of the 16 communities being connected to the Wataay Project. This investment is required to allow the connection of the communities to the provincial electricity grid.

The investment is expected to serve as the demarcation point for the Remotes and Wataay grid connection in each of the connected communities and will also serve as the IESO metering point as required under the Transmission System Code.

A. General Information on the Project/Program

1. Overview

The Wataynikaneyap grid connection project (Watay Project) is a generational project that will revolutionize energy in Northern Ontario. The Wataay Project corresponds to the construction of a transmission line that will connect 16 remote First Nation communities in Northern Ontario to the Ontario Power Grid. Over the plan period, Remotes will see growth in its service territory and will transition to a Transmission connected distributor while continuing to offer off-grid generation and distribution services.

Remotes is requesting the approval of $7.407M for the purchase of materials, design, and construction costs for a 4-pole cluster in each of the communities being connected to the Wataay Project. The 4-pole cluster is a collection of individual pole designs required at each location. The common design elements of the 4-pole cluster, shown in Figure 1 below, includes a tension change dead-end, wholesale revenue metering, G&W Electric Viper recloser, and load break disconnect pole. SCADA (supervisory control and data acquisition) and communication components will also be included, unique to requirements of each community.

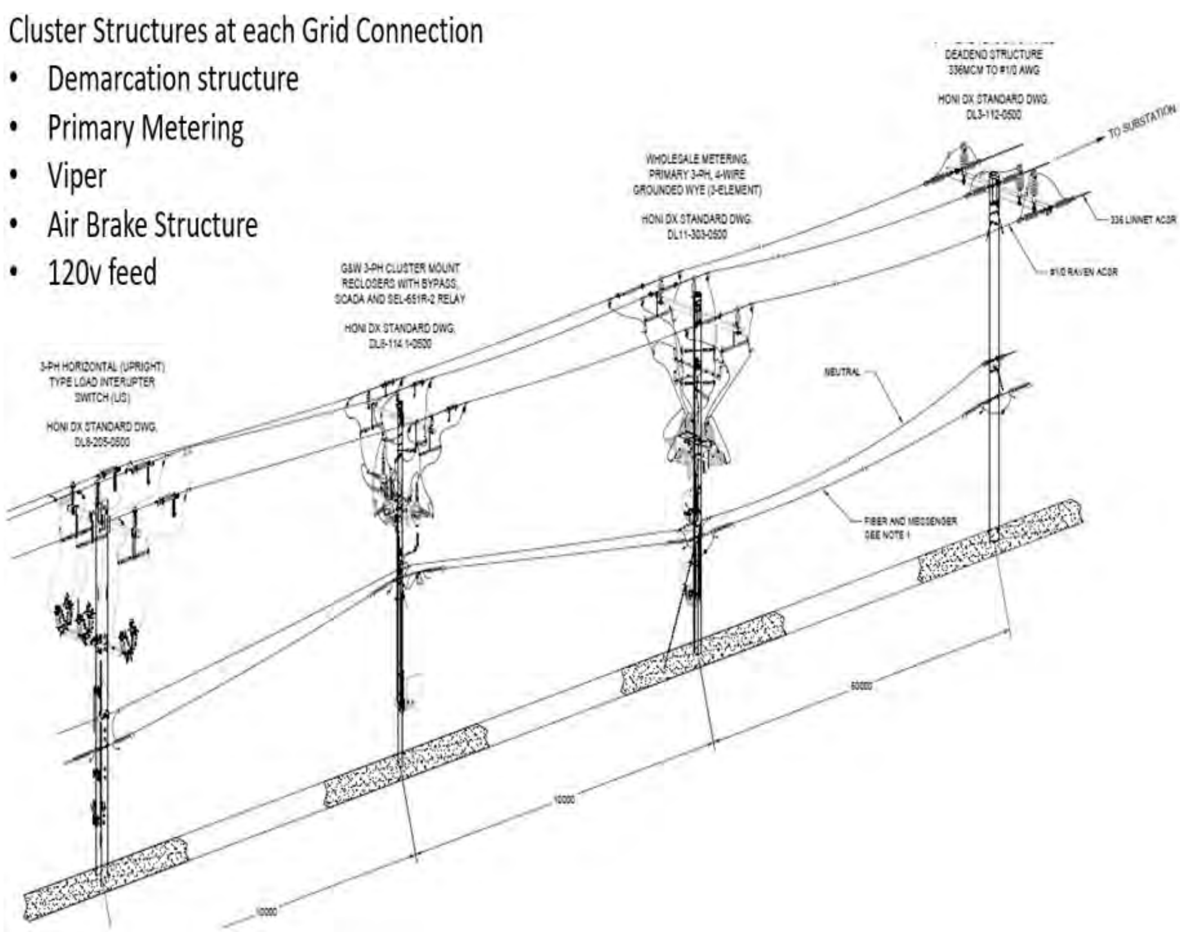


***Figure 1**: 4-Pole Cluster Design.*

The 4-pole cluster will include the demarcation point for the Remotes / Wataynikaneyap Power LP (Watay) grid connection to each community. In addition, this structure will serve as the Independent Electricity System Operator (IESO) metering point as required under the transmission code and is necessary for grid connection compliance. The initial design work for this project was completed in 2021 for $106,000.

This is a multi-year project that will be executed based on the scheduled grid connection to the communities, with most of the work being done a few months prior to grid connection. The structures will be placed into service on grid connection day. The planned community connection dates and associated project costs are summarized in Table 1.

***Table 1**: Scheduled Grid Connections and Costs*

In-Service Date[1]	Cost ($'000)	Communities Connected
2022	$1,394	Pikangikum, Weagamow, Kingfisher
2023	$3,644	Muskrat Dam, Sachigo, Bearskin, Wawakepewin, Wunnumin, Wapekeka, Big Trout, Kasabonika
2024	$2,263	Poplar Hill, Deer Lake, North Spirit, Sandy Lake, Keewaywin

[1] The in-service date shown is based on the October 2021 version of the Watay Project schedule.

This project is required to ensure community readiness and a smooth transition to regulated service and connection to the Ontario Power Grid.

2. Timing

i. *Start Date:* January 2022, with varying starting dates by community

ii. *In-Service Date*: March 2024, with varying in-service dates by community

iii. *Key factors that may affect timing:* The timing of this project is highly dependent on the execution timing of the Watay Project and the scheduled grid connections to the communities, which is a function of the readiness of the transmission line and distribution stations at each community connection point. Other factors that may affect timing include IPA readiness, regulatory approvals, construction needs, resource availability and COVID-related delays.

3. Historical and Forecast Capital Expenditures

***Table 2**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	106	1,394	3,644	2,263	0	0	0	7,407
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	106	1,394	3,644	2,263	0	0	0	7,407

The costs are non-recoverable and are paid by the distributor/customer under the current regulatory framework.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The 4-pole cluster is a collection of individual pole designs required at each location. The project costs comprise design, material, construction, contractor, and overhead costs required within each community. Mobilization and demobilization cover a significant portion of the costs. Similar individual pole designs have been used by Remotes in the past, but this is the first time that Remotes is using them in a clustered manner.

6. Investment Priority

This is a high priority investment. Without this investment, multiple remote communities will not be able to connect to the Watay Project and the provincial grid, which will hinder the completion of the project and community access to reliable electricity.

7. Alternatives Analysis

No alternatives were considered. This investment is non-discretionary. Revenue metering is critical to ensure reliable and accurate billing in accordance with regulatory requirements.

8. Innovative Nature of the Project

The 4-pole cluster is a collection of structures that all have standard designs. However, clustering the structures together in series, placed as close to each other as possible, is unique for Remotes as it is the first time that this 4-pole cluster is used. This design will ensure a safe and reliable connection to the provincial grid that is compliant with all regulated service connection requirements.

8. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 3: *Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Connection to the provincial grid will alleviate the potential for connection restrictions as the electrical capacity of the grid components will be much higher than the existing capacity of the diesel generating stations (DGS). In addition, the existing DGS within the grid-connected communities will be used as backup power only, and as a result, Remotes expects less callouts for unexpected maintenance response which will

Primary Criteria for Evaluating Investments	Investment Alignment
	result in improved operational efficiency and allow staff to be redeployed to other critical maintenance and capital project tasks.
Customer Value	This investment will connect 16 communities to the provincial grid. With this, these communities will have access to reliable electricity supply and there will be an increased ability to add new housing and other infrastructure to support community growth and development. Being connected to the grid will also reduce the level of diesel emissions within these communities.
Reliability	DGS have a limited capacity that must be increased periodically to satisfy increasing demand in communities. The capacity increase does not always occur in a timely manner and new connections might be restricted to maintain reliability for existing customers. With the Watay Project, these restrictions will be eliminated within the grid-connected communities. Additionally, Remotes will continue to provide backup generation in most grid-connected communities and maintain the 25kV distribution lines to ensure the communities have continued access to reliable electricity during any future outage events on the new Watay transmission grid.
Safety	Due to this investment, Remotes' existing DGS will no longer be running near their rated capacity and therefore will have less chance of catastrophic failures that could pose a safety or fire risk. In addition, the 4-pole structures demarcation points which will improve worker safety and provide faster emergency responses.

2. INVESTMENT NEED

The Watay Project is a major development in many communities in Remotes' service territory. Sixteen communities will be connected to the provincial grid and be able to access reliable electricity supply for community growth and development.

i. *Main Driver*: Third Party Infrastructure Development Requirements (Watay Project) – The main driver for this project is the development of the Watay Project and the associated need for infrastructure to connect the 16 communities to the provincial grid. Remotes has an obligation to Watay and the communities to facilitate these interconnections. The need for connection to the Watay Project has also been identified by community leadership as essential for their growth and development, and the 16 communities that will get access to the provincial grid are Watay Project partners as well.

ii. *Secondary Drivers*: Mandated Service Obligations - The investment is expected to serve as the demarcation point for the Remotes and Watay grid connection in each of the connected communities and will also serve as the IESO metering point as required under the Transmission System Code. Revenue metering is critical to ensure reliable and accurate billing in accordance with regulatory requirements.

iii. *Information Used to Justify the Investment*: The need for this investment was identified through ongoing consultations with Watay and the community members and leadership. A reliable connection to the provincial grid and the increased capacity will help promote growth and development in the remote communities, while also reducing the level of diesel emissions within these communities. Revenue metering is also critical to ensure reliable and accurate billing in accordance with regulatory requirements.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: Remotes is in contact with Wataay, its contractor, Indigenous community leaders and their advisors through regular meetings to ensure the purpose and goals of the project are in alignment. Remotes is also ensuring that the wholesale revenue metering will be registered with the IESO and installed per the IESO Market Rules. Remotes will also ensure that the 4-pole clusters are constructed in accordance with Remotes practices and *O. Reg 22/04* requirements.

ii. *Cost-Benefit Analysis:* The proposed project is required to connect the 16 communities to the provincial grid. No alternatives were identified.

iii. *Historical Investments & Outcomes Observed:* Remotes has successfully undertaken standard pole design and construction projects in the past that have accommodated new customer connections to their distribution system. Similar design principles are being used as part of the 4-pole cluster.

iv. *Substantially Exceeding Materiality Threshold:* The Wataay Project is a major development in many communities in Remotes' service territory. This project is required to accommodate the interconnection of 16 remote communities to the provincial grid. The justifications for this project are included within this material investment narrative.

4. Conservation and Demand Management

CDM is not applicable for this project.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis*: This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

This project uses the same order of structures placed as close to each other as possible in a series in every community that Remotes is connecting. This design will ensure a safe and reliable connection of communities to the provincial grid that is compliant with all regulated service connection requirements.

Material Investment Narrative

New Customer Connections and Service Upgrades

Investment Summary

Main Driver:	**Customer Service Requests**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness, Public Policy Responsiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Cost	0	0	0	0	0

Summary:

This investment involves the connection of new load customers to the Remotes' distribution system and the upgrade of service for existing load customers as required. New connections and service upgrades are customer-funded and are entirely recoverable. The main driver for this investment is customer-initiated requests.

The investment is expected to meet Remotes' requirements to connect new services and to upgrade existing services in compliance with distribution regulatory and licence obligations.

A. General Information on the Project/Program

1. Overview

Remotes currently serves 22 communities across Northern Ontario, among which 17 are First Nation communities. Cat Lake and six new IPA communities are anticipated to join Remotes' distribution system in 2023 and 2024. To support the growth and development of these communities, Remotes routinely accommodates new customer connections and service upgrades.

Capital projects included under this program are customer-initiated requests for connection to Remotes' distribution system and/or expansion of distribution assets to accommodate such requests. New customer connections vary from year to year and may include provision/expansion of distribution lines, transformers, switches, fuses, meters, and electrical termination facilities. New connections and service upgrades are planned using standardized designs that meet the requirements of *O. Reg. 22/04*, made under the *Electricity Act, 1998*. Remotes manages the engineering and design costs of these projects, while providing consistent design quality throughout its service territory. Investments in this program are initiated by customers and project costs are 100% recoverable and any cost savings are directly passed on to the customers. The forecast costs under this program are informed by historical trends, considerations of growth and development and the connection of new communities.

New customer connections and service upgrades allow customers to connect to Remotes' distribution system in their community and have vital access to electricity. Connecting new customers to the system also fosters growth and development within the community.

2. Timing

i. *Start Date:* January 2023, with customer connects varying on start date

ii. *In-Service Date:* December 2027, with customer connects varying on in-service date

iii. *Key factors that may affect timing*: Year-over-year fluctuations in the volume of work performed under this program vary based on the number of customer requests received each year. The timing of work depends on when the customer request is made. Most connections are completed in the same year as the customer request, however some carry-over until the following year.

3. Historical and Forecast Capital Expenditures

***Table 1**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($'000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	775	1,248	783	1,340	997	1,113	1,255	1,322	1,346	1,371
Contributions	(741)	(1,212)	(770)	(1,297)	(997)	(1,113)	(1,255)	(1,322)	(1,346)	(1,371)
Removals	(16)	(27)	(10)	(9)	0	0	0	0	0	0
Capital (Net)	18	9	3	34	0	0	0	0	0	0

New connections and service upgrades are customer-funded and 100% recoverable. Remotes manages the engineering and design costs of these projects.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The number of forecast connections and service upgrades required fluctuates each year depending on the number of requests made by customers, and the scopes of work vary based on the size, nature, and volume of activities required to accommodate the requests. Expenditures under this program are forecast based on historical trends, considerations of growth and development within the communities, and the addition of Cat Lake and the six new IPA communities in 2023 and 2024. The number of customer connections is also influenced by federal Indigenous housing programs and initiatives.

6. Investment Priority

This is a non-discretionary program driven by customer service requests and the costs are fully recoverable. When customer connection and service upgrade requests are initiated, they will take priority over other system undertakings and plans.

7. Alternatives Analysis

No alternatives are considered. This work is a regulatory requirement. Not proceeding with customer-initiated requests would result in non-compliance with Remotes' obligations under its distribution license requirements and the Distribution System Code.

8. Innovative Nature of the Project

There is nothing inherently innovative to Remotes about this program.

9. Leave to Construct Approval

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 2**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Remotes manages the engineering and design costs of these projects through standardized designs, while providing consistent and efficient design quality throughout its service territory. When the scope of the project includes the replacement of distribution transformer(s), newly procured transformer units will meet the latest standards in energy efficiency. Remotes also attempts to coordinate new

Primary Criteria for Evaluating Investments	Investment Alignment
	connections and/or service upgrades where possible to optimize efficiency and cost effectiveness by combining work into a single trip.
Customer Value	The main benefit to customers is connection to the electrical system and having access to reliable electricity. In addition, connecting new customers to the system encourages economic growth and development in the respective communities. Enabling customer requests for connection within established timeframes will also help ensure customer satisfaction.
Reliability	Connecting new customers has impacts on system capacity. To circumvent this, Remotes accounts for this impact during its planning phase and works closely with the communities it serves to ensure adequate system capacity is in place to serve their immediate and future needs.
Safety	All new construction conforms to the latest standards for health and safety protections and performance. New smart meters installed under this program as part of the customer connection or service upgrade also meet the latest cyber-security standards.

2. Investment Need

This program is driven by customer service requests. The changing population and more intensive use of electricity in remote communities has increased the overall number of new connections for Remotes in recent years and is expected to continue growing. This plan also anticipates the addition of Cat Lake and six new communities currently serviced by an IPA in 2023 and 2024. It is imperative for Remotes to accommodate these requests in order to maintain customer satisfaction and facilitate the growth and development of remote communities in northern Ontario by providing access to reliable electricity supply.

i. *Main Driver*: Customer Service Requests - Projects within the program are driven by customer service requests. This work is non-discretionary, and the scopes and timelines are based on requirements from the customers requesting the services.

ii. *Secondary Drivers*: There are no secondary drivers associated with this program.

iii. *Information Used to Justify the Investment*: The projects undertaken in the program are based on customer requests. The number of customer connections and service upgrades are forecast based on historical trends, considerations of growth and development within the communities, and the addition of Cat Lake and the six new communities currently serviced by an IPA in 2023 and 2024. Remotes also consults with customers and communities on a regular basis to remain informed on their connection needs and expectations for growth and development within the communities.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: New connections and service upgrades are planned using standardized designs that meet the requirements of *O. Reg. 22/04*. In doing so, Remotes manages the engineering and design costs of these projects, while providing consistent design quality throughout its service territory. Customers also follow a standardized connection process by calling Remotes customer service department. At a high level, the process includes requesting service, designing the layout, and setting up an account. Once the Electrical Safety Authority (ESA) has inspected the premises, connection and construction work takes place after payment is received.

ii. *Cost-Benefit Analysis:* Alternative methods of new customer connections and service upgrades come with ownership and maintenance issues, which will hinder Remotes' ability to manage costs and maintain electrical reliability for customers. Investment in projects under this program follow standardized designs to allow access to affordable and reliable power supply to both new and existing customers.

iii. *Historical Investments & Outcomes Observed:* Remotes routinely provides new connections and service upgrades to remote communities. These investments have allowed continued growth and development within the communities which benefited residents. They also allowed Remotes to ensure dependable generation and reliability for existing customers.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this program are included within this material investment narrative.

4. Conservation and Demand Management

CDM is not applicable for new customer connections and service upgrades.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis*: This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

There is nothing inherently innovative to Remotes about this program.

Material Investment Narrative

Armstrong A & B Unit Generator Replacements

INVESTMENT SUMMARY

Main Driver:	**Failure Risk**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	1,270	1,154	0	0	0

Summary:

This investment involves the replacement of the Armstrong A and B generation units which supply electricity to over 365 customers across three communities. The communities served by Armstrong A and B will not be grid-connected by the Wataay Transmission project and will therefore continue to rely on diesel-generated electricity. The two generator units have reached the 60,000-hour engine operating threshold and are also in poor condition. The investment also replaces the master control system for the generators at Armstrong DGS. The existing master control system is not compatible with the engine control systems being installed with the two replacement generators and is also obsolete and no longer supported by the manufacturer.

The investment is expected to ensure the continued delivery of safe and reliable prime-power generation in Armstrong, with Armstrong DGS as the only source of electricity for the communities for years to come.

A. General Information on the Project/Program

1. Overview

The Armstrong diesel generation station (DGS) was originally built in the late 1990's and currently consists of 3 diesel generators: Armstrong A, B and C. The plant currently supplies electricity to over 365 customers in the communities of Armstrong, Collins and Whitesand First Nation (Collins and Whitesand are served via the Armstrong distribution system). These communities will not be grid-connected when the Watay Transmission Project comes online, and as a result, these units are critical and are required to supply electricity to the communities for years to come. The engine size, speed, vintage, condition and current and forecast engine hours are summarized in the Table 1.

Table 1: *Engine Condition of Generators in Armstrong Diesel Generation Station*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition [2]	Engine Hours[3]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Armstrong A	725	1,800	2018	Poor	77,766	80,904	84,045	87,185	90,325	93,466
Armstrong B	725	1,800	2011	Poor	62,262	65,609	68,957	72,302	75,561	78,998
Armstrong C	1,100	1,800	1999	Poor	51,436	53,486	56,035	58,583	61,131	63,679

[1] In-service year normally corresponds to the year the unit was installed. In the case of the Armstrong units, this corresponds to the year the engine block was changed. For the Armstrong A and B units, although the block was changed in 2018 and 2011 respectively, the other components on the units were put in service in 1999.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The engine condition is current as of February 2022.
[3] Engine-hours shown are current as of February 8, 2022.

The manufacturer's published recommendations for medium-speed generators (1,800 rpm) include complete overhauls after 20,000 hours, and Remotes has a policy that generators of this type shall be replaced once they reach the threshold for a third overhaul, generally at about 60,000 engine-hours. In addition, the units are inspected and maintained every 2,500 hours to determine the condition. Based on this, Remotes is proposing to implement two generator replacements over the forecast period:

- **Armstrong A:** The Armstrong A unit is in poor condition and is beyond the 60,000 engine-hour threshold that triggers replacement. An identical like-for-like replacement is not possible due to the late-1990's vintage of the unit, however the replacement unit will have a similar capacity and speed. The engine replacement will also require a new radiator, aftercooler, and exhaust system. Pictures of the unit are included in Attachment 1.

- **Armstrong B:** The Armstrong B unit is in poor condition and is beyond the 60,000 operating hour threshold that triggers replacement. An identical like-for-like replacement is not possible due to the late-1990's vintage of the unit, however the replacement unit will have a similar capacity and speed. The engine replacement will also require a new radiator, aftercooler, and exhaust system.

Although the Armstrong C unit is approaching end of life, Remotes is considering running the unit beyond the normal replacement timelines knowing that the other two newer units will operate the majority of hours and provide an added level of reliability. Ongoing consideration is being made to replace the C unit with an alternate sized unit, but Remotes is hoping to hold off until the Armstrong area load/economy balances and further integration and optimization into the potential biomass project can be explored.

In addition to the planned unit A and B replacements, the existing control system in the Armstrong DGS is obsolete, is no longer supported by the manufacturer and is not compatible with the newer engine control systems being installed with the replacement units. As a result, a new master control will be installed at the DGS and the Armstrong C unit will be upgraded to the newer controls as part of this project.

Remotes plans to invest $2.424M in 2023 and 2024 to complete the necessary work at the Armstrong DGS. Remotes decided to complete both engine replacements and control system upgrades simultaneously to enable time and cost efficiencies. This project is necessary to ensure continued delivery of safe and reliable electricity to the communities. A breakdown of the costs is as follows.

Table 2: *Cost Breakdown of the Project*

Cost Breakdown	Cost ($ '000)
Generators and Controls	1,451
Radiators, Exhausts, Piping, Miscellaneous Materials	300
Installation	500
Design	135
Fleet/TWE	38
TOTAL	**2,424**

2. TIMING

i. Start Date: March 2023

ii. In-Service Date: November 2024

iii. Key factors that may affect timing: A delay in receiving the necessary materials and equipment, especially long lead items, could delay the project by up to a year. The availability of resources needed to complete the project can also impact timing.

3. Historical and Forecast Capital Expenditures

***Table 3:** Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	0	1,270	1,154	0	0	0	2,424
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	1,270	1,154	0	0	0	2,424

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Typical generator replacements will require a new radiator, a complete aftercooler piping circuit, an upgraded exhaust system, and electrical control and power upgrades. However, this project is more involved than a typical generator replacement. The need for upgraded controls on the C unit and an upgraded master control is beyond the scope of a normal replacement project. Therefore, this project will be more costly.

This project is expected to cost $2.424M. In order to compare the cost to other similar generator replacement projects, cost per kW can be considered. The new 1,800 rpm units will each have a capacity of 725 kW (1,450 kW in aggregate), rendering the cost per kW at $1,672.

A similar generator replacement was completed at Deer Lake in 2016, where a new 1,200 rpm generator unit with capacity of 1,500 kW was installed at the total cost of $1.75M, and per-kW cost of $1,166. The observed cost differences can mostly be attributed to the difference in generator speed and the additional cost associated with the upgrade of the station controls and C unit controls as part of the Armstrong project.

6. Investment Priority

This is a high priority project as it is integral in maintaining reliable prime-power generation in Armstrong which is not being grid-connected. This DGS will be the only source of electricity for the communities for years to come.

7. Alternatives Analysis

Remotes has considered the following options:

- Option 1: Do Nothing – This is not a viable alternative as it would jeopardize the electricity supply to the communities.
- Option 2 – Rebuild Engine – Both the A and B units have already been overhauled twice, and the A unit is operating beyond the recommended replacement threshold. Additionally,

fuel pumps are no longer available to rebuild these units so they cannot be rebuilt. As a result, this is not a viable option.

- Option 3 – Replace Engines & Upgrade Controls (Selected Option) – Remotes' extensive experience with generators provides knowledge that after a third overhaul, engines are inherently less reliable and no longer perform satisfactorily. They have more wear on the block and crankshaft (parts that are not replaced during an overhaul) that will cause oil leaks, coolant leaks, and other issues that will require increased maintenance effort and costs. As these generators are critical sources of electricity for these remote communities, it is imperative to ensure these generators continue to function safely and reliability, and therefore Remotes has identified an engine replacement as the only viable option. To support the new units, a new master control will also be installed at the DGS and the Armstrong C unit will be upgraded to the newer controls as part of this project. Replacing the generators will likely have a small incremental benefit on both fuel usage and emissions as technology has continued to improve.

- Option 4 – Replace Engines & Keep Existing Controls – Since the existing control system in the Armstrong DGS is obsolete, is no longer supported by the manufacturer and is not compatible with the newer engine control systems being installed with the replacement units, this is not a viable option.

8. Innovative Nature of the Project

Engine replacements are routine in nature and not innovative for Remotes. However, the control upgrade is not customary and will require extra effort. The new engines will also be compliant with the latest standards.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 4: *Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Newer units offer improved efficiency relative to the vintage units they replace. The new units will reduce maintenance costs in the near term. This in turn allows Remotes to direct staff to other critical maintenance and capital projects.
Customer Value	Installation of a newer, more reliable unit allows Remotes to continue providing a reliable source of electricity supply to the community. There is also added benefit from the reduced maintenance costs.
Reliability	Reliability of the new unit will be better relative to the existing unit that has been rebuilt multiple times. Old engines are also more prone to catastrophic failures which, besides being a

Primary Criteria for Evaluating Investments	Investment Alignment
	safety and fire risk, would affect reliability for months until a permanent replacement unit could be installed.
Safety	New units are inherently safer than old, nearly worn-out units. There are less chances for failures and leaks which could cause safety and fire issues. The new control system will also comply with the latest cyber-security standards.

2. Investment Need

i. *Main Driver*: Failure Risk – The Armstrong A and B units are on their second engine rebuild and have surpassed the 60,000 operating hour threshold and are therefore more prone to failure. A failure of either of these units would significantly impact Remotes' customers who rely on these units as their only source of electricity.

ii. *Secondary Drivers:* It is Remotes' policy, based on manufacturer's information and past experience, to replace generators when the engine requires a third overhaul. This is the case with this unit, as it has already had two engine rebuilds. New engines are also more fuel efficient and produce less air pollutants.

iii. *Information Used to Justify the Investment*: For the last 10 years, Remotes' generator policy has been used to help guide unit replacements. The policy is based on extensive maintenance and operating experience, consultation with other off-grid utilities, and manufacturer's recommendations. This policy is also a fundamental element of Remotes' AM process for diesel generators. Additional information on manufacturer recommendations and Remotes generator policy is included below, and further information on Remotes' generation AM process can be found in Section 5.3 of the DSP.

Manufacturer's Recommended Overhaul Interval

Figure 1 highlights a representative maintenance overhaul schedule from Caterpillar. This chart recommends a major overhaul at 27,000 hours but that is at a 51% load factor. Prime power generators typically run in the 60-70% load factor range. Toromont (Caterpillar's Ontario representative) recommends 20,000-hour intervals for major overhauls and all Canadian utilities use the 20,000-hour major overhaul interval for their 1,800rpm generators.

Service Hours and Fuel Consumption for the 3512C Engine		
Interval	**Fuel Consumption[1]**	**Fuel Consumption[2]**
250 Service Hours	32980 L (8712 US gal)	41534 L (10972 US gal)
500 Service Hours	65960 L (17425 US gal)	83067 L (21944 US gal)
1000 Service Hours	131921 L (34850 US gal)	166138 L (43889 US gal)
2000 Service Hours	263842 L (69700 US gal)	332275 L (87778 US gal)
3000 Service Hours	395765 L (104550 US gal)	498414 L (131667 US gal)
6000 Service Hours	791526 L (209099 US gal)	996824 L (263333 US gal)
Top End Overhaul	1187291 L (313649 US gal)	1495238 L (395000 US gal)
	9000 Service Hours	
Second Top End Overhaul	2374581 L (627298 US gal)	2990475 L (790000 US gal)
	18000 Service Hours	
Major Overhaul	34000 Service Hours	27000 Service Hours
	4485713 L (1185000 US gal)	

[1] Based on 39 percent load factor.
[2] Based on 51 percent load factor.

Figure 1: *Manufacturer's Maintenance Overhaul Schedule*

Remotes' Generator Replacement Policy

Although overhaul interval recommendations are provided, generator manufacturers do not publish recommended replacement intervals. However, in 2010, Remotes implemented a policy to replace 1800rpm generators when they reached their third overhaul interval (60,000 hours). The policy is based on Remotes' extensive experience with prime power generators. Remotes found that parts which are not replaced during an overhaul (engine block, crankshaft, camshafts) showed significant wear by 60,000 hours. When generators were run beyond 60,000 hours, this wear had proven to increase breakdowns and thereby affected customer reliability. For reference, 60,000 hours is equivalent to approximately two-million miles for a transport truck engine, which is well beyond their typical lifespan.

As the current Armstrong A & B unit engines have been rebuilt twice already and have over 60,000 operating hours, they are at the point of failure and in need of rebuilding the generators should be replaced as per Remotes' policy.

3. INVESTMENT JUSTIFICATION

i. *Demonstrating Accepted Utility Practice*: This project is required to maintain the reliability of the electrical supply to the communities. Justification for this project is identical to many generator replacement projects completed by Remotes over the past 10 years, and Remotes' plan is based on similar investment and is considered good utility practice. All new installations will also comply with O. Reg. 22/04.

ii. *Cost-Benefit Analysis:* Alternatives will not ensure reliability of the electrical supply and thereby could affect the wellbeing of the communities. Generator replacement is the only alternative that has the benefit of ensuring dependable electrical supply in Armstrong, Collins and Whitesand.

iii. *Historical Investments & Outcomes Observed:* Generator replacements have shown to improve reliability and decrease maintenance costs compared to overhauling engines a third time. Historical generator replacement costs are listed in part 5 of Section A of this document.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. CONSERVATION AND DEMAND MANAGEMENT

Community demand reduction from CDM would not mitigate the lower reliability, higher maintenance costs and safety risks associated with running a high-hour engine. As a result, no viable CDM alternative has been identified for this project.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. INNOVATION

Similar generator replacements have been completed by Remotes many times, so this is not an innovative project.

ATTACHMENT 1: ARMSTRONG UNIT PICTURES

Figure 2 shows the Armstrong A unit. The Armstrong B unit is identical.

Figure 2: *Armstrong A Unit*

Figure 3 below shows the right side of the Armstrong A unit with the exhaust manifold removed during maintenance.

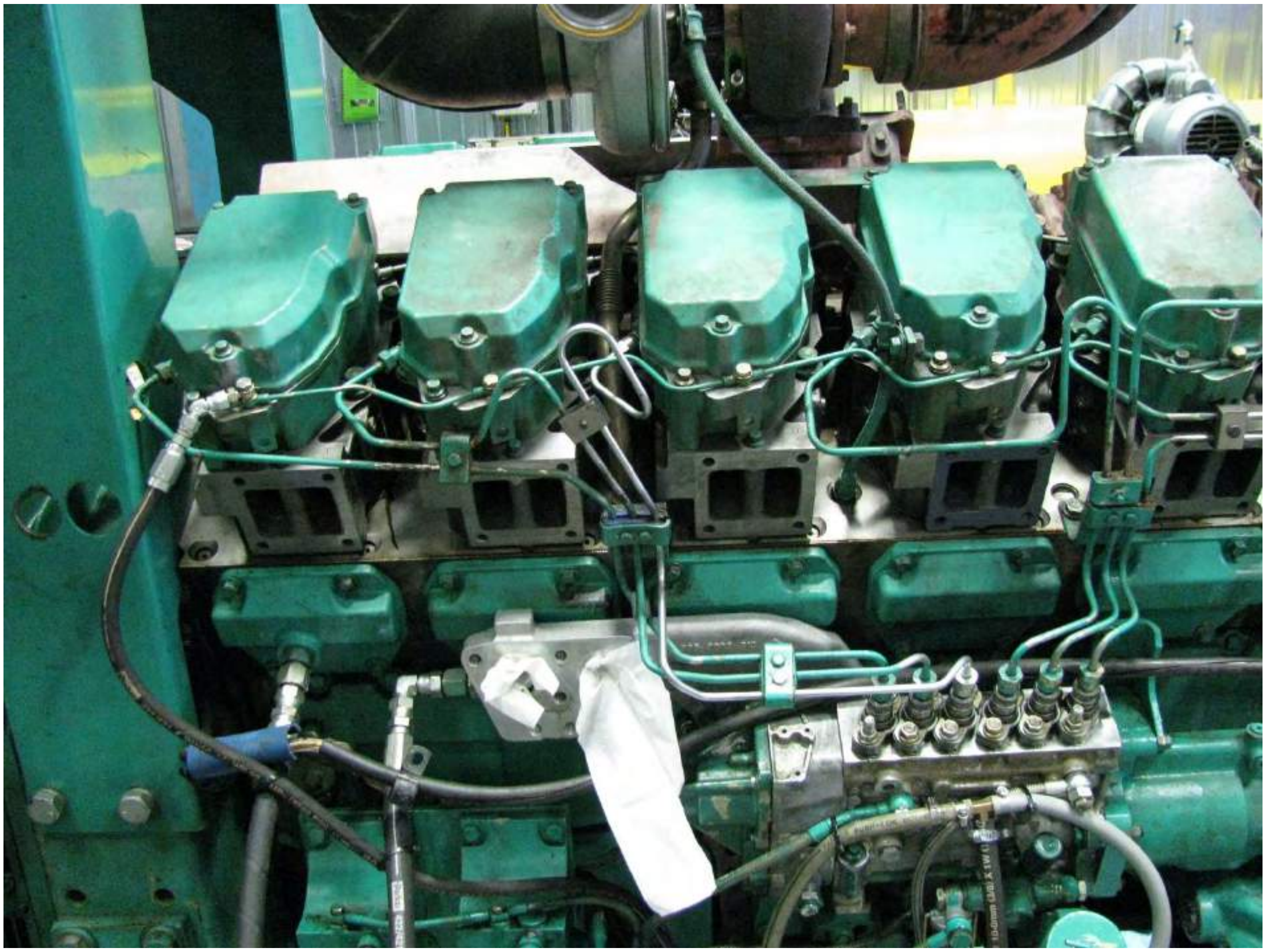


Figure 3: *Right Side of Armstrong A Unit.*

Material Investment Narrative

Big Trout Lake (KI) A Unit Generator Replacement

INVESTMENT SUMMARY	
Main Driver:	**Failure Risk**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	868	0	0	0	0

Summary:

This investment involves the replacement of Big Trout Lake Diesel Generation Station (DGS) with a modular DGS. The Big Trout Lake DGS relies on three generation units to supply electricity to over 411 customers in the community of Big Trout Lake. The Big Trout Lake A generation unit has reached the 60,000-hour engine operating threshold and is also in poor condition, and due to regulatory, safety and environmental issues identified throughout the existing DGS, the only suitable alternative is a full replacement of Big Trout Lake DGS. The proposed modular DGS will house three new generation units and the existing Big Trout Lake B and C generation units will be decommissioned and either placed into storage to be used as spare units or be auctioned off. The community of Big Trout Lake is expected to become grid-connected by the Watay Project in June 2023, which will reduce the community's reliance on diesel-generated electricity and at which time the new modular DGS will be used for providing backup power.

The investment is expected to ensure that the new modular DGS meets all of the standards and regulations and will ensure the continued delivery of safe and reliable backup-power generation in Big Trout Lake.

A. General Information on the Project/Program

1. Overview

The Big Trout Lake (KI) diesel generation station (DGS) was originally built in the 1980's and consists of 3 diesel generators: Big Trout Lake A, B and C. The plant currently supplies electricity to 411 customers in the community of Big Trout Lake. This community is expected to be grid-interconnected in June 2023, at which point the operating regime of the diesel units will change to providing backup power rather than baseload power. Through consultations with federal and provincial governments, the local communities and their project partners, Remotes has made a commitment to provide reliable back-up power in communities post-grid connection. The engine size, speed, vintage, condition and current and forecast engine hours for the Big Trout Lake units are summarized in Table 1.

***Table 1:** Engine Condition of Generators in Big Trout Lake DGS*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition[2]	Engine Hours[1]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Big Trout Lake A	600	1,800	1996	Poor	62,364	63,857	100	200	300	400
Big Trout Lake B	1,000	1,800	2019	Very Good	17,178	23,562	100	200	300	400
Big Trout Lake C	1,000	1,200	2005	Good	61,510	62,961	100	200	300	400

[1] In-service year corresponds to the year the unit was installed.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The last condition assessment was carried out in November 2021.
[3] Engine-hours shown are current as of February 8, 2022.

The manufacturer's published recommendations for medium-speed generators (1,800 rpm) include complete overhauls after 20,000 hours, and Remotes has a policy that generators of this type shall be replaced once they reach the threshold for a third overhaul, generally at about 60,000 engine-hours. In addition, the units are inspected and maintained every 2,500 hours to determine the condition. The Big Trout Lake A unit has surpassed 60,000 operating hours and is rated to be in poor condition. An engine replacement was scheduled for this generator but unfortunately a like-for-like replacement generator was not available due to the vintage of the unit, and the existing engine room is not suitable for a modern replacement generator.

Remotes considered several options, but due to a number of regulatory, safety and environmental issues identified throughout the existing station (see Attachments 1, 2 and 3 for details), the only suitable alternative is to replace the DGS with a modular generating station built elsewhere and assembled at site (see Attachment 4 for an overview). This new modular generating station will house three new generator units with similar capacities and speeds to the existing units. Unit A will be retired because of its condition and high operating hours, but since Units B and C[1] have

[1] Note: Unit C is a low speed (1,200 rpm) generator. The manufacturer's published recommendations for low-speed generators include complete overhauls after 32,000 to 40,000 hours, and as per Remotes generator policy, the required replacement at the point of needing a third overhaul would be closer to the 96,000 – 120,000 hour mark. As a result, the Big Trout Lake C unit has only had a single rebuild to date and has a lot of operating hours remaining before requiring replacement.

relatively low operating hours, these units have the potential to be reused, kept as spares or be auctioned off. Remotes will assess the potential uses of these units further once they are taken out of service.

Remotes plans to invest $5.155M to complete the replacement of the DGS with a modular generating station. The new modular generating station will meet all the latest standards and regulations and will ensure safe and reliable supply of backup power to the community for years to come.

2. Timing

i. *Start Date:* April 2022

ii. *In-Service Date:* September 2023

iii. *Key factors that may affect timing:* Remotes has to time the work such that the winter road is available to transport the equipment and materials to site. A delay in receiving the necessary materials and equipment could delay the project by up to a year when the road is available again. The availability of materials and resources needed to complete the project can also impact timing.

3. Historical and Forecast Capital Expenditures

Table 2: *Historical and Forecast Expenditures ($' 000)*

	Historical Costs ($ '000)				Bridge Year[1]	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	4,287	868	0	0	0	0	5,155
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	4,287	868	0	0	0	0	5,155

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The chosen modular station alternative is novel for Remotes so there is no direct historical comparison available. Completed engine replacement projects are not a useful direct comparison for this project since a standard engine replacement project was not possible at Big Trout Lake and would have left the DGS with unaddressed regulatory, safety and environmental issues throughout the plant. All options considered for replacement required effort well beyond the scope of a typical engine replacement.

Remotes has also undertaken full station replacements historically, however the cost associated with a full DGS build is significantly more than the cost associated with building a modular station. For example, the last full station replacement was at Webequie in 2010 and cost $12M. The cost of a new station today built in a traditional style is estimated to be close to $20M.

6. Investment Priority

Big Trout Lake is scheduled for grid connection in 2023. Although this may appear to reduce the priority of this project, Remotes has made a commitment to provide backup power to the community after grid connection and this project is the most integral part of that commitment. The existing station is not suitable for backup power as a result of safety and environmental issues. This project is a priority to ensure reliable backup power can be provided to Big Trout Lake for years to come.

7. Alternatives Analysis

The following options have been considered in determining the proposed solution:

- Option 1: Do nothing – This is not a viable alternative as it would jeopardize the electricity supply to the community.
- Option 2: Like-for-Like Replacement – Like-for-like engine replacement and block replacement for Unit A were alternatives originally considered but found to be not possible due to the vintage of the unit. As a result, this option was discarded.
- Option 3: Rebuild Unit A Engine Room – The existing A unit room does not have a floor that provides spill containment (metal plates on wood joists) and is smaller than a typical engine room that houses a modern 600kW diesel generator. One alternative considered was to remove everything from the room and pour a concrete floor to provide spill containment. However, that would not have solved the space issue and Remotes had done a similar project in Fort Severn and found that the effort was similar to a building addition. As a result, this option was discarded.
- Option 4: Building Addition – An addition to the building was considered, the scope of which would be similar to the recent upgrade project in Marten Falls (approximately $7M). This alternative would not solve switchgear safety issues and fuel system compliance issues in the existing part of the station and would have still left the station being unsuitable to supply backup power. As a result, this option was discarded.
- Option 5: Building Addition & Upgrade Existing Facility – This alternative is similar to Option 4, but includes additional upgrade work to address the switchgear safety issues and fuel system compliance issues in the existing part of the station in order to make it suitable to supply backup power. This option will not be considered going forward as the cost to complete this option was estimated at approximately $9.5M.
- Option 6: Connect Temporary Trailer Unit – Another alternative considered was to connect a temporary trailer unit in parallel with the station until grid connection. However, this does not solve the switchgear safety issues and fuel system compliance issues in the existing part of the station and would have still left the station being unsuitable to supply backup power. Since temporary units are not a long-term solution, this would have also required Remotes to find a suitable way to provide backup power after grid connection. As a result, this option was discarded.

- Option 7: Replace Existing DGS with New Modular Station (Selected Option) – The final alternative was to install a complete modular station to replace the existing DGS. The modular station is expected to be built adjacent to the existing DGS, within the existing compound. This alternative had similar costs to the building addition but had the added benefit of alleviating issues with the fuel system and switchgear. This alternative was selected as it was the only option that allowed for reliable backup power generation after grid connection.

8. Innovative Nature of the Project

This project is innovative for Remotes but not for some other utilities and mines that use diesel generators for prime power. Modular stations have been proven by others to be a suitable alternative to a traditional DGS. A common concern for a modular station has been the limited space to work inside the modular units during maintenance overhauls. However, since this station will be used for backup power, it will not accumulate enough hours to require any generator overhauls in the next 10 years.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 3**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The newer units of the modular station will be more efficient than the vintage units they will replace. The new unit will also require less maintenance and repairs than the existing unit, thereby minimizing maintenance costs for the station. This in turn allows Remotes to direct staff to other critical maintenance and capital projects.
Customer Value	Installation of a newer, more reliable units allow Remotes to provide a reliable source of backup power to the community. Customers will also benefit from the reduced maintenance costs for the station which are included in rates.
Reliability	Although the existing DGS has been reliable, this is due to diligent maintenance and quick responses to trouble at the station in recent years. All equipment in the station is being operated near its capacity which does not lend itself to reliability. Reliability of the new units will be better relative to the existing units. Old engines are also more prone to catastrophic failures which, besides being a safety and fire risk, would affect reliability until a permanent replacement unit could be installed. The new modular units will provide good reliability with reduced maintenance efforts.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	The current DGS has exposed 600V within the control cabinets which presents a safety issue not seen at other Remotes stations. The switchgear is loaded to the point that extra cooling is required in the summer to avoid overheating. The fuel system is the oldest in Remotes inventory and of a construction that hasn't been allowed for decades in new construction. The modular station will satisfy all current electrical, fuel, and other codes to ensure it is safe. New units are also inherently safer and more dependable than old, nearly worn-out units. There are less chances for failures and leaks which could cause safety and fire issues.

2. Investment Need

i. *Main Driver*: Failure Risk – The Big Trout Lake A unit is an old unit on its second engine build that has surpassed the 60,000 operating hour threshold and is therefore more prone to failure. A failure of this unit prior to grid connection would significantly impact to Remotes' customers who rely on these units as their only source of electricity. Failure of this unit post-grid connection would also impact Remotes' customers as these units are required to provide backup power to the community in the event of an outage or failure on the grid. It is Remotes' policy, based on manufacturer's information and past experience, to replace generators when the engine requires a third overhaul, which is the case with this unit.

ii. *Secondary Drivers:* Regulatory, Safety & Environment – The Big Trout Lake DGS is one of only a couple of Remotes' generating stations that remain from the 1980's. Parts of it are original and no longer meet regulations, nor provide satisfactory safety for personnel and the environment. The required improvements to the station are such that it makes sense to replace the station and thereby alleviate all issues, rather than end up with a new unit and some random fixes in an old station

   a. *Regulatory:* All of Remotes' sites are audited as part of Remotes' Environmental Heath & Safety Management System (EHSMS). There are a number of outstanding audit findings for the Big Trout Lake DGS that require attention in order for the station to meet regulations and operate safely. Building a new modular station has the added benefit of eliminating all the outstanding issues. A summary of the outstanding deficiencies identified in the Big Trout Late EHSMS audit are included in Attachment 1.

   b. *Safety*: Switchgear at the existing DGS is undersized and unsafe to operate. Building a new modular station has the added benefit of eliminating this safety concern. Additional information on this safety issue is included in Attachment 2.

c. *Environmental:* The fuel system at the existing DGS is currently out of compliance. Building a new modular station has the added benefit of eliminating this concern. Additional information on this environmental issue is included in Attachment 3.

iii. *Information Used to Justify the Investment*: For the last 10 years, Remotes' generator policy has been used to help guide unit replacements. The policy is based on extensive maintenance and operating experience, consultation with other off-grid utilities, and manufacturer's recommendations. This policy is also a fundamental element of Remotes' AM process for diesel generators. Additional information on manufacturer recommendations and Remotes generator policy is included below, and further information on Remotes' generation AM process can be found in Section 5.3 of the DSP.

Manufacturer's Recommended Overhaul Interval

Figure 1 shows a representative maintenance overhaul schedule from Caterpillar. This chart recommends a major overhaul at 27,000 hours but that is at a 51% load factor. Prime power generators typically run in the 60-70% load factor range. Toromont (Caterpillar's Ontario representative) recommends 20,000-hour intervals for major overhauls and all Canadian utilities use the 20,000-hour major overhaul interval for their 1,800rpm generators.

Service Hours and Fuel Consumption for the 3512C Engine

Interval	Fuel Consumption(1)	Fuel Consumption(2)
250 Service Hours	32980 L (8712 US gal)	41534 L (10972 US gal)
500 Service Hours	65960 L (17425 US gal)	83067 L (21944 US gal)
1000 Service Hours	131921 L (34850 US gal)	166138 L (43889 US gal)
2000 Service Hours	263842 L (69700 US gal)	332275 L (87778 US gal)
3000 Service Hours	395765 L (104550 US gal)	498414 L (131667 US gal)
6000 Service Hours	791526 L (209099 US gal)	996824 L (263333 US gal)
Top End Overhaul	1187291 L (313649 US gal)	1495238 L (395000 US gal)
	9000 Service Hours	
Second Top End Overhaul	2374581 L (627298 US gal)	2990475 L (790000 US gal)
	18000 Service Hours	
Major Overhaul	34000 Service Hours	27000 Service Hours
	4485713 L (1185000 US gal)	

(1) Based on 39 percent load factor.
(2) Based on 51 percent load factor.

***Figure 1**: Manufacturer's Maintenance Overhaul Schedule.*

Remotes' Generator Replacement Policy

Although overhaul interval recommendations are provided, generator manufacturers do not publish recommended replacement intervals. However, in 2010, Remotes implemented a policy to replace 1800rpm generators when they reached their third overhaul interval (60,000 hours). The policy is based on Remotes' extensive experience with prime power generators. Remotes found that parts which are not replaced during an overhaul (engine block, crankshaft, camshafts) showed significant wear by 60,000 hours. When generators were run beyond 60,000 hours, this wear had proven to increase breakdowns and thereby affected customer reliability. For reference, 60,000 hours is equivalent to approximately two-million miles for a transport truck engine, which is well beyond their typical lifespan.

As the current Big Trout Lake A unit engine is 26 years old, has been rebuilt twice already and has over 60,000 operating hours, it is at the point of failure and in need of rebuilding, the generator should be replaced as per Remotes' policy.

Regulatory, Safety & Environment Issues

In addition, the regulatory, safety and environmental issues identified at the existing DGS were also used to justify the need to replace the DGS with a new modular generating station. Additional information on these issues is included in Attachments 1, 2 and 3 of this material investment narrative.

Remotes' Commitment to Provide Backup Power

This community is expected to be grid-interconnected in June 2023, at which point the operating regime of the diesel units will change to providing backup power rather than baseload power. Remotes has participated in several studies and consultations focused on developing a backup power plan to support the 16 First Nation communities being connected to the provincial grid through the Watay transmission project. Studies have shown that without adequate backup power supply, the majority of the grid-connected communities would experience an increase in the frequency and duration of outages than they do currently. In addition, due to the remoteness and length of the transmission line, there is an increased risk of prolonged outages due to weather or forest fire.

Through these studies and consultations with federal and provincial governments, the local communities and their project partners, Remotes has committing to undertake the necessary actions and investments in order to provide reliable back-up power in communities post-grid connection until at least 2030. The diesel backup planning studies are included in the following DSP appendices:

- Appendix D - Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities (December 2018)
- Appendix E - Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities Containerized DGS Option Annex (November 2019)

- Appendix F - Backup Power Plan for the Connecting Communities of the Wataynikaneyap Transmission Project (April 30, 2020)

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: This project is required to maintain the reliability and availability of electrical supply to the community (existing and backup). Justification for the replacement of the Big Trout Lake A unit is identical to many generator replacement projects completed by Remotes over the past 10 years, and Remotes' plan is based on similar investment and is considered good utility practice. In addition, although building a modular station is novel for Remotes, modular stations have been proven by others (e.g., utilities and mines) to be a suitable alternative to a traditional DGS. All new installations will also comply with *O. Reg. 22/04*.

ii. *Cost-Benefit Analysis:* The only other alternative with the potential to address all the identified issues associated with this DGS is Option 5: Building Addition & Upgrade Existing Facility, however this option was estimated to cost approximately $9.5M which is nearly double the cost of the proposed solution. The selected option at a cost of $5.155 was found to be the most cost-effective solution that addresses the regulatory, safety and environmental issues while also allowing Remotes to provide reliable back up to the community power post-grid connection.

iii. *Historical Investments & Outcomes Observed:* Remotes has not had an identical investment in the past. A standard engine replacement project was not possible and would have left the station with unaddressed regulatory, safety and environmental issues. This project will address all issues by replacing the complete station in a cost-effective manner. The last full station replacement was at Webequie in 2010 and cost $12M. The cost of a new station today built in a traditional style is estimated to be close to $20M. Similar projects in the past have proven to increase reliability for customers while also decreasing environmental risks and environmental air impacts and improving employee and public safety.

iv. *Substantially Exceeding Materiality Threshold:* Additional justification for this project is included in the following attachments:
   - Attachment 1: Big Trout Lake DGS - EHSMS Audit Findings
   - Attachment 2: Big Trout Lake DGS - Safety Issues
   - Attachment 3: Big Trout Lake DGS - Environmental Issues

4. Conservation and Demand Management

The A unit represents 37% of the station rating. To defer the engine replacement, CDM would have to reduce demand by that amount which seems unrealistic in a community that always has positive growth. CDM would also not address the regulatory, safety and environmental issues identified at the existing DGS.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

The innovative aspect of this project is the replacement of a complete station with a modular station built in the south and reassembled at site. This has never been done in any Ontario remote community. This project will provide experience that could encourage similar cost-effective station replacements in the future.

Attachment 1: Big Trout Lake DGS - EHSMS Audit Findings

The Big Trout Lake Diesel Generating Station (DGS) is one of only a couple of Remotes' generating stations that remain from the 1980's. Parts of it are original and no longer meet regulations, nor provide satisfactory safety for personnel and the environment. The required improvements to the station are such that it makes sense to replace the station and thereby alleviate all issues, rather than end up with a new unit and some random fixes in an old station.

Below is a list of outstanding audit findings for the Big Trout Lake DGS that require attention in order for the station to meet regulations and operate safely. ***The replacement project will eliminate all the issues listed below.***

- 7.2.1.1. Except as permitted in Clause 7.2.1.2, tanks shall conform to one or more of the following:(a) ULC Standards (refer to Standards); (b) Section VIII of the ASME Boiler and Pressure Vessel Code; (c) The Transportation of Dangerous Goods Act, c.36, and (d) CAN/CGSB 43.146.

  B139-15 6.2.1.2

  Day tanks do not have ULC labels.

- 7.2.2.1 Tanks shall not be operated at pressures exceeding 7.0 kPa (1 psi) gauge in the vapor space.

  B139-15 6.2.2.1

  Big Trout: Venting requirements are not met. Day tank vents are tied together and too small.

- 7.3.2 All tanks shall be installed in accordance with the manufacturer's instructions and the standard to which the tank has been manufactured.

  B139-15 6.3.2

  Hydraulic drain hose installed on tank.

- 7.3.4 The end or side of a supply tank shall be at least 50 mm (2 in) from a wall. See Figure 9.

  B139-15 6.3.6(a)

  One tank is too close to wall.

- 7.3.5 Supply tanks shall be installed so that there is at least 460 mm (18 in) clearance along one side and one end, ensuring clearance for service of any device attached to the supply line at the tank. See Figure 9 for an illustration of tank clearances. NOTE: The certification label on the tank should be visible after installation.

  B139-15 6.3.6(a)

  One tank does not have 18" clearance along one side.

- 7.3.6 When supply tanks are installed adjacent to one another, the space between the tanks shall be at least 100 mm (4 in), unless certified otherwise. See Figure 9.

  B139-15 6.3.6(b)

  Less than 4" between tanks.

- 7.3.8 A tank shall be

  (a) installed on rigid, non-combustible supports constructed of materials having a fire-resistance rating of not less that 2 h; and

  (b) securely supported to prevent settling, sliding, toppling, or lifting. Tank supports constructed of steel need not be protected if the tank bottom is less than 300 mm (12 in) high at its lowest point.

  B139-15 6.3.3

  Other sites: Tank legs are too high.

- 7.3.10 A tank shall:

  (c) if installed with a bottom outlet, be pitched towards the outlet with a longitudinal slope of not less than 1 in 50. A clearance of 100 mm (4 in) is considered sufficient for single wall tanks. Bottom connections with sloped supports are preferred for metallic tanks to minimize the accumulation of water in the bottom of the tank.

  B139-15 6.3.7(a)

  Clearance criteria is not met.

- 7.4.1 When installed inside a building, supply tanks(a) not larger than 45L (10 gal) shall be specifically approved for the purpose; or(b) larger than 45 L (10 gal) shall be constructed in accordance with Clause 7.2.1.

  B139-15 6.2.1.1

  No ULC listing located on the day tanks

- 7.4.8 The tank shall be located and operated so that the

  (a) temperature of the oil in the tank does not exceed 38° C (100° F);

  (b) horizontal distance from the tank to any fuel-fired appliance, other than a combustible-fuel-oil-driven internal combustion engine, is not less that 0.6 m (2 ft.), except when approved as part of an appliance or as permitted by Clause 10; and

  (c) tank installation does not interfere with the required working space of any electrical panel or apparatus. A minimum working space of 1 m with secure footing shall be provided.

  B139-15 6.2.3.2.1

  Unknown temperature in the day tank

- 7.9.2.1 Normal venting and emergency venting of an auxiliary supply tank (day tank) shall be (a) through an overflow pipe; or (b) installed directly to the outside and provided with two independent means of level control to shut off fuel supply to prevent overfilling of the auxiliary supply tank. NOTE: For CAN-LUC-S602 tanks and ULC ORD-C80 tanks, the normal and emergency venting are combined. B139-15 10.6.1 Big Trout: Level control does not meet the requirements of this code.

- 7.10.2 All tanks installed inside a building shall be provided with

  (a) a gauge that meets the requirements of ULC ORD-C180;

  (b) a device that meets the requirements of ULC ORD-C180 or ULC ORD-C58.15, to indicate at the point of filling when the liquid level in the tank has reached a predetermined

  (c) both the gauge and the device specified in items (a) and (b)

  B139-15 6.5.2

  Day tank sight glasses do not meet the requirements for liquid level gauges or devices.

- 7.10.5 A glass sight gauge or other gauging device that penetrates the tank shell shall not be fitted in a location that can

  (a) permit a discharge of oil from the tank at the normal liquid level within the tank; or

  (b) interfere with the operation of the vent alarm if the gauge were broken.

  B139-15 6.5.5

  Day tank sight glass could allow discharge at normal liquid level.

- 7.13.2 Tanks that directly supply engines shall be

  (a) double bottom;

  (b) double wall; or

  (c) a minimum 300^{o} integral secondary containment with monitoring of the interstitial space.

  B139-15 6.2.1

  Day tanks do not meet these criteria.

- 7.13.5 Where the engine fuel supply is from an auxiliary tank, the auxiliary tanks hall be equipped with an approved overfill protection device. The approved overfill protection device shall

  (a) result in the fill line pump(s) being shut off at a maximum fuel storage capacity of 90% of the volume of the auxiliary supply tank; and

  (b) be equipped with a separate circuit that will result in all the power to the fuel pumps being turned off should the liquid level in the tank reach 95% of the storage volume.

B139-15 6.2.3

Big Trout: Overfill protection not approved and not adequate.

- 7.14.2 Where the fuel being returned from the engine to the tank is at a temperature higher than 38° C (100° F),

  (a) the return line shall be connected to a drop tube that extends to a maximum of 15 cm (6 in) from the bottom of the tank; or

  (b) a cooling system shall be equipped on the return line from the engine that would result in the fuel being returned to the tank at a temperature lower than 38° C (100° F). NOTE: See Clause 7.5.7.

  B139-15 5.1.3

  These tanks do not have drop tubes.

- 7.14.3 The fuel lines from the tank to the engine shall enter the supply tank or auxiliary supply tank through fittings located on the top centerline of the tank.

  B139-15 6.2.2

  Non-compliant.

- 9.3.1.1 All piping and tubing, except as restricted in Clause 9.3.1.2 and permitted by Clause 9.3.1.4, shall be

  (a) new;

  (b) standard-weight wrought iron, steel or brass pipe;

  (c) brass, copper, or steel tubing; or

  (d) the equivalent with respect to strength, durability, and resistance to corrosion and temperature.

  B139-15 5.2.1.2

  Vent is copper.

- 9.3.4 Piping and tubing joints and connections shall be made in accordance with the following:

  (a) joints and connections shall be made fuel-oil-tight.

  (b) joints and connections shall be made with standard pipe fittings or by welding. All standard screwed fittings shall be malleable and shall comply with ANSI/ASME B16.3.

  (c) Welding connections shall be made by a welder acceptable to the authority having jurisdiction.

  (d) A joint in seamless copper, brass or steel tubing shall be

  (i) made by means of flare joint or approved fitting; or

  (ii) brazed with a material having a melting point exceeding 540° C (1000° F).

B139-15 5.3

Some black iron fittings present, don't comply with the regulation

- The current operating conditions (noise) at Big Trout DGS are non-compliant with noise levels specified in the Environmental Compliance Approval (ECA). The following is required to meet the ECA:
  - New mufflers and exhaust systems on A and B units,
  - New air intake silencers on A and B room
  - New radiators or fans on all four units (including backup unit)
- Inside Unit-A building the cable trench/sump was not concrete. Instead, it was old timber and exposed soil. A-Unit does not have secondary containment. If a spill were to occur in Unit A building the flammable liquid would escape to the natural environment through this low-lying area. Also, the site is all graded downwards from the generator rooms so a significant spill would cause a lot of flammable liquid to saturate the soil/groundwater on-site and flow off-site in the direction of the staff house.

ATTACHMENT 2: BIG TROUT LAKE DGS - SAFETY ISSUES

Exposed 600V in Generator Control Cabinets

Generator control cabinets are meant for low voltage only. High voltage components are typically housed in a separate compartment in the switchgear. Big Trout Lake's switchgear is of an old design where the 600V breaker with exposed lugs is housed within the generator control cabinets. This is a safety hazard for personnel. New switchgear is required to eliminate this hazard. The existing control room as seen in Figure 2 is not large enough for new switchgear so a building addition would be required to house the switchgear.

***Figure 2**: Generator Control Cabinet – Existing Control Room.*

Switchgear Loading

The load in Big Trout Lake has approached the rating of the switchgear. In the summer of 2020, the control room became so hot that doors had to be left open and fans were pointed at the switchgear components to prevent them from overheating. This is a fire hazard. Similar to the exposed 600V issue, new switchgear in a new building addition would be required to rectify the loading issue.

Lifting Devices

The station does not have overhead cranes and they cannot be installed due to low ceiling height. Portable gantry cranes are used during maintenance but are not as safe as an overhead crane. The modular station will allow a container to be shipped back to Thunder Bay for overhaul (if required) in a shop, thereby eliminating concerns with lifting heavy engine components.

ATTACHMENT 3: BIG TROUT LAKE DGS - ENVIRONMENTAL ISSUES

Fuel System Piping

One audit finding indicated piping material not allowed by the fuel code. All of the yellow pipes in the arrangement near the bottom of Figure 3 are non-compliant copper. This represents a leak and fire hazard. No other Remotes station uses copper pipe. All of this pipe, the day tanks, and some other fuel piping in the station require replacement to meet fuel regulations.

***Figure 3**: Fuel System Piping.*

"A" Generator Room Containment

The floor and genset base in the A unit room are comprised of metal plates on wood joists sitting on earth. There is no spill containment. Any fuel or coolant spill inside the room will end up in the ground.

This is one of only two generator rooms remaining in Remotes' DGS's without a spill-containing concrete floor. The other is in Weagamow and will be decommissioned when connected to the grid in 2022. All other generator rooms that had wood floors were either replaced with concrete or turned into a dry storage room. Remotes has not installed a new engine in a room without containment in over 20 years. The cost and effort to remove the wood floor and replace with a concrete floor was found to be high during an upgrade in Fort Severn. In the Big Trout Lake case, the room would still be smaller than typical for a 600 kW generator, which affects operating and maintenance. The only acceptable solution is to house the new generator in a new building.

***Figure 4**: Unit A Generator Room Flooring.*

Environmental Compliance Approval (ECA) non-compliance

Noise compliance is enforced by the Ontario Ministry of Environment, Conservation, & Parks (MECP). The noise at the nearest receptor (i.e., a house) must be within limits. The Big Trout Lake DGS is too loud at the nearest receptor and a consultant determined that to meet the noise threshold, new radiators, new exhaust on two units, and new ventilation silencers on two units would be required. These are substantial changes. The ventilation silencers are large and heavy which would require additional support to be installed inside the walls. Quieter mufflers would be much larger than the existing and therefore would require new exhaust towers which would need to sit on new concrete foundations.

ATTACHMENT 4: BIG TROUT LAKE DGS – MODULAR STATION OVERVIEW

Modular Station Layout

The modular diesel generation station consists of a common corridor connecting three identical modular generators and a modular control room, as shown in Figure 5.

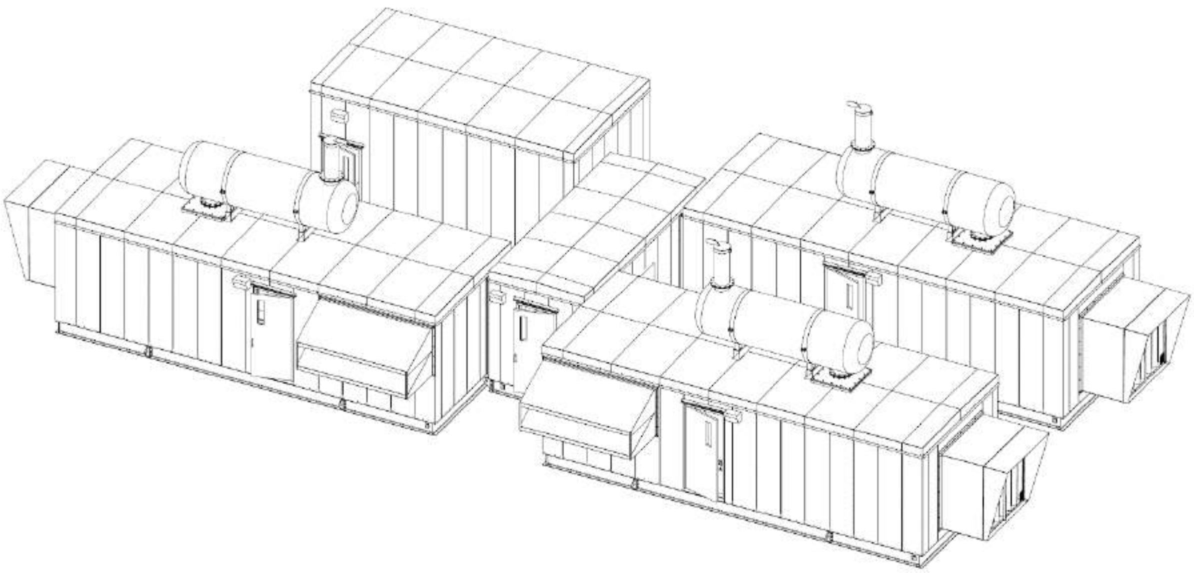


***Figure 5**: Modular Station Layout.*

Modular Generator Container Layout

The modular generator containers house all of the components required for the generator to operate. The only external connections are fuel from the existing bulk fuel farm, and power and control cables to the control room. The container layout is shown in Figure 6.

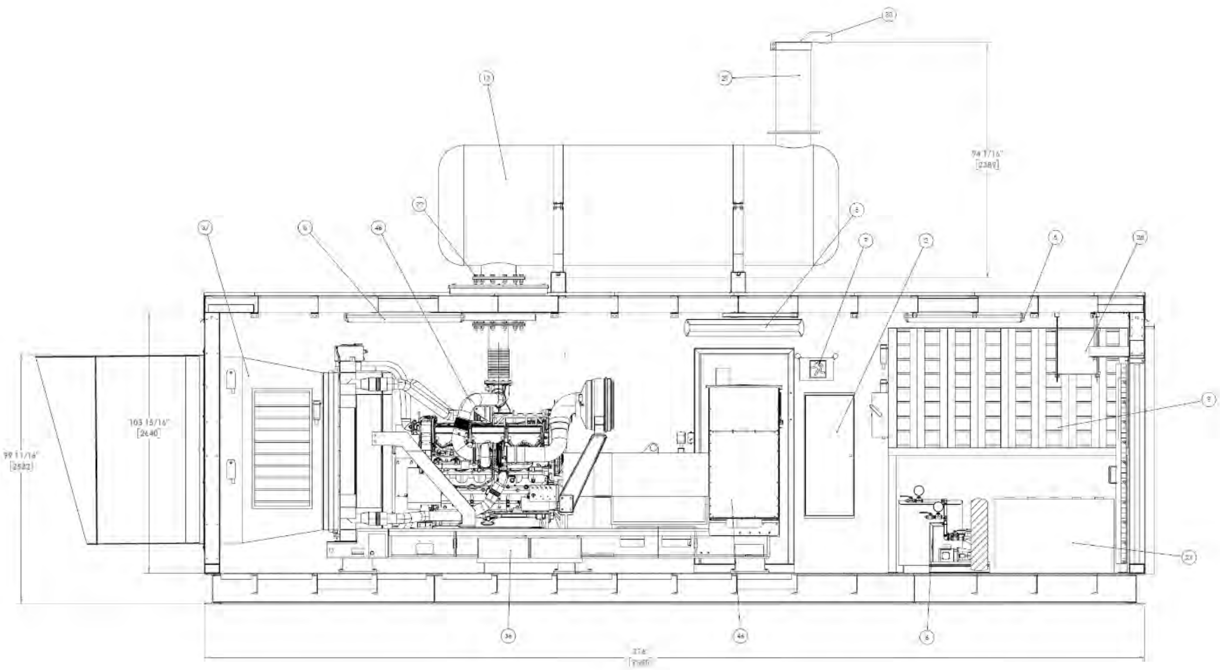


***Figure 6**: Modular Generator Container Layout.*

Site Layout

The modular station will be installed adjacent to the existing DGS, within the existing compound, as shown in Figure 7.

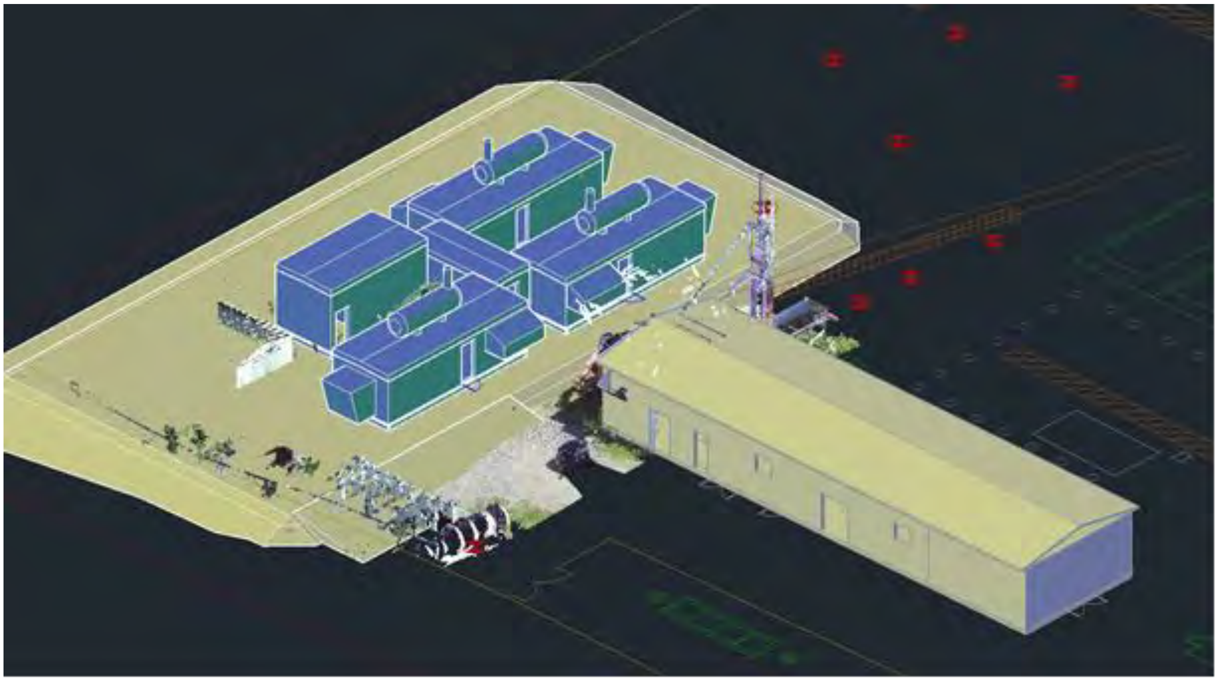


***Figure 7**: Modular Station Site Layout.*

Material Investment Narrative

Lansdowne House (Neskantaga) C Unit Generator Replacement

INVESTMENT SUMMARY	
Main Driver:	Failure Risk
OEB RRF Outcomes:	Customer Focus, Operational Effectiveness

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Cost	296	1,175	0	0	0

Summary:

This investment involves the planned replacement of the Lansdowne House Unit C generator. The C Unit generator has been assessed in fair condition and is forecast to exceed the 60,000 engine-hour threshold limit by 2024. As the community of Lansdowne will not be grid connected to the Watay Project, the replacement of the generation unit is critical to reliability of supply for existing customers.

By proactively addressing the condition of the generator, this investment is expected to mitigate failure risks to generation supply; and to support effective operation of the Lansdowne House DGS, which will be the only source of electricity for the community in the years to come.

A. General Information on the Project/Program

1. Overview

Portions of the Lansdowne House (Neskantaga) diesel generation station (DGS) were built between the 1980's and late 1990's and currently contain 3 diesel generators: Lansdowne House A, C and D. The plant currently supplies electricity to over 112 customers in the community of Lansdowne. This community will not be grid-connected when the Watay Transmission Project comes online, and as a result, these units are critical and are required to supply electricity to the community for years to come. The engine size, speed, vintage, condition and current and forecast engine hours are summarized in Table 1.

Table 1: *Engine Condition of Generators in Lansdowne House DGS*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition[2]	Engine Hours[3]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Lansdowne House A	275	1,800	2019	Very Good	2,813	5,077	7,341	9,605	11,869	14,133
Lansdowne House C	600	1,800	2014	Fair	49,104	54,945	60,826	66,706	72,586	78,467
Lansdowne House D	600	1,200	1999	Very Good	19,518	20,687	22,322	23,957	25,592	27,227

[1] In-service year corresponds to the year the unit was installed.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The last condition assessment was carried out in November 2021.
[3] Engine-hours shown are current as of February 8, 2022.

The manufacturer's published recommendations for medium-speed generators (1,800 rpm) include complete overhauls after 20,000 hours, and Remotes has a policy that generators of this type shall be replaced once they reach the threshold for a third overhaul, generally at about 60,000 engine-hours. In addition, the units are inspected and maintained every 2,500 hours to determine the condition. The Lansdowne House C Unit is in fair condition and is forecast to exceed the 60,000 engine-hour threshold by 2024. Therefore, an engine replacement has been scheduled for this generator in 2024, with the procurement of the replacement generator to take place in 2023. Assets are often ordered and transported to site a year in advance, to mitigate transportation risks (e.g., bad weather conditions & winter road availability) and long lead times.

Remotes plans to invest $1.471M to complete the replacement of the Lansdowne House C Unit. The replacement will be like-for-like, and the new unit will be compliant with the latest standards. This project is necessary to ensure continued delivery of safe and reliable electricity to the community. An image of the existing generator is shown in Attachment 1.

2. Timing

i. Start Date: March 2023

ii. In-Service Date: November 2024

iii. Key factors that may affect timing: As a result of the remote location of the Lansdowne House DGS, Remotes must time the work such that the winter road is available to transport the unit to site. A delay in receiving the necessary materials and equipment could delay the project by up to a year when the road is available again. The availability of resources needed to complete the project can also impact timing.

3. Historical and Future Capital Expenditures

***Table 2**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	0	296	1,175	0	0	0	1,471
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	296	1,175	0	0	0	1,471

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Typical generator replacements will require a new radiator, a complete aftercooler piping circuit, an upgraded exhaust system, and electrical control and power upgrades. Since Remotes is proposing a like-for-like replacement, the scope associated with this project is smaller than the scope associated with a typical engine replacement project since the radiators are correctly sized, the appropriate aftercooler circuit is already in place, and the exhaust is correctly sized. Only the controls may need an update depending on the compatibility of the newer engine controller. As a result, the cost associated with this project will be less than a typical generator replacement project, however other factors such as increases in material costs and inflation may also affect the overall cost.

The Lansdowne House C Unit like-for-like replacement is expected to cost $1.471M. In order to compare the cost to other similar generator replacement projects, cost per kW can be considered. The new 1,800 rpm generator unit will have a capacity of 600 kW, rendering the cost per kW at $2,452.

A generator replacement of similar scope was completed at Marten Falls in 2018, where a new 1,800 rpm generator unit with capacity of 400 kW was installed at the total cost of $1.43 M, and per-kW cost of $3,575. The observed cost differences can mostly be attributed to the difference in unit size and the greater level of piping work that was required as part of the Marten Falls project.

6. Investment Priority

This is a high priority project as it is integral in maintaining reliable prime-power generation in Lansdowne which is not being grid-connected. This DGS will be the only source of electricity for the community for years to come.

7. Alternatives Analysis

Remotes has considered the following options when determining the most appropriate option for the Lansdowne House C Unit:

- Option 1: Do Nothing – This is not a viable alternative as it would jeopardize the reliable electricity supply to the community.
- Option 2: Rebuild Engine – The C unit has already been overhauled twice. Rebuilding the engine a third time will result in decreased reliability and will increase the risk of safety and environmental spill incidents. As a result, this is not a viable option for long-term use.
- Option 3: Replace Engine (Selected Option) – Remotes' extensive experience with generators provides knowledge that after a third overhaul, engines are inherently less reliable and no longer perform satisfactorily. They have more wear on the block and crankshaft (parts that are not replaced during an overhaul) that will cause oil leaks, coolant leaks, and other issues that will require increased maintenance effort and costs. As these generators are critical sources of electricity for these remote communities, it is imperative to ensure these generators continue to function safely and reliability, and therefore Remotes has identified an engine replacement as the only viable option.

8. Innovative Nature of the Project

Engine replacements are routine in nature and are not considered innovative for Remotes. The new engine will be compliant with the latest standards.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 3**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Newer units offer improved efficiency relative to the vintage units they replace. The new unit will also require less maintenance and repairs than the existing unit, thereby minimizing maintenance costs for the station. This in turn allows Remotes to direct staff to other critical maintenance and capital projects.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	Installation of a newer, more reliable unit allows Remotes to continue providing a reliable source of electricity supply to the community. Remotes will also benefit from the reduced maintenance costs for the station.
Reliability	Reliability of the new unit will be better relative to the existing unit that has been rebuilt multiple times. Old engines are also more prone to catastrophic failures which, besides being a safety and fire risk, would affect reliability for months until a permanent replacement unit could be installed.
Safety	New units are inherently safer than old, nearly worn-out units. There are less chances for failures and leaks which could cause safety and fire issues.

2. INVESTMENT NEED

i. Main Driver**:** Failure Risk – The Lansdowne C unit is an old unit on its second engine build that is approaching the 60,000 operating hour threshold and is therefore more prone to failure. A failure of this unit would significantly impact Remotes' customers who rely on these units as their only source of electricity*.*

ii. Secondary Drivers*:* It is Remotes' policy, based on manufacturer's information and past experience, to replace generators when the engine requires a third overhaul. This is the case with this unit, as it has already had two engine rebuilds. New engines are also more energy and fuel efficient and produce less air pollutants.

iii. Information Used to Justify the Investment: For the last 10 years, Remotes' generator policy has been used to help guide unit replacements. The policy is based on extensive maintenance and operating experience, consultation with other off-grid utilities, and manufacturer's recommendations. This policy is also a fundamental element of Remotes' AM process for diesel generators. Additional information on manufacturer recommendations and Remotes generator policy is included below, and further information on Remotes' generation AM process can be found in Section 5.3 of the DSP.

Manufacturer's Recommended Overhaul Interval

Figure 1 shows a representative maintenance overhaul schedule from Caterpillar. This chart recommends a major overhaul at 27,000 hours but that is at a 51% load factor. Prime power generators typically run in the 60-70% load factor range. Toromont (Caterpillar's Ontario representative) recommends 20,000-hour intervals for major overhauls and all Canadian utilities use the 20,000-hour major overhaul interval for their 1,800rpm generators.

Service Hours and Fuel Consumption for the 3512C Engine		
Interval	Fuel Consumption[1]	Fuel Consumption[2]
250 Service Hours	32980 L (8712 US gal)	41534 L (10972 US gal)
500 Service Hours	65960 L (17425 US gal)	83067 L (21944 US gal)
1000 Service Hours	131921 L (34850 US gal)	166138 L (43889 US gal)
2000 Service Hours	263842 L (69700 US gal)	332275 L (87778 US gal)
3000 Service Hours	395765 L (104550 US gal)	498414 L (131667 US gal)
6000 Service Hours	791526 L (209099 US gal)	996824 L (263333 US gal)
Top End Overhaul	1187291 L (313649 US gal)	1495238 L (395000 US gal)
	9000 Service Hours	
Second Top End Overhaul	2374581 L (627298 US gal)	2990475 L (790000 US gal)
	18000 Service Hours	
Major Overhaul	34000 Service Hours	27000 Service Hours
	4485713 L (1185000 US gal)	

[1] Based on 39 percent load factor.
[2] Based on 51 percent load factor.

***Figure 1**: Manufacturer's Maintenance Overhaul Schedule.*

Remotes' Generator Replacement Policy

Although overhaul interval recommendations are provided, generator manufacturers do not publish recommended replacement intervals. However, in 2010, Remotes implemented a policy to replace 1800rpm generators when they reached their third overhaul interval (60,000 hours). The policy is based on Remotes' extensive experience with prime power generators. Remotes found that parts which are not replaced during an overhaul (engine block, crankshaft, camshafts) showed significant wear by 60,000 hours. When generators were run beyond 60,000 hours, this wear had proven to increase breakdowns and thereby affected customer reliability. For reference, 60,000 hours is equivalent to approximately two-million miles for a transport truck engine, which is well beyond their typical lifespan.

As the current Lansdowne C unit engine has been rebuilt twice already and has over 60,000 operating hours, it is at the point of failure and in need of rebuilding, the generator should be replaced as per Remotes' policy.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: This project is required to maintain the reliability of the electrical supply to the community. Justification for this project is identical to many generator replacement projects completed by Remotes over the past 10 years, and Remotes' plan is based on similar investment and is considered good utility practice. All new installations will also comply with O. Reg. 22/04.

ii. *Cost-Benefit Analysis:* The alternatives will not ensure a safe and reliable electrical supply and thereby could affect the wellbeing of the community. The generator replacement is the only alternative that has the benefit of ensuring a reliable electrical supply in Lansdowne House.

iii. *Historical Investments & Outcomes Observed:* Generator replacements have shown to improve reliability and decrease maintenance costs compared to overhauling engines a third time. Historical generator replacement costs are listed in section 5 of section A of this document.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. Conservation and Demand Management

Community demand reduction from CDM would not mitigate the lower reliability, higher maintenance costs and safety risks associated with running a high-hour engine. As a result, no viable CDM alternative has been identified for this project.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

Similar generator replacements have been completed by Remotes many times, so this is not considered an innovative project.

ATTACHMENT 1: LANSDOWNE C UNIT PICTURES

Figure 2 shows the Lansdowne C unit in 2015.

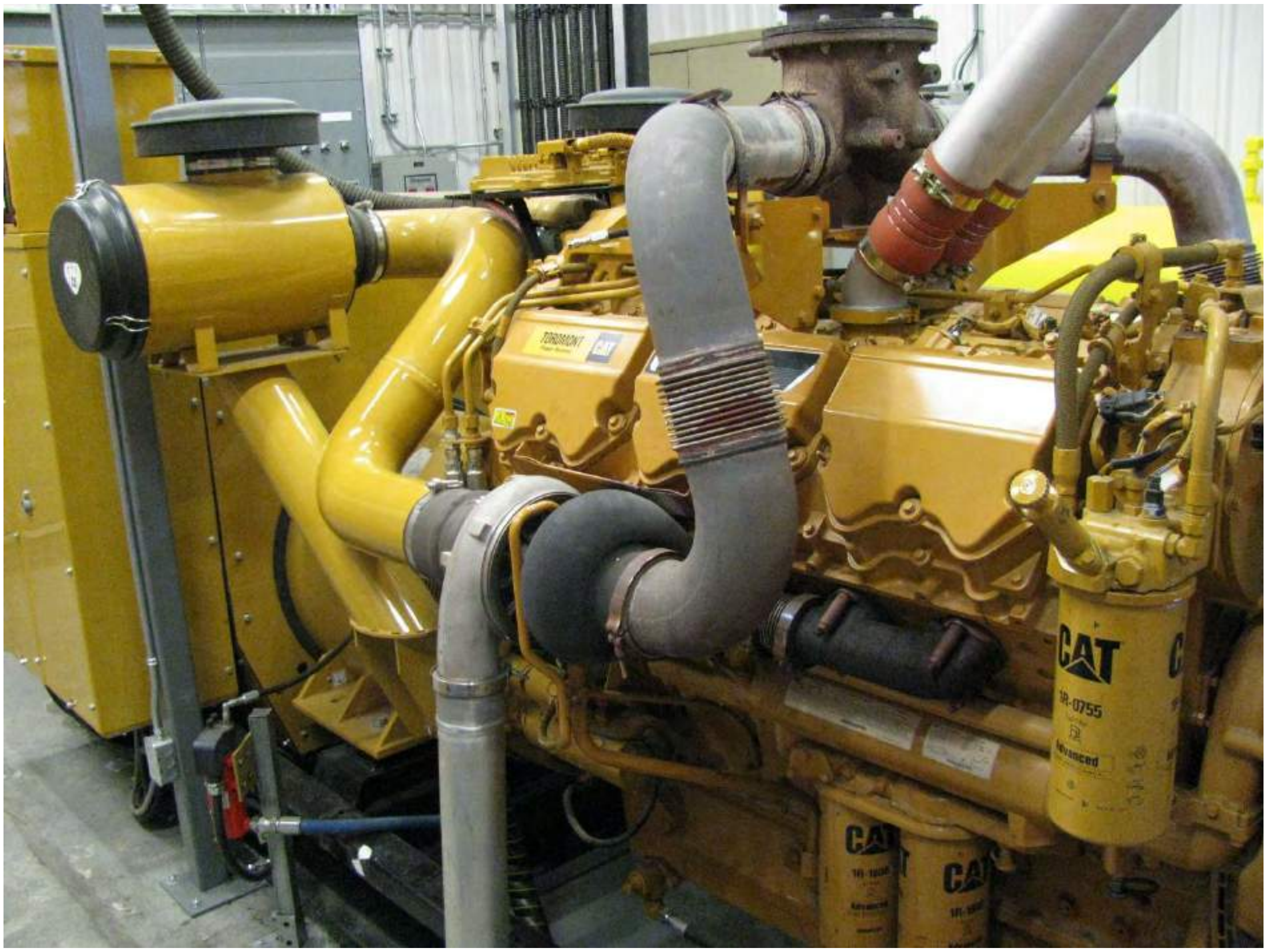


***Figure 2**: Lansdowne C Unit.*

Material Investment Narrative

Lansdowne House (Neskantaga) Bulk Tank Replacements

INVESTMENT SUMMARY

Main Driver:	**Regulatory Obligations**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness, Public Policy Responsiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	394	391	0	0	0

Summary:

This investment involves the planned replacement of two 50,000L bulk fuel tanks that are not compliant with current fuel regulations and are also assessed to be near end-of-life. Non-compliance with regulations will result in the need for additional fly-in fuel, to meet community generation demand.

By proactively addressing the non-compliance and condition issues, this investment is expected to mitigate reliability risks to fuel supply and support effective operation of the Lansdown House diesel generating station.

A. General Information on the Project/Program

1. Overview

The Lansdowne House (Neskantaga) diesel generating station (DGS) has five 50,000L bulk fuel tanks, totalling 250,000L, that store and supply fuel to the DGS to produce electricity. Lansdowne House DGS uses, on average, 20,000L per week. These tanks typically hold up to 10 weeks of fuel supply, while maintaining minimum levels.

All of Remotes' sites are audited as part of Remotes' Environmental Heath & Safety Management System (EHSMS). The Lansdowne House audits have found that two of the bulk fuel tanks (Tanks 1 & 2) do not have a manufacturer's nameplate installed which means there is no proof that the tanks have the necessary certifications to hold fuel and comply with Underwriters Laboratories of Canada (ULC) standards. This is a violation of fuel regulations. An excerpt from the EHSMS audit findings identifying this issue is shown in the following table.

***Table 1**: Summary of EHSMS Audit Findings*

Review Protocol	Item	Finding	Recommendation	Action
Fuel	**14.1** Approved standards of design and construction are used, but not be restricted to, (a) the following ULC Standards: (vi) ULC-S601; (vii) CAN/ULC-S603; (viii) CAN/ULC-S603.1; (ix) S615; (x) S630; (xi) CAN/ULC-S643; and (xii) S653; (b) API Standard 650;	Tank 3, 4 & 5 ULC approved. No plates on Tanks 1 & 2	Need to confirm ULC approvals for Tanks 1& 2	Confirm manufacture tanks certification & get nameplates installed
Fuel	**16.3** The double-wall AST system with a maximum capacity of 50 000 L conform to ULC Standards S653.	Tanks 1 & 2 have no plates to confirm, see 14.1	Should validate ULC standard	Confirm manufacture tanks certification & get nameplates installed

Remotes has contacted the tank manufacturer for assistance to confirm whether the manufacturer could recertify the existing tanks and supply new nameplates. However, the manufacturer was not able to not find any records of the tanks in question, and as a result was not able to provide a new nameplate or recertify the tanks.

Based on the timing of previous upgrades, Remotes has some certainty that Tanks 1 & 2 are 1990's vintage. Fuel tanks of this vintage are at or approaching end-of-life[1] and would require inspection, testing and re-certification for further long-term use (see Attachment 1 for pictures of existing tanks). Continuing to use older fuel tanks also increases failure risk associated with the

[1] There is no defined lifespan for these types of fuel tanks, but 25 years is their expected life.

tanks, which in turn poses environmental and fuel storage and supply risks. Lansdowne is not part of the Watay Project, so suitable long-term fuel storage capacity is a must.

Remotes is requesting $785,000 to replace Tanks 1 & 2 with two new 50,000L certified tanks that comply with all necessary standards. The new tanks will also eliminate the risk associated with continuing to use the older fuel tanks. The new tanks will also have engineered platforms on each side and a full safety railing. This will be a safety improvement over the existing tanks, that have a non-engineered platform on one side of the tank, and bring them up to meet the latest standards, which have evolved significantly since their initial installation.

2. Timing

i. *Start Date:* June 2023

ii. *In-Service Date:* September 2024

iii. *Key factors that may affect timing:* Remotes has to time the work such that the winter road is available to transport the tanks to site. If there is a delay in any materials or the supply of the tank from the manufacturer this could delay the project by up to a year when the road is available again.

3. Historical and Forecast Capital Expenditures

***Table 2**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ ‘000)				Bridge Year	Test Year	Forecast Costs ($‘000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	0	394	391	0	0	0	785
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	394	391	0	0	0	785

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The replacement of a 50,000L capacity bulk tank was completed in Hillsport in 2017 for $475,000, amounting to a per unit cost of approximately $9.5/L. Due to economies of scale, the cost to replace two 50,000L tanks at Lansdowne is less on a per unit basis. Replacement costs are estimated at $785,000 for the two tanks, which amounts to a per unit cost of $7.85/L.

6. Investment Priority

This is a high priority investment. The tanks were undoubtedly certified when new, so the risk of a spill is no higher than for a similar vintage tank. However, these tanks are currently in violation of fuel regulations, pose increased risk based on age, and will continue to be a finding in future audits unless the tanks are replaced. It is therefore a high priority to replace these tanks in order to comply with the latest fuel regulations.

7. Alternatives Analysis

The following options have been considered in determining the proposed solution:

- Option 1: Do Nothing – Doing nothing would mean continuing to use tanks that are in violation of fuel regulations and that do not follow the principles of the EHSMS system. Remotes must address all fuel system findings resulting from the audits in order to be compliant. Doing nothing is not a viable option. End of asset life and long-term need is also not addressed.
- Option 2: Recertification of the Tanks – Remotes has reached out to the tank manufacturer to confirm whether it is possible to recertify the existing tanks and install new nameplates. The manufacturer confirmed that they have no records of the two tanks in question, and as a result, the manufacturer is not able to recertify the tanks or supply new nameplates.
- Option 3: Install a Larger and Fewer Tanks – While above ground tank sizes can range up to 70,000-80,000L, it is more challenging and costly to transport and install larger tanks, particularly via winter road travel. One larger tank would also not provide sufficient capacity to replace the two 50,000L tanks with a total capacity of 100,000L. The current 50,000L size is common across Remotes' fleet and is easier to transport and install. As a result, this option was discarded.
- Option 4: Replace Tanks Like-for-Like (Selected Option) – A like-for-like replacement of the existing two tanks is the preferred option as these tanks are required to ensure sufficient fuel is available to continue operating the DGS in between the refilling of tanks. The new tanks will be certified and comply with all applicable standards and regulations.

8. Innovative Nature of the Project

There is nothing innovative for Remotes in this project. Remotes has completed similar replacement projects successfully in recent years.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 3**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Efficiency of the DGS will not be affected by this project. However, Remotes is planning to coordinate the replacement of both tanks at the same time to optimize efficiency and cost effectiveness.
Customer Value	If the uncertified tanks were flagged by fuel regulators (Technical Standards and Safety Authority, "TSSA") and directed to not be used, additional fly-in fuel would be required which would raise fuel costs that in turn are paid for by customers through rates. Replacing the uncertified tanks with new certified tanks will ensure continued supply of electricity to communities while maintaining affordability for customers.
Reliability	Reliability of the DGS will not be affected. However, the new tanks will eliminate the failure risk associated with continuing to use the older fuel tanks, which in turn will reduce the environmental risk and allow for continued reliable storage and supply of fuel to operate the DGS.
Safety	New tanks will have engineered platforms that will improve employee safety compared to the existing tanks. New tanks and associated fuel system components are also less prone to leaks or spills relative to older vintage tanks.

2. Investment Need

i. Main Driver: Regulatory Obligations – Remotes is obligated to ensure that its fuel tanks have the correct certifications to safely store and supply fuel and comply with all applicable standards and regulations. Currently two of the tanks at Lansdowne House are nearing end of life, have no clear nameplate and cannot be certified. Investment in new certified tanks is required to allow for continued storage and supply of fuel to operate the DGS and supply reliable and affordable electricity to the community of Lansdowne.

ii. Secondary Drivers*:* Failure Risk & Safety are secondary drivers for this project.

   a. Failure risk: Based on the timing of previous upgrades, Remotes has some certainty that Tanks 1 & 2 are 1990's vintage. Fuel tanks of this vintage are at or approaching end-of-life and will require inspection, testing and re-certification for further long-term use. Continuing to use older fuel tanks also increases failure risk associated with the tanks, which in turn poses environmental and fuel storage and supply risks. Lansdowne is not part of the Watay Project, so suitable long-term fuel storage capacity is a must.

b. Safety: the existing tanks do not have an engineered platform on each side, nor an engineered safety railing. The new tanks will have this and meet the latest safety standards.

iii. Information Used to Justify the Investment: Remotes regularly undertakes EHSMS audits and implements the necessary actions to satisfy audit findings as part of its focus on continuous improvement. This is done to ensure continued compliance with all applicable standards and regulations so that Remotes can continue providing safe and reliable electricity to customers. Remotes also conducts regular inspections and maintenance on tanks and associated equipment. Inspections and maintenance history are key inputs into Remotes' AM process, which is detailed further in Section 5.3 of the DSP.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: Compliance with fuel regulations is necessary. When it is found that parts of fuel system do not meet regulations, Remotes takes the necessary steps to bring the system into compliance.

ii. *Cost-Benefit Analysis:* The other alternatives of do nothing or recertification (which has been confirmed as not possible) are not viable as they would not rectify the compliance issue. While Remotes could install larger tanks in theory, this is not recommended due to the logistics and costs of transporting these tanks on winter roads.

iii. *Historical Investments & Outcomes Observed:* Remotes has successfully replaced a number of bulk tanks historically. Historical replacements have been driven by a number of factors, including increased fuel and storage requirements, uncertified fuel systems, and end of life tanks. In all cases, replacements have met their intended outcomes and continue to perform as expected.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. Conservation and Demand Management

CDM is not applicable for this project.

i. *Project Deferrals*: This is not applicable.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

This project has no innovative components for Remotes. All of the technology has been used in previous projects and has been proven to work.

ATTACHMENT 1: LANSDOWNE HOUSE TANK IMAGES

Pictures of the Lansdowne House tanks taken in 2007 are included in Figure 1 and Figure 2 below. The subject Tanks 1 and 2 are shown at the far end of Figure 1, and the non-engineered platforms and railings on only one side of the tanks are also visible in the pictures. As can be seen in these pictures, the tanks were showing their age even 15 years ago.

Figure 1*: Lansdowne House Tanks*

***Figure 2**: Lansdowne House Tanks - Platforms and Railings*

Material Investment Narrative

Lansdowne House (Neskantaga) DGS Upgrade

INVESTMENT SUMMARY	
Main Driver:	**Capacity Constraints**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	0	0	0	0	0

Summary:

Diesel generation station (DGS) capacity upgrade investments address system capacity issues that arise from community load growth. This investment involves the upgrade of the Lansdowne House A generation unit with a new 1,000 kW unit which, along with two other units, supply electricity to over 112 customers in the community of Lansdowne. The peak station load at Lansdowne House reached 703 kW in 2020, nearing its connection restriction limit of 744 kW, or 85% of the station prime rating. Since the community of Lansdowne will not be grid connected to the Watay Project, a capacity upgrade of the Lansdowne House Unit A generator has become critical to reliability of supply for existing customers as well as forecast community load growth. The existing generation unit A will be decommissioned, and either be reused, placed into storage to be used as a spare unit or be auctioned off. The investment also replaces the step-up transformer. The Lansdowne House DGS upgrade costs are fully recoverable through a long-standing agreement with ISC.

The investment is expected to increase the Lansdowne House DGS prime rating from 875 kW to 1,200 kW and raise the connection limit to 1,020 kW. This investment addresses the capacity issue through the DGS upgrade, resulting in the continued ability of the system to meet forecast customer demand. By implementing this project, the customers in Lansdowne will be able to make new connections to the distribution system in order to add more housing and supply new critical infrastructure projects within the community.

A. General Information on the Project/Program

1. Overview

Portions of the Lansdowne House (Neskantaga) diesel generation station (DGS) were built between the 1980's and late 1990's and currently contain 3 diesel generators: Lansdowne House A, C and D. The DGS currently supplies electricity to over 112 customers in the community of Lansdowne. This community will not be grid-connected when the Watay Transmission Project comes online, and as a result, these units are critical and required to supply electricity to the community for years to come. The engine size, speed, vintage, condition and current and forecast engine hours are summarized in Table 1. Images of the Lansdowne service area and Lansdowne House DGS are included in Attachment 1.

***Table 1**: Engine Condition of Generators in Lansdowne House DGS*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition[2]	Engine Hours[3]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Lansdowne House A	275	1,800	2019	Very Good	2,813	5,077	7,341	9,605	11,869	14,133
Lansdowne House C	600	1,800	2014	Fair	49,104	54,945	60,826	66,706	72,586	78,467
Lansdowne House D	600	1,200	1999	Very Good	19,518	20,687	22,322	23,957	25,592	27,227

[1] In-service year corresponds to the year the unit was installed.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The last condition assessment was carried out in November 2021.
[3] Engine-hours shown are current as of February 8, 2022.

The electrical demand in remote communities is continually increasing due to new infrastructure, new housing, and population growth. The DGS capacity must be larger than the peak demand to ensure Remotes can provide reliable power. When peak demand reaches 85% of the DGS capacity, new electrical connections are restricted in the community to ensure Remotes can continue to provide reliable service to existing customers. Connection restrictions can lead to a shortage of housing and delayed connection of new community infrastructure (arenas, schools, etc.).

The peak station load at Lansdowne House reached 703 kW in 2020, nearing its connection restriction limit of 744 kW, or 85% of the station prime rating (875 kW), which is based on the smallest two units in service. The peak demand in Lansdowne House is also expected to surpass 85% of the DGS capacity by 2023, thereby enacting connection restrictions. This DGS upgrade is required so that the community is not negatively affected by insufficient electrical capacity. Not increasing the station capacity will reflect poorly on Remotes when new connections for important community needs cannot be provided.

Remotes is proposing to increase the capacity of the Lansdowne House DGS by replacing the existing 275 kW Unit A generator with a new 1,000 kW unit that will become the new largest unit within the DGS. In addition, new transformers will also be installed to accommodate the increase in the new capacity. The upgrade will increase the station prime rating from 875 kW to 1,200 kW. This will allow for peak load growth in the community past the forecasting horizon of 2034. The

Lansdowne House Unit A, as seen in Figure 4 of Attachment 1, was selected for the upgrade as it is the smallest generator at the station and is seldom able to supply the community demand. Since this unit is still in very good condition and has low engine-hours, this unit will either be reused, kept as a spare or be auctioned off. Remotes will assess the potential uses of the unit further once it is taken out of service.

The Lansdowne House DGS Upgrade project is expected to cost $2.606M. Capital upgrade costs are fully recoverable through a long-standing agreement with Indigenous Services Canada (ISC). Remotes provide an estimate for the upgrade work to the Lansdowne House First Nation, who will then apply for funding from ISC. Once the funding is in place, Remotes is able to start the design and order long-lead materials. Any changes to scope and cost are discussed with the first nation and pre-approved with the ISC with all Remotes' costs fully recoverable.

By implementing this project, the customers in Lansdowne will be able to make new connections to the distribution system in order to add more housing and supply new critical infrastructure projects within the community. This upgrade is consistent with ensuring customers' expectations for unrestricted connection to the distribution system.

2. TIMING

i. Start Date: January 2023

ii. In-Service Date: November 2024

iii. Key factors that may affect timing: The timing of this project is dependent on ISC approval for the capital dollars required. Remotes also has to time the work such that the winter road is available to transport the materials to site. If there is a delay in any materials, especially long-lead items from the manufacturer, this could delay the project by up to a year when the winter road is available again. In addition, Remotes has to ensure it has the correct resources available to complete the project and that resources can be safely transported to site. Any changes to scope and design could delay the project as any changes to funding have to be approved by the ISC. Any delays in receiving the necessary environmental regulatory approvals (air and noise emissions) can also affect the project timing.

3. HISTORICAL AND FORECAST CAPITAL EXPENDITURES

***Table 2**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	0	501	2,105	0	0	0	2,606
Contributions	0	0	0	0	0	(501)	(2,105)	0	0	0	(2,606)
Capital (Net)	0	0	0	0	0	0	0	0	0	0	0

This is a multi-year project with in-service date of November 2024. Remotes serves customers of First Nation reserves under funding agreements with ISC. Under these agreements, ISC pays for capital related load growth. As a result, the capital costs associated with this work is 100% recoverable.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The Lansdowne House DGS Upgrade project is expected to cost $2.606M. In order to compare the cost to other station upgrade investments, cost per kW can be considered. The new 1,800 rpm generator unit has a capacity of 1,000 kW, rendering the cost per kW at $2,606.

A DGS upgrade of similar scope was completed at Fort Severn in 2015, where a new 1,200 rpm generator unit with capacity of 1,000 kW was installed at the total cost of $3.6M, and per-kW cost of $3,600. The observed cost differences can mostly be attributed to the complete floor replacement that was required at Fort Severn, which is currently not a requirement for the Lansdowne House DGS Upgrade project.

6. Investment Priority

This is a high priority investment. Without this investment, prolonged connection restrictions will be required which will have a negative effect on the community.

7. Alternatives Analysis

Remotes has considered the following options:

- Option 1: Do Nothing – Doing nothing will mean prolonged connection restrictions for the community which will limit the future growth and development of the community. Even with connection restrictions, there is demand growth among existing customers that would put pressure on the DGS and decrease reliability of the electrical supply. As a result, doing nothing is not a viable option.

- Option 2: Demand Management – This is not a long-term solution. This is a growing and developing community, so increased electrical capacity will be required to satisfy that growth.

- Option 3: Incorporating Alternative Sources – The cost of incorporating alternative generation sources such as renewables is very high, and they do not provide the necessary level of reliability. Renewable generation sources are also intermittent and are unable to provide baseload energy on their own. As a result, this is not a viable option.

- Option 4: Increase the Lansdowne House DGS Capacity (Selected Option) – This option includes replacing the existing 275 kW Lansdowne House A unit with a new 1,000 kW unit. This option will increase the station prime rating from 875 kW to 1,200 kW and allow for peak load growth in the community past the forecasting horizon of 2034. The proposed scope and associated cost currently assume that the new unit will be installed within the existing room, however additional assessment is required to confirm whether this is feasible. If the community supports Remotes' proposed option, they will pass a Band

Council Resolution to request funding from ISC. Upgrading the DGS capacity is the preferred option for the community of Lansdowne House.

8. Innovative Nature of the Project

There is nothing inherently innovative to Remotes about this project.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 3**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	By replacing the old generator with a new one that incorporates the latest technology, both diesel generation efficiency and carbon emission intensity would be positively affected. In addition, operating a newer more reliable unit will reduce the probability of unplanned failures. This means less callouts for unexpected maintenance response, allowing staff to be redeployed to other critical maintenance and capital project tasks.
Customer Value	The DGS upgrade will allow the community to connect new housing and new infrastructure projects (e.g., school, arena, community centre, etc.) to grow and develop their community over the forecast period and beyond.
Reliability	Since this is a known growing and developing community, this upgrade will eliminate estimated connection restrictions until at least 2034 while maintaining levels of reliability. Without the increased capacity, community demand will approach and eventually surpass the capacity of the DGS. This would negatively impact reliability because the generators and auxiliaries would be running at/or beyond their design limit, which often causes failures. Newer units are also less prone to unplanned failures and thus have improved reliability and generator availability.
Safety	By implementing this project, the DGS will not be operating near its rated capacity and therefore will have less chance of failures that could impose safety and fire risks. All upgrades to generator PLCs and related infrastructure will also meet the latest cyber-security standards.

2. Investment Need

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load has surpassed 85% of the station rating. The forecast peak load for Lansdowne is shown below in

Table **4**.

***Table 4**: Lansdowne Forecast Peak Load*

Community	Connection Limit (kW)	Forecast Peak Load (kW)					
		2022	2023	2024	2025	2026	2027
Lansdowne House	744	652	763	775	786	798	810

The existing DGS capacity is not sufficient to accommodate forecast growth in the community. Without an upgrade, connection restrictions will be required to protect the electrical supply for existing customers. The project will allow the Neskantaga First Nation to build and connect adequate housing to meet growing demand and connect new infrastructure projects that are beneficial to community residents. Sufficient generating capacity allows Remotes to continue providing reliable service and not negatively impact SAIDI and SAIFI as would happen if community demand surpassed the DGS capacity.

i. Main Driver: Capacity Constraints – Based on current projections and known upcoming developments, community growth and development will be stifled without this project. This DGS capacity upgrade is required to accommodate the growth and development in the community over the forecast period and beyond.

ii. Secondary Drivers*:* Reliability – Reliability of the power supply to existing customers will be affected without a DGS upgrade. By upgrading the station capacity, the reliability can be maintained at current levels for customers.

iii. Information Used to Justify the Investment: The need for this investment was identified through annual peak load forecasts, which is a key input into Remotes' planning and asset management process, as well as through ISC and community consultations. The forecasts have shown increased demand year over year and that community demand will surpass the DGS connection limit by 2023. Additional information on Remotes' asset management process and peak load forecasts can be found in Section 5.3 of the DSP.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: Remotes' policy is to notify a community when their peak load reaches 75% of the DGS rating so they can prepare a funding request with ISC as they are responsible for capital upgrades to the DGS. It typically takes three years for a community to grow from 75% to 85% of the DGS rating, when connection restrictions are implemented. The 75% notification is meant to allow enough time to get the funding in place and complete the upgrade before connection restrictions are required to protect the electrical supply for existing customers. Even with connection restrictions, the demand from existing customers will continue to grow and will strain the DGS, affecting reliability. Upgrades ensure that stations are not loaded so highly that reliability is compromised. All necessary approvals for air and noise emissions will also be met for this project.

ii. *Cost-Benefit Analysis:* Alternatives will not allow Remotes to maintain the costs and electrical reliability for customers. A capacity upgrade is the only alternative that will allow Remotes to maintain the electrical reliability for existing customers while also accommodating new growth and development within the community.

iii. *Historical Investments & Outcomes Observed:* Remotes has undertaken similar DGS capacity upgrades in recent years. These investments have allowed continued growth and development within the communities which benefited residents. They also allowed Remotes to ensure dependable generation and reliability for existing customers.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. CONSERVATION AND DEMAND MANAGEMENT

i. *Project Deferrals:* CDM is not a long-term solution. Increased electrical capacity is required to accommodate the growing and developing community.

ii. *Cost-Benefit Analysis*: A capacity upgrade is the only alternative that will allow Remotes to maintain the electrical reliability for customers.

iii. *Use of Advanced Technology*: There is no advanced technology planned for this upgrade. Remotes is part of the Off-Grid Utilities Association (OGUA), a group of utilities that service off grid communities. Through that association and other interests, Remotes is not aware of any proven technology that can replace diesel generators for prime power at this time.

5. INNOVATION

There is nothing innovative in this project for Remotes.

ATTACHMENT 1: LANSDOWNE SERVICE AREA & DGS IMAGES

A map of the Lansdowne service area is shown in **Figure 1**.

***Figure 1**: Lansdowne Service Area Map.*

The Lansdowne House DGS is shown in Figure 2 and Figure 3 below.

***Figure 2**: Lansdowne House DGS Aerial View*

***Figure 3**: Lansdowne House DGS.*

The Lansdowne House Unit A generator is shown in Figure 4.

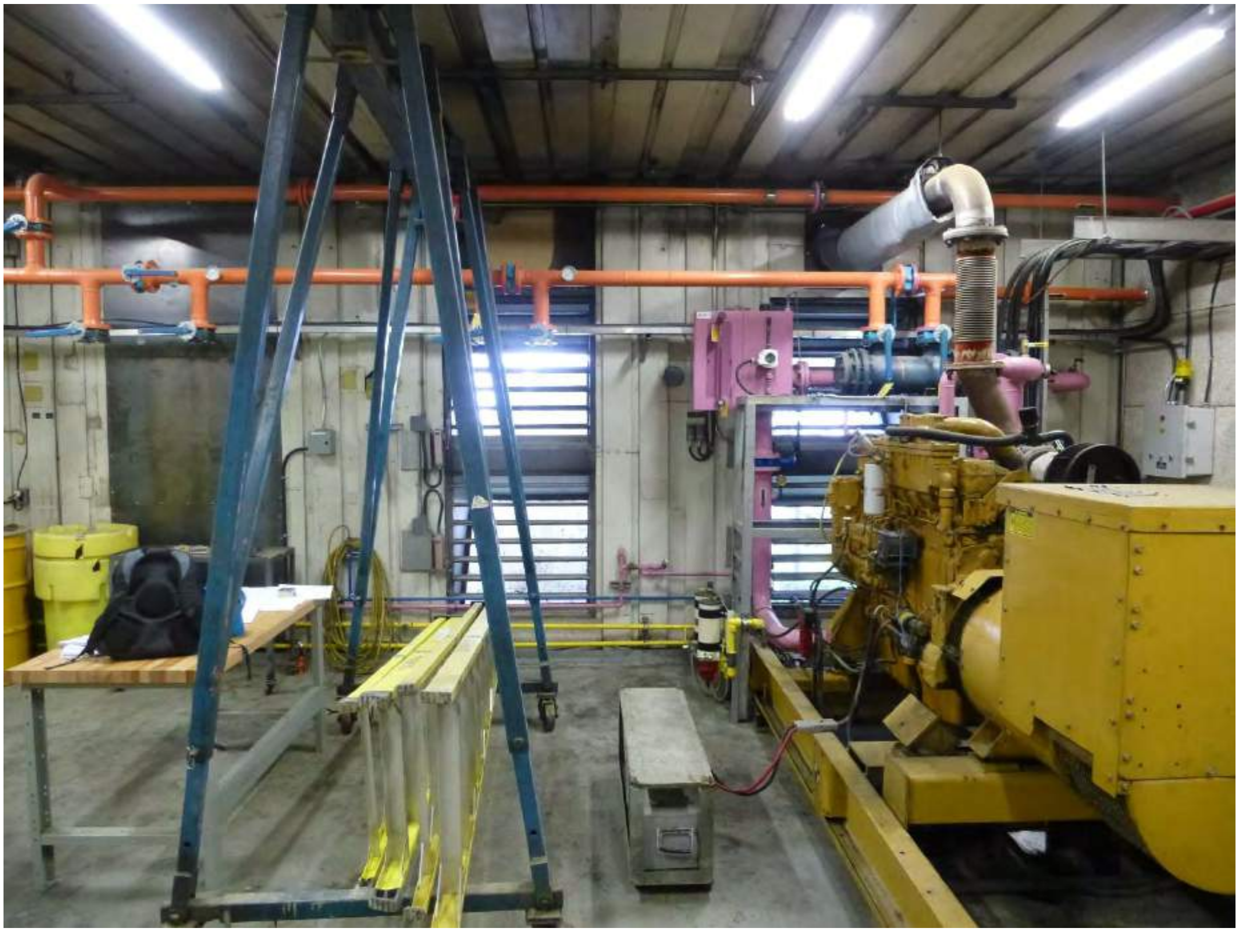


***Figure 4**: Lansdowne House Unit A Generator.*

Material Investment Narrative

Gull Bay (KZA) DGS Upgrade

INVESTMENT SUMMARY

Main Driver:	**Capacity Constraints**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	0	0	0	0	0

Summary:

This investment involves the upgrade of the Gull Bay B generation unit with a new 725 kW unit which, along with two other units, supply electricity to over 123 customers in the growing community of Gull Bay. The community served by Gull Bay DGS will not be grid-connected by the Watay Transmission project and will therefore continue to rely on diesel-generated electricity. Due to the continued growth in this community, the peak station load at Gull Bay DGS reached 340 kW in 2021 or 93% of the connection restriction limit and 85% of the station prime rating limit. The existing generation unit B will be decommissioned and either placed into storage to be used as a spare unit or be auctioned off. The investment also replaces the step-up transformer. This investment is 100% recoverable through a funding agreement with Gull Bay First Nation and ISC.

The investment is expected to increase the Gull Bay DGS prime rating from 430 kW to 650 kW and raise the connection limit to 553 kW, allowing for peak load growth in the community well into the future, and ensuring the continued delivery of safe and reliable prime-power generation in the community of Gull Bay.

A. General Information on the Project/Program

1. Overview

The Gull Bay (KZA) diesel generation station (DGS) was originally built in 2009 and consists of 3 diesel generators: Gull Bay A, B and C. The DGS currently supplies electricity to 123 customers in the growing community of Gull Bay. This community will not be grid-connected when the Watay Transmission Project comes online, and as a result, these units are critical and are required to supply electricity to the community for years to come. The engine size, speed, vintage, condition and current and forecast engine hours are summarized in Table 1. Images of the Gull Bay site location and Gull Bay DGS are included in Attachment 1.

Table 1: *Engine Condition of Generators in The Gull Bay DGS*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition[2]	Engine Hours[3]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Gull Bay A	400	1,800	2009	Good	22,071	24,804	27,945	31,945	35,945	39,945
Gull Bay B	180	1,800	2020	Very Good	4,824	8,766	1,500	4,500	7,500	10,500
Gull Bay C	250	1,800	2011	Good	20,146	21,072	22,102	23,131	24,161	25,190

[1] In-service year normally corresponds to the year the unit was installed.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The engine condition is current as of February 2022.
[3] Engine-hours shown are current as of February 8, 2022.

The electrical demand in remote communities is continually increasing due to new infrastructure, new housing, and population growth. The DGS capacity must be larger than the peak demand to ensure Remotes can continue to provide reliable power. When peak demand reaches 85% of the DGS capacity, new electrical connections are restricted in the community to ensure Remotes can continue to provide reliable service to existing customers. Connection restrictions can lead to a shortage of housing and delayed connection of new community infrastructure (arenas, schools, etc.).

The community of Gull Bay recently undertook a few big community projects, including building a new water treatment plant, and have plans to build a school as well, increasing demand on the system. The peak station load at Gull Bay reached 340 kW in 2021, nearing its connection restriction limit of 366 kW, or 85% of the station prime rating (430 kW), which is based on the two smallest units in service. With recent growth and infrastructural development in the community, the need for reliable and unrestricted access to electricity is increasing.

To continue accommodating these community driven projects and ensure that the community is not negatively affected by insufficient capacity, Remotes is proposing to increase the capacity of the Gull Bay DGS by replacing the existing 180 kW Gull Bay B generator (as seen in Figure 3 of Attachment 1), with a new 725 kW generator set. The station step-up transformers will also be replaced. The replacement of the generator and step up transformer will increase the station prime rating from 430 kW to 650 kW and raise the connection restriction limit to 553 kW. This will allow for peak load growth in the community past the forecasting horizon of 2034. Gull Bay Unit B was selected for the upgrade as it is the smallest generator at the station. Since this unit is still in good condition and has low engine-hours, this unit will either be reused, kept as a spare or be auctioned off. Remotes will assess the potential uses of Unit B further once it is taken out of service.

The project design was initiated in July 2019 as part of Phase 1 of this project, and Phase 2, corresponding to the purchase of long lead materials was initiated in January 2021. Phase 3 of this project, which is planned to be completed in August 2023, includes the purchase of remaining materials and the construction/installation of building support systems, generator, transformers, yard expansion and the building foundation to accommodate the larger unit. The overall Gull Bay DGS Upgrade project is expected to cost $5.6M. This work is 100% recoverable through a funding agreement with Gull Bay First Nation and Indigenous Services Canada (ISC). Once the funding is in place, a vendor will be selected by Gull Bay First Nation with recommendations from Remotes to construct the new building. The building contractor will have a contract directly with Gull Bay and be paid directly by the First Nation. If there is a requirement for any changes to the scope, design and cost, these are discussed with the Gull Bay First Nation community and approved with the ISC with all Remotes' costs fully recoverable.

By implementing this project, the customers in Gull Bay will be able to make new connections to the distribution system in order to add more housing and supply new critical infrastructure projects within the community. This upgrade is consistent with ensuring customers' expectations for unrestricted connection to the distribution system.

2. Timing

i. Start Date: July 2019

ii. In-Service Date: August 2023

iii. Key factors that may affect timing: The timing of this project is dependent on ISC approval for the capital dollars required. If there is a delay in any materials, especially long-lead items from the manufacturer, this could delay the project so Remotes must be diligent in its upfront planning activities. In addition, Remotes has to ensure it has the correct resources available to complete the project and that resources can be safely transported to site. Any changes to scope and design could delay the project as any changes to funding have to be approved by the ISC. Any delays in receiving the necessary environmental regulatory approvals (air and noise emissions) can also affect the project timing.

3. Historical and Forecast Capital Expenditures

Table 2: *Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	300	0	1,300	1,300	2,700	0	0	0	0	5,600
Contributions	0	(300)	0	(1,300)	(1,300)	(2,700)	0	0	0	0	(5,600)
Capital (Net)	0	0	0	0	0	0	0	0	0	0	0

This is a multi-year project with in-service date of August 2023. Remotes serves customers of First Nation reserves under funding agreements with ISC. Under these agreements, ISC pays for capital related load growth. As a result, the capital costs associated with this work is 100% recoverable.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The planned total cost of this investment is $5.6M and includes a building expansion, the replacement of a generator set and station transformers, along with the associated construction costs. In order to compare the cost to other station upgrade investments, cost per kW can be considered. The new 1,800 rpm generator unit has a capacity of 825 kW, rendering the cost per kW at $6,787.

A DGS upgrade of similar scope was completed at Marten Falls in 2021, where a new 1,200 rpm generator unit with capacity of 1,045 kW was installed at the total cost of $5.8M, and per-kW cost of $5,550. The observed cost differences can mostly be attributed to the difference in generator rpm, increased material, transportation and labour costs, and inflation.

6. Investment Priority

This is a high priority investment. Without this investment, the Gull Bay First Nation community will not be able to make new connections to the distribution system, which will restrict their continued growth and development.

7. Alternatives Analysis

Remotes has considered the following options:

- <u>Option 1: Do Nothing</u> – Doing nothing will limit the future growth and development of the community. The community had several big projects in the recent years such as establishment of a water treatment plant, and now plans to build a school. Additional capacity is required to accommodate these customer driven projects and growth. As a result, doing nothing is not a viable option.

- <u>Option 2: Demand Management</u> – This is not a long-term solution. This is a growing and developing community, so increased electrical capacity is required to satisfy that growth.

- <u>Option 3: Incorporating Alternative Sources</u> – The cost of incorporating alternative generation sources such as renewables is very high, and they do not provide the necessary level of reliability. Renewable generation sources are also intermittent and are unable to provide baseload energy on their own. As a result, this is not a viable option.

- <u>Option 4: Increase the Gull Bay DGS Capacity (Selected Option)</u> – This option includes replacing the existing 180 kW Gull Bay B unit with a new 725 kW unit and replacing the station step-up transformers. This option will increase the station prime rating from 430 kW to 650 kW and allow for peak load growth in the community past the forecasting horizon of 2034. This is the preferred option for the community of Gull Bay.

8. Innovative Nature of the Project

There is nothing inherently innovative to Remotes about this project.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 3: *Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	By replacing the old generator with a new one that incorporates the latest technology, both diesel generation efficiency and carbon emission intensity would be positively affected. In addition, operating a newer more reliable unit will reduce the probability of unplanned failures. This means less callouts for unexpected maintenance response, allowing staff to be redeployed to other critical maintenance and capital project tasks.
Customer Value	The DGS upgrade will allow the community to connect new housing and new infrastructure projects (e.g., school, arena, community centre, etc.) to grow and develop their community over the forecast period and beyond.
Reliability	Since new infrastructure development projects are being undertaken in the community, this upgrade will eliminate connection restrictions until at least 2034 while maintaining levels of reliability. Without the increased capacity, community demand will approach and eventually surpass the capacity of the DGS. This would negatively impact reliability because the generators and auxiliaries would be running at/or beyond their design limit, which often causes failures. Newer units are also less prone to unplanned failures and thus have improved reliability and generator availability.
Safety	By implementing this project, the DGS will not be operating near its rated capacity and therefore will have less chance of failures that could impose safety and fire risks. All upgrades to generator PLCs and related infrastructure will also meet the latest cyber-security standards.

2. Investment Need

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load has surpassed 85% of the station rating. The forecast peak load for Gull Bay is shown below in kW.

Table 4: *Gull Bay Forecast Peak Load*

Community	Connection Limit (kW)	Forecast Peak Load (kW)					
		2022	2023	2024	2025	2026	2027
Gull Bay	366	348	355	362	370	377	385

The existing DGS capacity is not sufficient to accommodate forecast growth in the community. Without an upgrade, connection restrictions will be required to protect the electrical supply for existing customers. This project will allow the Gull Bay First Nation community to build and connect adequate housing and other infrastructure to meet growing demands of the community. Sufficient generating capacity allows Remotes to continue providing reliable service and not negatively impact SAIDI and SAIFI as would happen if community demand surpassed DGS capacity.

i. Main Driver: Capacity Constraints – Based on current projections and known upcoming developments, community growth and development will be stifled without this project. This DGS capacity upgrade is required to accommodate the growth and development in the community over the forecast period and beyond.

ii. Secondary Drivers*:* Reliability – Reliability of the power supply to existing customers will be affected without a DGS upgrade. By upgrading the station capacity, the reliability can be maintained at current levels for customers.

iii. Information Used to Justify the Investment: The need for this investment was identified through annual peak load forecasts, which is a key input into Remotes' planning and asset management process, as well as through ISC and community consultations. New infrastructure projects in the community will require increased capacity and reliability, and peak load forecasts have shown that community demand will surpass the DGS connection limit by 2025. Additional information on Remotes' asset management process and peak load forecasts can be found in Section 5.3 of the DSP.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: Remotes' policy is to notify a community when their peak load reaches 75% of the DGS rating so they can prepare a funding request with ISC as they are responsible for capital upgrades to the DGS. It typically takes three years for a community to grow from 75% to 85% of the DGS rating, when connection restrictions are implemented. The 75% notification is meant to allow enough time to get the funding in place and complete the upgrade before connection restrictions are required to protect the electrical supply for existing customers. Even with connection restrictions, the demand from existing customers will continue to grow and will strain the DGS, affecting reliability. Upgrades ensure that stations are not loaded so highly that reliability is compromised. All necessary approvals for air and noise emissions will also be met for this project.

ii. *Cost-Benefit Analysis:* Alternatives will not allow Remotes to maintain the costs and electrical reliability for customers. A capacity upgrade is the only alternative that will allow Remotes to maintain the electrical reliability for existing customers while also accommodating new growth and development within the community.

iii. *Historical Investments & Outcomes Observed:* Remotes has undertaken similar DGS capacity upgrades in recent years. These investments have allowed continued growth and development within the communities which benefited residents. They also allowed Remotes to ensure dependable generation and reliability for existing customers.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. Conservation and Demand Management

i. *Project Deferrals:* CDM is not a long-term solution. Increased electrical capacity is required to accommodate the growing and developing community.

ii. *Cost-Benefit Analysis:* A capacity upgrade is the only alternative that will allow Remotes to maintain the electrical reliability for customers.

iii. *Use of Advanced Technology*: There is no advanced technology planned for this upgrade. Remotes is part of the Off-Grid Utilities Association (OGUA), a group of utilities that service off grid communities. Through that association and other interests, Remotes is not aware of any proven technology that can replace diesel generators for prime power at this time.

5. Innovation

There is nothing innovative in this project for Remotes.

ATTACHMENT 1: GULL BAY SERVICE AREA AND DGS IMAGES

Images of the Gull Bay DGS site location, Gull Bay DGS and Gull Bay B Unit generator are shown in Figure 1, Figure 2 and Figure 3, respectively.

Figure 1: *Gull Bay DGS Site Location*

Figure 2: *Gull Bay DGS.*

Figure 3: *Gull Bay B Generator.*

3D design upgrade models for the Gull Bay DGS are included in Figure 4 and Figure 5. The area highlighted in grey is the existing infrastructure, and the area highlighted in bright colours will be new additions to the station.

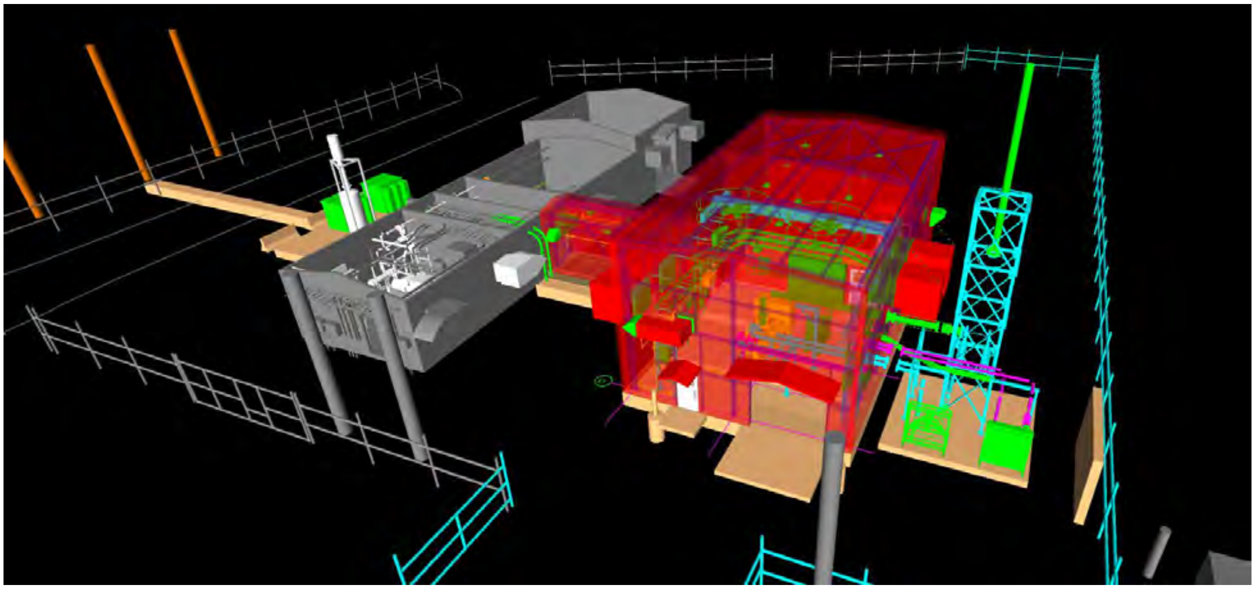


Figure 4: *3D Design Upgrade Model for the Gull Bay DGS*

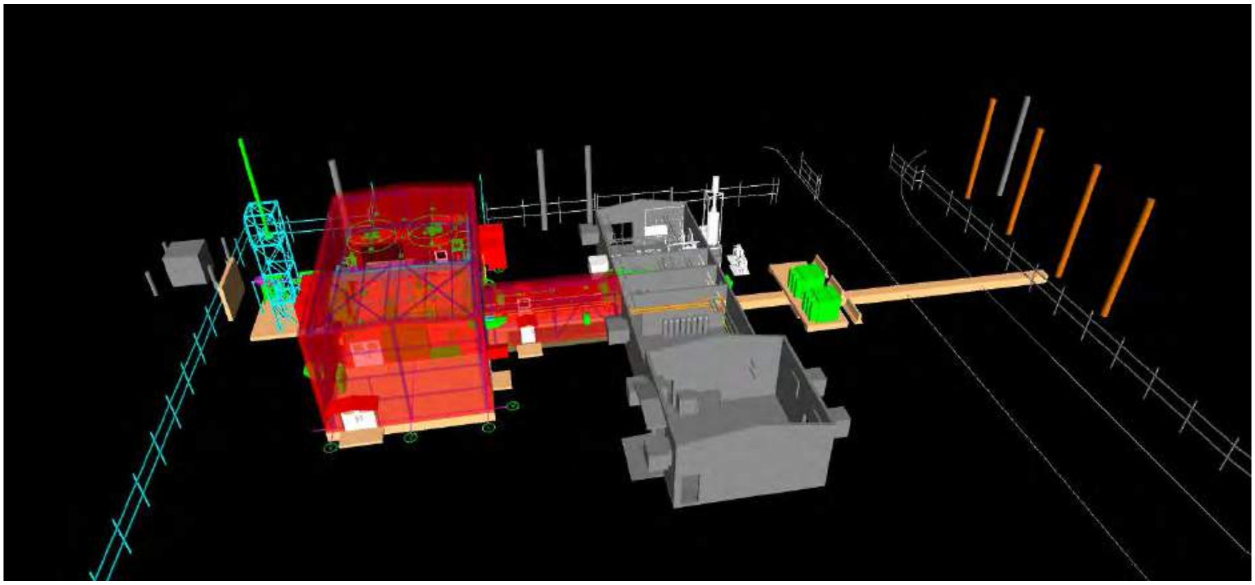


Figure 5: *3D Design Upgrade Model for the Gull Bay DGS.*

Material Investment Narrative

Beaverhall Facility Expansion/Relocation

INVESTMENT SUMMARY

Main Driver:	**Non-System Physical Plant**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness, Public Policy Responsiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	1,476	0	0	0	0

Summary:

This investment involves the expansion or relocation of Remotes' main offices which are currently fully utilized and at capacity, and which will no longer adequately serve the needs of its customers. Remotes will also be required to increase current staff levels by up to four people in 2023 to account for the additional work associated with the six IPA communities being added to Remotes' customer base, as well as ensuring uninterrupted routine work. The investment also increases the available yard space for equipment and materials and create a dedicated shop space.

The investment is expected to provide the necessary space required to provide a workplace where employees can work safely in all areas of the facility and will allow Remotes to increase staffing resources to ensure that its customers receive quality customer service and reliable power. Working conditions are expected to improve as overcrowding is eliminated, while the increased yard space will allow for equipment and materials to be stored properly providing a safe area to work efficiently. Additionally, the increased shop space is expected to eliminate the need for trade staff to perform work in high traffic areas.

A. General Information on the Project/Program

1. Overview

Remotes' main office located at 680 Beaverhall Place no longer adequately serves the needs of the company. An expansion or relocation is required to provide an effective long-term solution as the business has grown and evolved over time. Increases in yard, shop and office space are required to meet the needs of Remotes staff and to support the continued operation of Remotes systems.

Remotes currently has 57 permanent staff and 12+ seasonal workers for a total of approximately 70 staff overall. Remotes will be required to increase staffing resources by up to four people for 2023 to account for the increase in work associated with the additional six Independent Power Authority (IPA) communities being added to Remotes' customer base in 2023 and 2024. Remotes will require additional staff to manage the additional workload to ensure that customers receive quality customer service and reliable power. In addition, there is a need to increase the yard and shop space to be able to support these additional communities.

Remotes has made investments into the building footprint in 2011 and 2012, installed a temporary office trailer in 2012 which is still in use, and fully utilizes all available office, yard and shop space, but a more appropriate long-term solution is required. This need is further strengthened by the additional staffing and space requirements associated with the Watay Project and addition of the six new IPA communities to Remotes' customer base.

Remotes has been exploring various options over the last two years to provide a solution to the limited office, shop and yard space. Remotes has enlisted an architectural firm to review the existing property to provide options of expanding the facility, within the limited remaining lot size. Remotes has also hired a real estate firm to provide a market analysis of the existing facility as well as other potential facilities available in the local area.

At the time of preparing this document, the preferred option has not been confirmed, but Remotes will continue to evaluate the options in 2022 and proceed with the optimal solution in 2023.

2. Timing

i. *Start Date*: August 2022

ii. *In-Service Date:* December 2023

iii. *Key factors that may affect timing:* The main factor is the availability of properties for sale and/or resources to complete expansion of the existing facilities. The return to office protocol and a proposed Hybrid work model related to the pandemic will also impact the timing of this need.

3. Historical and Forecast Capital Expenditures

Table 1: *Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($'000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	490	1,476	0	0	0	0	1,966
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	490	1,476	0	0	0	0	1,966

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Remotes has undertaken a few smaller upgrades and investments in its facilities in 2011 and 2012, but nothing in the last five years. Some of the older investments made are noted below for reference.

- 2011 – Mezzanine renovation to provide a new meeting room and an additional six desk spaces. ($300K)
- 2012 – New 30 x 40 civil shop built to provide a safe workspace for the civil crew. ($145K)
- 2012 – Temporary Office Trailer including desk space for four, plus storage. ($35K)

6. Investment Priority

Remotes currently utilizes all the available space of the existing facility and requires more space to meet the needs of the current staff and planned growth. In order to meet the demands of the business and customers Remotes need to provide a comfortable, safe and efficient space for employees to work. The existing facilities are no longer adequate and require upgrading or expansion to fulfill the business needs. This project is a high priority for Remotes to continue to operate safely and efficiently.

7. Alternatives Analysis

Remotes has been exploring various alternatives over the last two years to provide a solution due to the lack of office, shop and yard space. Remotes has enlisted an architectural firm to review the existing property to provide options of expanding the facility, within the limited remaining lot size. Remotes has also hired a real estate firm to provide a market analysis of the existing facility as well as other potential facilities available in the local area.

The project options being considered are:

- <u>Option 1: Purchase Vacant Land for Yard Storage</u> – This option includes the purchase of vacant land in close proximity to the existing facility for yard storage. This option would only provide a solution to Remotes' storage requirements, and as a result, Remotes would still need to investigate solutions to the office and shop space requirements. This option has been estimated at $500K.

- Option 2: Expand Office & Purchase Vacant Land for Yard Storage – This option includes expanding the existing facility and the purchase of nearby vacant land for yard storage. This option would provide the additional office space and yard space but there would be no additional shop space. This option is estimated at $1.5-$2M.
- Option 3: Purchase an Existing Local Facility – This option includes the purchase of a local facility that will be available in 2023 and selling the existing facility. This option is estimated at approximately $1.8-$2M. This cost does not include any potential gains from selling the current facility.
- Option 4: Custom Build on Vacant Land – Another option explored was to purchase property and build a new custom facility to meet the needs of Remotes. This option will not be considered going forward as the cost to complete this option was estimated to exceed $12M.

As previously noted above, the preferred option has not been confirmed, but Remotes will continue to evaluate the options in 2022 and proceed with the optimal solution in 2023. For planning purposes, Remotes has estimated that the project will cost approximately $2M.

8. Innovative Nature of the Project

While no final solution has been determined, Remotes is considering facilities and options with green energy solutions and reduced environmental impacts in mind.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 2: *Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The existing facility does not meet the requirements of the business which results in many inefficiencies while staff are completing their routine work. The increase in space will meet the needs of the business and allow the staff to work more efficiently and safely.
Customer Value	This investment would allow Remotes to have the space and facilities needed to continue meeting customer needs as it incorporates 6 additional IPA communities.
Reliability	This is not applicable.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	This investment would provide the necessary space required to provide a workplace where employees can work safely in all areas of the facility. The increased yard space would allow equipment and material to be stored properly providing a safe area to work efficiently. The increased office space would provide better working conditions and eliminate the overcrowding in meeting rooms and desk areas. A dedicated shop space would provide a safe work zone that eliminates the need for trade staff to perform work in high traffic areas.

2. Investment Need

i. *Main Driver*: Non-system physical plant - The existing facility (office, shop and yard) no longer meet the requirements of the business. This project is needed to address the essential needs to support the business and customers.

ii. *Secondary Drivers:* Business Operations Efficiency - Through upgrading to fit for purpose facilities, Remotes staff will be able to carry out its operations as efficiently and safely as possible, delivering to customer expectations.

iii. *Information Used to Justify the Investment*: The current facility was analyzed and compared to the actual requirement of the business. Table 3 illustrates the results of the analysis.

***Table 3**: Summary of Current Facility Analysis*

Summary of Facility Area	Current	Minimum Requirement	Ideal Requirement
Main building square footage	18,238	22,818	24,079
Trades shop / workable space square footage	5,700	6,150	6,825
Indoor cold storage	10,686	13,917	14,118
Outdoor storage (yard space for material)	20,000	24,000	26,000
Number of non-secured parking spaces	29	40	42
Number of parking spaces for equipment	20	20	20
Number of parking spaces (office staff)	30	40	42
Number of desk spaces (office staff)	50	55	55
Number of shop desk (trades staff)	20	22	26

Remotes has also engaged an architectural firm and real estate firm to design its requirements, source potential available sites and supply cost estimates. Alternatives being considered are listed in part 7 of section A and are supported by the attached documents.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: The driver for this project is to meet the space requirements of Remotes' business. This will improve the safety and efficiency of the Remotes operating facility directly impacting employee health, safety and working conditions. The project will also improve employee morale. It is prudent and good utility practice to ensure appropriate office, workshop and yard storage space to facilitate the customer needs now and in the future.

ii. *Cost-Benefit Analysis:* This will be further investigated in 2022 to determine the best cost-benefit solution for Remotes.

iii. *Historical Investments & Outcomes Observed:* Remotes has undertaken a number of smaller upgrades and investments in its facilities in 2011 and 2012, which have enabled Remotes to carry out its job efficiently and safely. No new investments have been made in the last five years.

iv. *Substantially Exceeding Materiality Threshold:* Alternatives being considered by Remotes are listed above in part 7 of section A, and are further supported by the attached documents:

- Attachment 1: Drawings Issued for Costing – This document was prepared by the architectural firm Form Studio Architects Inc. and includes several architectural drawing options issued for costing purposes.
- Attachment 2: Cost Estimates – This document was prepared by Postma Quantity Surveying and includes Class D Cost estimates for the architectural drawing options 1b & 2 outlined in Attachment 1.
- Attachment 3: Property Appraisal of 680 Beaverhall Place – This document was prepared by Andrew, Thompson & Associates (ATA) Ltd. Real Estate Advisors and includes the investigation and analysis of the property as of July 28, 2021.
- Attachment 4: Consulting Report of Alternate Building / Site Opportunities – This document was prepared by ATA Real Estate Advisors and includes the resulting site / building availability search for new facilities in the Thunder Bay Market.

4. Conservation and Demand Management

CDM is not applicable for facility expansions or relocations.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis*: This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

As noted above, Remotes is considering facilities with green energy options as potential options for this project.

ATTACHMENT 1:

DRAWINGS ISSUED FOR CONSTRUCTION

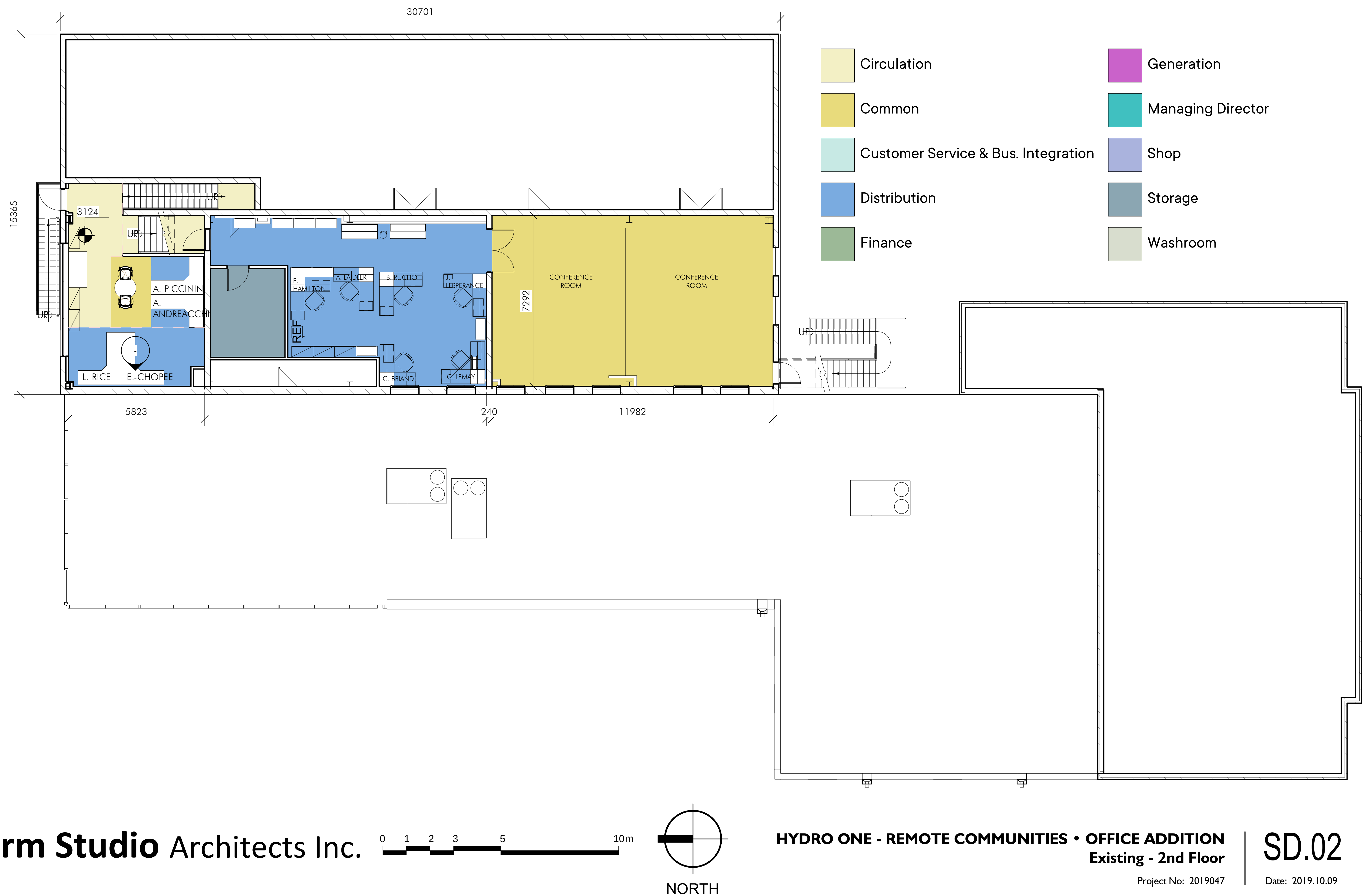
Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Existing - Main Floor

Project No: 2019047

SD.01

Date: 2019.10.09



Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Existing - 2nd Floor

Project No: 2019047

SD.02

Date: 2019.10.09

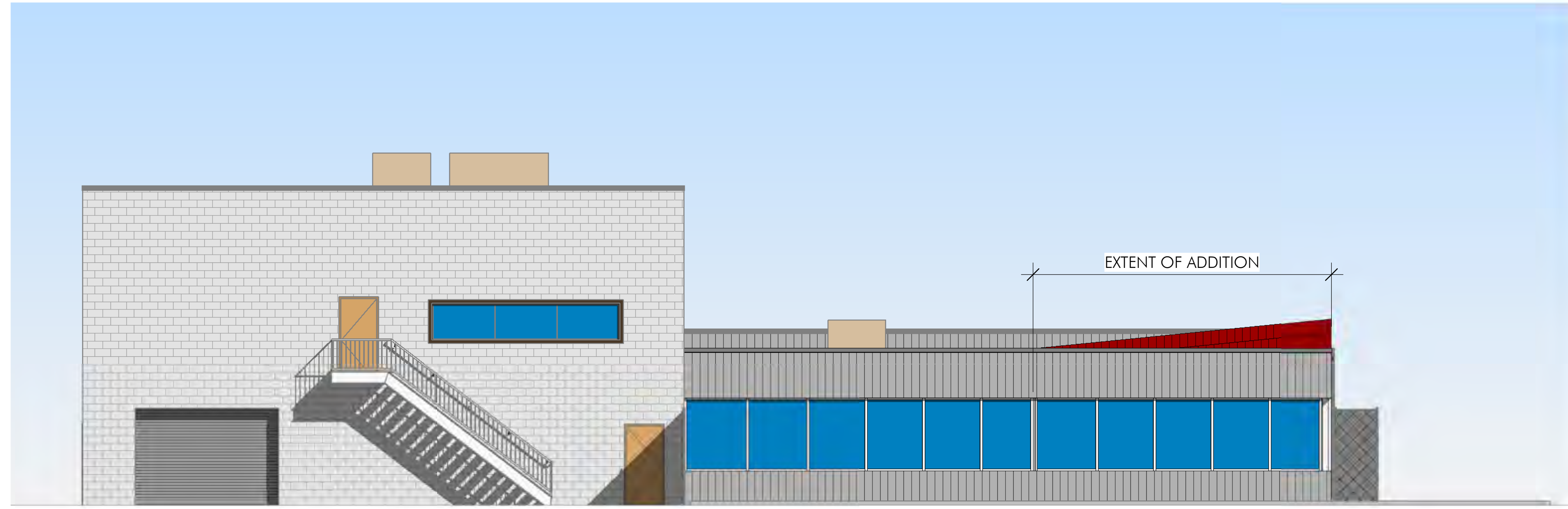
Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 1b - Main Floor

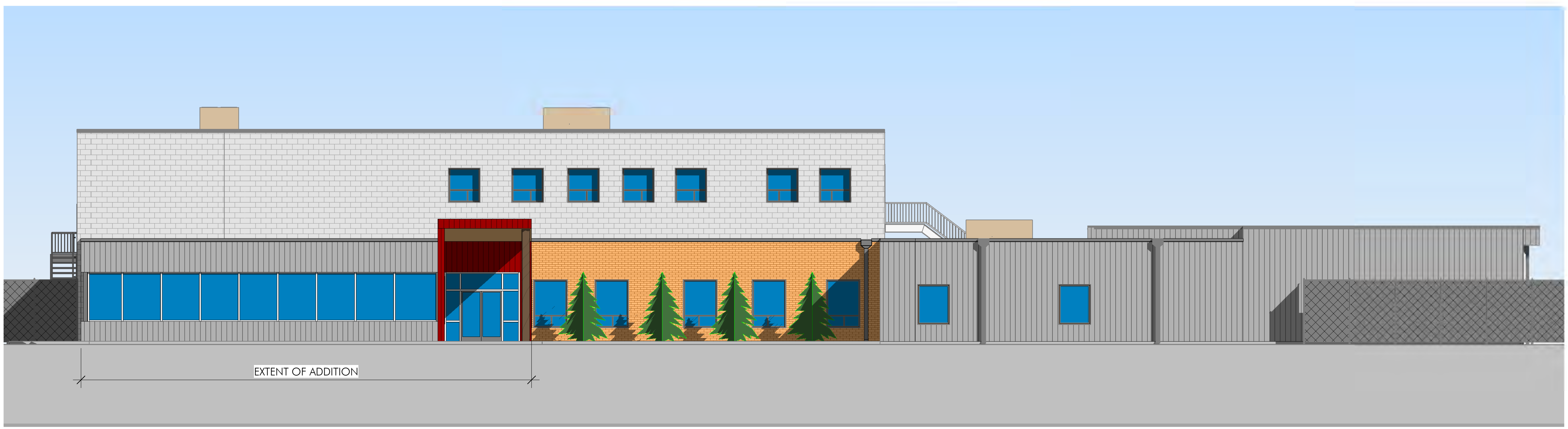
Project No: 2019047

SD.06

Date: 2019.10.09



1 SD.07 Elevation North - 1b
scale = 1 : 150

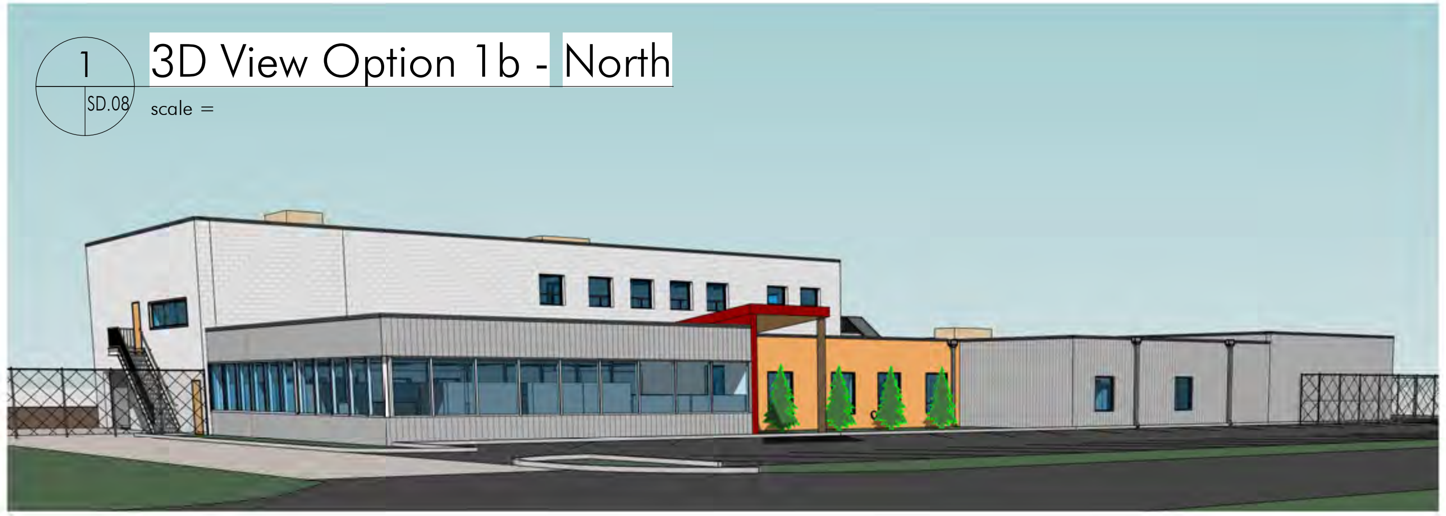


2 SD.07 Elevation West - 1b
scale = 1 : 150

Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 1b - Elevations
Project No: 2019047

SD.07
Date: 2019.10.09



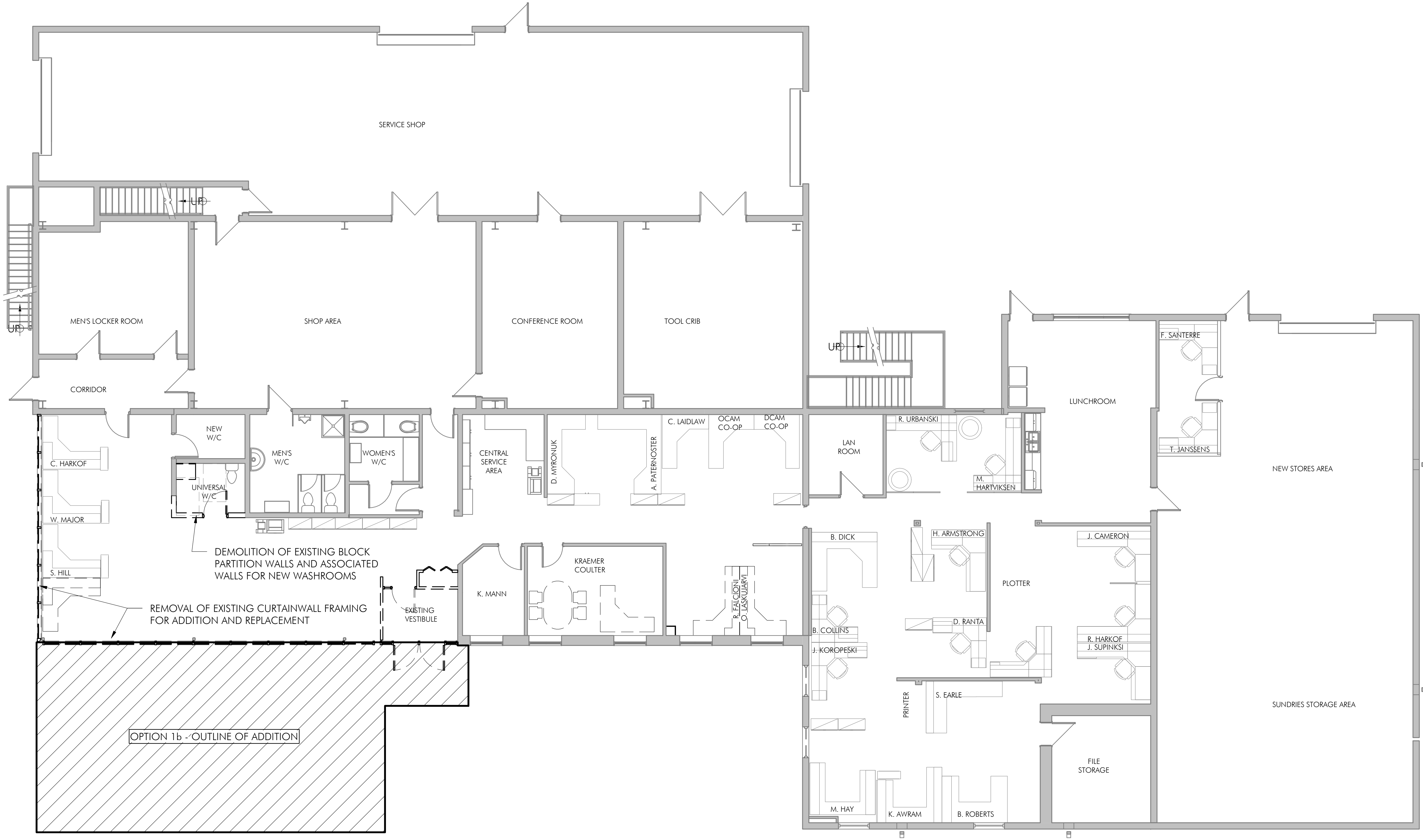
Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 1b - 3d Views

Project No: 2019047

SD.08

Date: 2019.10.09



Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 1b - Demolition
Project No: 2019047

SD.15
Date: 2019.10.09

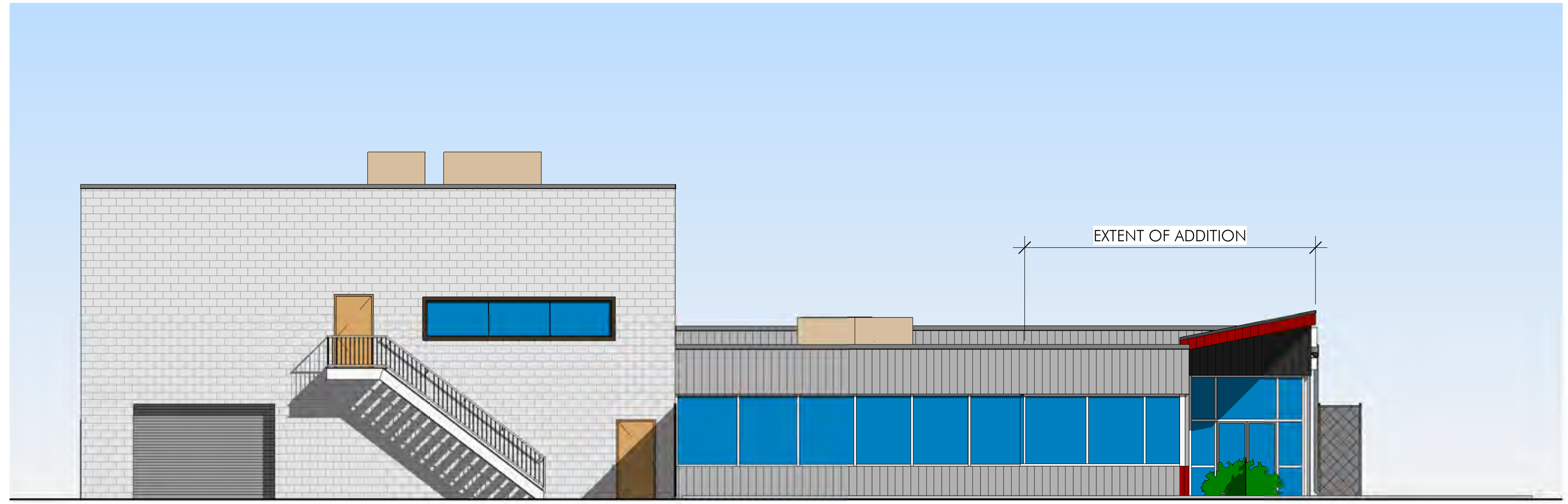
Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 2 - Main Floor

Project No: 2019047

SD.09

Date: 2019.10.09



1 SD.10 Elevation North - 2
scale = 1 : 150

2 SD.10 Elevation West - 2
scale = 1 : 150

Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 2 - Elevations
Project No: 2019047

SD.10
Date: 2019.10.09

1 SD.11 3D View Option 2 - North
scale =

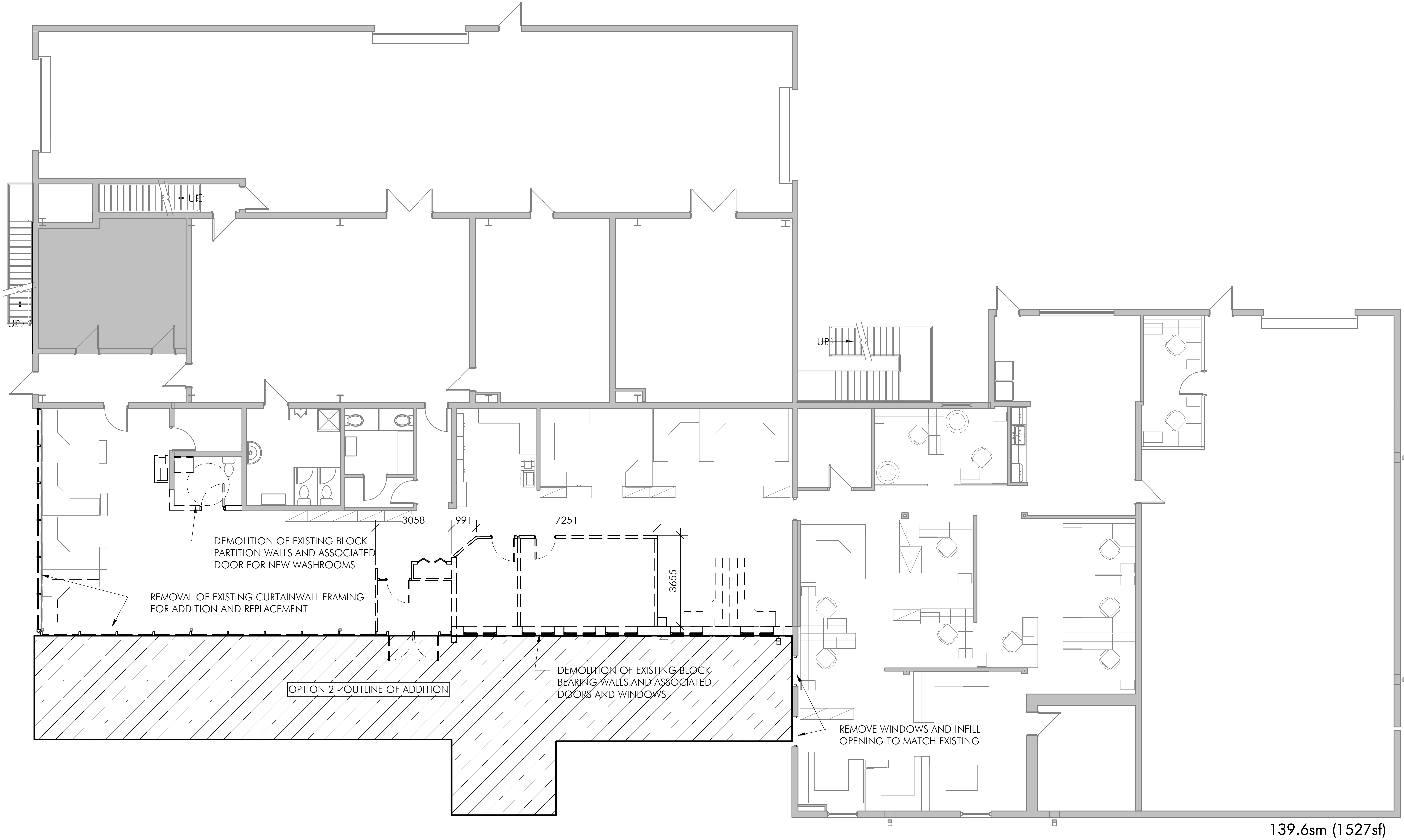
3 SD.11 3D View Option 2 - South
scale =

2 SD.11 3D View Option 2 - North Aerial
scale =

Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 2 - 3d Views
Project No: 2019047

SD.11
Date: 2019.10.09



Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 2 - Demolition Plan

Project No: 2019047

SD.16

Date: 2019.10.09

ATTACHMENT 2:

COST ESTIMATES

305-93 Lombard Ave.
Winnipeg, MB R3B 3B1
Phone: (204) 415-3700
Email: pqs@shaw.ca
www.postmaquantitysurveying.ca

October 31, 2019

Form Studio Architecture
131 Court Street North
Thunder Bay, Ont.
P7A 4V1

Attention: Matthew Mills

Re: **Hydro One Remote Communities Office Renovations and Addition**
Thunder Bay, Ont.
Class D Estimates

We are pleased to attach our class D estimate for the above noted project and do hereby certify the following values as noted below which include a 15% design contingency.

- Option 1b $712,610.00
- Option 2 $935,900.00

The estimate excludes, contingency allowances, hazardous abatement, HST, furniture and any consulting fees. The pricing reflects probable construction costs obtainable in the location of the project as of the date of this estimate and is a determination of fair market value for the construction of this project and should not be taken as a prediction of low bid.

This pricing assumes competitive bidding for every portion of the construction work including all subcontractors as well as the general contractor and assumes a minimum of four (4) general bidders. If fewer bids are received, the bid results can be expected to be higher.

It is recognized, however, that Postma Quantity Surveying does not have control over the cost of labour, material or equipment, over a contractor's methods of determining bid prices, or over competitive bidding, market or negotiation conditions.

Accordingly, Postma Quantity Surveying cannot and does not warrant or represent that bids or negotiated prices will not vary from this or any subsequent estimate of construction cost or evaluation prepared or agreed to by Postma Quantity Surveying. It is generally acknowledged that a Class D estimate is within the range of plus or minus twenty (20%) percent.

We hope this meets to your satisfaction. If you have any questions, please do not hesitate to call.

POSTMA QUANTITY SURVEYING LTD.

Wesley Postma

Wes Postma, PQS, CET, GSC
President

Hydro One Remote Communities, Thunder Bay, Ont option 1 b

Class D Estimate 10/31/2019

Postma Quanitity Surveying Ltd.

	Descripton of Work Building	Unit	Quantity Building	Unit Price	Total Building
1	**General Conditions**				
2	Supervision, site administration - 2 phases	month	7	$9,000.00	$63,000
3	Indirect Site Costs - 2 phases	month	7	$3,600.00	$25,200
4	Overhead & Fee GC	%	7.00	$580,000	$40,600
5	Bonds & Insurance, permits	thous.	620	$25.00	$15,500
6	Cash Allowances - testing & inspections	item	$ 1.00	$0.00	none shown
7				Subtotal	$144,300
8	**Site work & demolition**				
9	Strip asphalt & man door conc pad	sm	110	$20.00	$2,200
10	Excavate to underside of gravel base at SOG	m3	38	$40.00	$1,520
11	Excavate foundation wall and footing	m3	71	$21.00	$1,491
12	Backfill walls with gravel	m3	82	$75.00	$6,150
13	New concrete mandoor pad	m2	17	$170.00	$2,890
14	Weeping tile at footings	m	32	$50.00	$1,600
15	New conc curb	m	30	$60.00	$1,800
16	Site sod repairs	sm	10	$50.00	$500
17	Asphalt repair	m2	25	$42.00	$1,050
18	Remove vestibule coat closet walls/doors	ea	1	$50.00	$50
19	Remove part masonry wall w\r	sm	7	$50.00	$350
20	Remove exist'g w/r fr/dr	ea	1	$60.00	$60
21	Remove alum/glass vestibule	sm	12	$30.00	$360
22	Haul demo off site	loads	1	$450.00	$450
23	Remove alum fr/drs-	pr	1	$250.00	$250
24	Remove curtainwall framing for add & replacement	sm	60	$53.00	$3,180
25				Subtotal	$23,901
26	**Structural Elements**				
27	Continous Concrete footings 32 LM	m3	5	$925.00	$4,625
28	Concrete walls on footing	m3	13	$1,150.00	$14,950
29	Rebar	kg	6500	$2.40	$15,600
30	St columns 9 thus 3.6 h 150 sq.HSS	kg	1,275	$11.00	$14,025
31	C 200x38 roof beam	kg	1,212	$11.00	$13,332
32	OWSJ 3@7500,12@4.4 and steel deck	m2	110	$107.00	$11,770
33	C or girt to support curtainwall sill	lm	22	$32.00	$704
34				Subtotal	$75,006
35	**Rough Carpentry, Architectural Woodwork, Misc metal**				
36	Rough carpentry- misc blocking,roof & window	item	1	$4,200.00	$4,200
37	Window sills	m	22	$75.00	$1,650
38	Cabinets upper incl mail slots	m	0	$500.00	none shown
39	Cabinets lower	m	0	$1,000.00	none shown
40	Allow modular furniture	station	12	$4,000.00	with FF&E
41				Subtotal	$5,850
42	**Insulation, AVB, Roofing, siding, stone**				
43	Dampproofing foundation wall	m2	48	$8.00	$384
44	102 mm rigid at grade beam	m2	48	$68.00	$3,264
45	Roof single ply membr. R-40	m2	110	$210.00	$23,100
46	Fascia at canopy/roof/trim	lm	64	$40.00	$2,560
47	vert.mt clad,Z bar,R-30 rigid,blueskin	m2	51	$160.00	$8,160
48	canopy wd log post, timber roof framing w mt brackets	lm	28	$68.00	$1,904

Hydro One Remote Communities, Thunder Bay, Ont option 1 b

Class D Estimate 10/31/2019

Postma Quanitity Surveying Ltd.

	Descripton of Work Building	Unit	Quantity Building	Unit Price	Total Building
49	wood soffit	m2	17	$65.00	$1,105
50	Canopy roof w fascia-non insul -red	m2	28	$110.00	$3,080
51	Insul canopy walls red ?	m2	35	$160.00	$5,600
52	75 rigid frost protection backfill	m2	40	$43.00	$1,720
53	Downspouts with splash pads	no	3	$175.00	$525
54	Firestopping	item	1	$400.00	$400
55				Subtotal	$51,802
56	**Doors & windows**				
57	Quiet rm fr/dr/hard'w	no	1	$1,000.00	$1,000
58	Universal w/r fr/dr/hard'w	no	1	$900.00	$900
59	curtainwall or storefront 22 x1.8 h	sm	40	$750.00	$30,000
60	Auto operator	no	2	$2,500.00	$5,000
61	Aluminum entrance with sidelights/transom 10 sm	no	1	$11,000.00	$11,000
62	Interior standard vest entry alum fr/drs	pr	1	$3,500.00	$3,500
63	Exterior windows- Alum 2@ 1 x1.5	m2	3	$850.00	$2,550
64				Subtotal	$53,950
65	**Drywall, Acoustic Ceilings, Flooring, Painting**				
66	int-16mm drywall/SS walls-quiet,w/r ,vestibule insul	m2	98	$28.00	$2,744
67	16mm /SS to ext wall 29 x 3.6 less glass	m2	52	$60.00	$3,120
68	Cut & patch drywall for m/e, misc-rw/r ceiling	m2	10	$11.00	$110
69	Drywall ceilings incl vestibule	m2	110	$45.00	$4,950
70	Drywall bulkhead at new/replace window framing	lm	23	$75.00	$1,725
71	Acoustic tile ceil in addition, minor patch in exist'g	sm	102	$55.00	$5,610
72	New flooring - carpet tile	m2	102	$50.00	$5,100
73	Porcelain tile w/r and vest	m2	32	$180.00	$5,760
74	Vinyl base	m	51	$8.00	$408
75	Painting	m2	110	$35.00	$3,850
76				Subtotal	$33,377
77	**Specialties**				
78	Washroom Accessories	item	1	$1,500.00	$1,500
79	Window blinds -Allow	item	1	$3,000.00	$3,000
80				Subtotal	$4,500
81	**Mechanical**				
82	Mechanical as per attached worksheets	item	1	$129,370.00	$129,370
83				Subtotal	$129,370
84	**Electrical**				
85	Electrical as per worksheet attached	item	1	$97,605.00	$97,605
86				Subtotal	$97,605
87	**Subtotal**				$619,661
88	Escalation			0.00%	$0
89	**SUBTOTAL**				$619,661
90	Design contingency			15.00%	$92,949
91	**TOTAL**				**$712,610**

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 1b		1	m2		
C1 Mechanical						
C11 Plumbing & Drainage						
1	Fixture		1	m2	3,300.00	3,300
	Water closet		1	ea.	800.00	800
	Water closet Barrier free		1	ea.	900.00	900
	Lavatory		1	ea.	750.00	750
	Lavatory Barrier free		1	ea.	850.00	850
2	Domestic Water		1	m2	6,500.00	6,500
	Connect to existing		1	no	500.00	500
	Domestic water pipe		1	sum	3,500.00	3,500
	Thermal pipe insulation		1	sum	1,500.00	1,500
	Fixture rough in		4	ea.	250.00	1,000
3	Sanitary Waste and Vents		1	m2	8,150.00	8,150
	Connect to existing		1	no	500.00	500
	Sanitary drain - below grade		1	sum	2,000.00	2,000
	Sanitary vents - above grade		1	sum	2,000.00	2,000
	Floor drain		2	no	200.00	400
	Fixture rough in		4	ea.	250.00	1,000
	Concrete cut and patch		1	sum	1,500.00	1,500
	Excavation and backfill		1	sum	750.00	750
4	Natural gas		1	m2	1,700.00	1,700
	Disconnect and reconnect RTU		2	no	850.00	1,700
5	Demolition		1	m2	500.00	500
	Remove fixture c/w drains and water pipe		2	no	250.00	500
	C11 Plumbing & Drainage	Total : $	1	m2	20,150.00	20,150
C12 Fire Protection						
1	Fire extinguisher		1	m2	400.00	400
	Wall hung extinguisher		2	no	200.00	400
	C12 Fire Protection	Total : $	1	m2	400.00	400

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 1b		1	m2		
C13 HVAC						
1	Air handling units and fans		1	m2	25,350.00	25,350
	Roof top unit - gas heating - package cooling 7.5 ton		2	ea.	12,500.00	25,000
	Washroom exhaust		1	no	350.00	350
2	Air distribution ductwork & devices		1	m2	50,970.00	50,970
	Galvanized ductwork		1200	kg	20.00	24,000
	Thermal insulation		250	sm	30.00	7,500
	Acoustic insulation		100	sm	45.00	4,500
	VAV box		1	ea.	1,000.00	1,000
	VAV box c/w re-heat coil		5	ea.	1,500.00	7,500
	Supply diffuser		16	ea.	225.00	3,600
	Return grill		12	ea.	185.00	2,220
	Exhaust grill		2	ea.	175.00	350
	Wall box		1	ea.	300.00	300
3	Balancing & commissioning		1	m2	2,750.00	2,750
	Air balancing		1	sum	2,000.00	2,000
	TAB		1	sum	750.00	750
4	Demolition		1	m2	5,000.00	5,000
	Remove existing Roof top unit		2	no	2,500.00	5,000
	C13 HVAC	Total : $	1	m2	84,070.00	84,070
C14 Controls						
1	Controls		1	m2	24,750.00	24,750
	Roof top unit		2	no	1,500.00	3,000
	VAV box		6	no	1,000.00	6,000
	Exhaust fan timer		1	no	750.00	750
	Electric re-heat coil		5	no	1,000.00	5,000
	BAS control		1	sum	10,000.00	10,000
	C14 Controls	Total : $	1	m2	24,750.00	24,750
	Mechanical	Total : $	1	m2	129,370.00	129,370

	Building Area - Option 1b		1	m2		
C2 Electrical						
C21 Service and Distribution			1	m2	5,750.00	5,750
1	New panel from existing		1	no	2,500.00	2,500
2	Feeders					
	- panel feeder		100	ft	25.00	2,500
3	Testing		1	sum	500.00	500
4	Grounding		1	sum	250.00	250
C21 Service and Distribution		Total	1	m2	5,750.00	5,750
C22 Lighting, devices and heating						
1	Light fixtures		1	m2	38,150.00	38,150
	Fixture type 2 by 4		30	no	500.00	15,000
	Fixture type pot		6	no	250.00	1,500
	Fixture type exterior wall		4	no	450.00	1,800
	Emergency double head		10	no	200.00	2,000
	Exit sign		4	no	450.00	1,800
	Single Pole switch / motion		2	no	125.00	250
	Occupancy sensor		8	no	350.00	2,800
	Lighting branch wiring		1	no	12,500.00	12,500
	Lighting demolition - remove fixture		10	no	50.00	500
2	Power outlets, devices and connections		1	m2	22,555.00	22,555
	Duplex receptacle 15A		40	no	125.00	5,000
	Duplex receptacle 20A		2	no	130.00	260
	Duplex receptacle USB		2	no	135.00	270
	Duplex receptacle GFI		2	no	140.00	280
	Duplex receptacle GFI WP		1	no	145.00	145
	Barrier free door operator		2	no	550.00	1,100
	Hand dryer		2	no	750.00	1,500
	Branch wiring		1	sum	12,500.00	12,500
	Power demolition		1	sum	1,500.00	1,500

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 1b		1	m2		
3	Mechanical equipment connection		1	m2	7,250.00	7,250
	Roof top unit		2	no	1,500.00	3,000
	Exhaust fan		1	no	150.00	150
	VAV		6	no	100.00	600
	Branch wiring		1	sum	3,500.00	3,500
4	Electric Heating		2	m2	2,250.00	4,500
	Force Flow		2	no	850.00	1,700
	Baseboard heater		2	no	350.00	700
	Connection		4	no	150.00	600
	Branch wiring		1	sum	1,500.00	1,500
	C22 Lighting, devices & heating	Total	1	m2	72,455.00	72,455

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 1b		1	m2		
C23 Systems & Ancillaries						
1	Fire alarm		1	m2	9,600.00	9,600
	Connect to existing fire alarm panel		1	no	1,500.00	1,500
	Horn/strobe		3	no	550.00	1,650
	Detector - smoke / thermal		5	no	350.00	1,750
	Pull station		1	no	200.00	200
	Wiring		1	sum	3,500.00	3,500
	Verification		1	sum	1,000.00	1,000
2	Communication		1	m2	6,500.00	6,500
	New terminal strip and rack		1	sum	1,000.00	1,000
	Data outlet		20	no	100.00	2,000
	Conduit and wiring		1	sum	3,500.00	3,500
3	Security		1	m2	3,300.00	3,300
	Connect to existing system		1	sum	500.00	500
	Motion detector		4	no	450.00	1,800
	Conduit and wiring		1	sum	1,000.00	1,000
	C23 Systems & Ancillaries		1	m2	19,400.00	19,400
	Electrical	Total : $	1	m2	97,605.00	97,605

Hydro One Remote Communities, Thunder Bay, Ont. option 2

Class D Estimate 10/31/2019

Postma Quanitity Surveying Ltd.

	Descripton of Work Building	Unit	Quantity Building	Unit Price	Total Building
1	**General Conditions**				
2	Supervision, site administration	month	7	$9,000.00	$63,000
3	Indirect Site Costs	month	7	$3,600.00	$25,200
4	Overhead & Fee GC	%	7.00	$760,585	$53,241
5	Bonds & Insurance, permits	thous.	807	$25.00	$20,175
6	Cash Allowances - testing & inspections	item	$ 1.00	$0.00	none shown
7				Subtotal	$161,616
8	**Site work & demolition**				
9	Strip asphalt & man door conc pad	sm	134	$20.00	$1,650
10	Excavate to underside of gravel base at SOG	m3	50	$40.00	$2,000
11	Excavate foundation wall and footing	m3	92	$21.00	$1,932
12	Backfill walls with gravel	m3	107	$75.00	$8,025
13	New concrete mandoor pad	m2	6	$170.00	$1,020
14	Weeping tile at footings	m	46	$50.00	$2,300
15	New conc curb	m	44	$60.00	$2,640
16	Site sod repairs	sm	10	$50.00	$500
17	Asphalt repair	m2	60	$42.00	$2,520
18	Remove vestibule coat closet walls/doors	ea	1	$50.00	$50
19	Remove part masonry wall w\r	sm	7	$50.00	$350
20	Strip w/r walls,flooring	sm	18	$12.00	$216
21	Remove dw partitions 25 LM	sm	90	$15.00	$1,350
22	Remove exist'g fr/drs	ea	4	$60.00	$240
23	Remove alum/glass vestibule w doors	sm	12	$45.00	$540
24	Remove alum windows- in masonry wall	ea	8	$80.00	$640
25	Shore 9 LM roof bm,demo masonry wall	sm	34	$84.00	$2,856
26	Remove curtainwall framing for add & replacement	sm	114	$40.00	$4,560
27	Hoarding for wall and window removal	sm	150	$30.00	$4,500
28	haul masonry rubble	load	1	$450.00	$450
29	load/haul windows,dw,etc incl binage	loads	4	$650.00	$2,600
30				Subtotal	$40,939
31	**Structural Elements**				
32	Continous Concrete footings 32 LM	m3	7	$925.00	$6,475
33	Concrete walls on footing	m3	17	$1,150.00	$19,550
34	Rebar	kg	8400	$2.40	$20,160
35	canopy roof fram'g- WF 250x38x23 lm,C150x27x20 lm	kg	1414	$11.00	$15,554
36	St columns 13 thus 3.6 h 150 sq.HSS	kg	1,842	$11.00	$20,262
37	C 200x38 roof beam 41 LM	kg	1,558	$11.00	$17,138
38	OWSJ 3@7500,17@4.4 and steel deck	m2	134	$107.00	$14,338
39	canopy steel deck	sm	26	$30.00	$780
40	C or girt to support curtainwall sill	lm	31	$32.00	$992
41	Masonry infill removed windows	ea	2	$800.00	$1,600
42				Subtotal	$116,849
43	**Rough Carpentry, Architectural Woodwork, Misc metal**				
44	Rough carpentry- misc blocking,roof & window	item	1	$4,200.00	$4,200
45	Window sills	m	40	$75.00	$3,000
46	Allow modular furniture	station	9	$4,000.00	with FF&E
47				Subtotal	$7,200
48	**Insulation, AVB, Roofing, siding, stone**				
49	Dampproofing foundation wall	m2	68	$8.00	$544
50	102 mm rigid at grade beam	m2	68	$68.00	$4,624
51	single ply membr. R-40, incl 26 SM canopy	m2	160	$210.00	$33,600
52	Fascia at canopy/roof/trim	lm	64	$40.00	$2,560

Hydro One Remote Communities, Thunder Bay, Ont. option 2

Class D Estimate 10/31/2019

Postma Quanitity Surveying Ltd.

	Descripton of Work Building	Unit	Quantity Building	Unit Price	Total Building
53	Vert.mt clad,Z bar,R-30 rigid,blueskin	m2	123	$160.00	$19,680
54	Canopy- red soffit 15 SM,fascia 15 LM	m2	30	$110.00	$3,300
55	Soffit or trim top of continous windows/vestibule	lm	50	$32.00	$1,600
56	75 rigid frost protection backfill	m2	51	$43.00	$2,193
57				Subtotal	$68,101
58	**Doors & windows**				
59	frame/door w sidelite,glazing,hard'w	no	3	$1,600.00	$4,800
60	interior PS borrowed lite frame/glazing 2 ea 2100x1500	sm	6	$240.00	$1,512
61	Universal w/r fr/dr/hard'w	no	1	$900.00	$900
62	curtainwall or storefront 33 x1.8 h	sm	60	$750.00	$45,000
63	Auto operator	no	2	$2,500.00	$5,000
64	Ext Curtainwall 3 sided w pr drs 10.4 LMx 3 M h	sm	31	$1,000.00	$31,000
65	Interior vest entry alum fr/drs, sidelites/transom 10 SM	pr	1	$7,500.00	$7,500
66	Employee room fr/dr/hard'w	ea	1	$900.00	$900
67	closet door/frame 600 mm w shelf	ea	1	$550.00	$550
68				Subtotal	$97,162
69	**Drywall, Acoustic Ceilings, Flooring, Painting**				
70	int-16mm drywall/SS walls-quiet,w/r ,vestibule insul	m2	124	$28.00	$3,472
71	16mm /SS DW to ext wall	m2	123	$60.00	$7,380
72	Cut & patch drywall for m/e, misc-rw/r ceiling	m2	6	$40.00	$240
73	Drywall ceilings - vestibule	m2	13	$45.00	$585
74	Drywall bulkhead at new/replace window framing	lm	37	$65.00	$2,405
75	New - carpet tile,addition 121, & renov 94 SM	m2	215	$50.00	$10,750
76	Acoustic ceilings - 134 SMaddition & 81 sm patch	m2	215	$55.00	$11,825
77	Porcelain tile w/r and vest	m2	31	$180.00	$5,580
78	Vinyl base	m	144	$8.00	$1,152
79	Painting addition,renov	m2	215	$35.00	$7,525
80				Subtotal	$50,914
81	**Specialties**				
82	Washroom Accessories	item	1	$1,500.00	$1,500
83	Window blinds -Allow	item	1	$3,000.00	$3,000
84				Subtotal	$4,500
85	**Mechanical**				
86	Mechanical as per attached worksheets	item	1	$150,160.00	$150,160
87				Subtotal	$150,160
88	**Electrical**				
89	Electrical as per worksheet attached	item	1	$116,385.00	$116,385
90				Subtotal	$116,385
91	**Subtotal**				$813,826
92	Escalation			0.00%	$0
93	**SUBTOTAL**				$813,826
94	Design contingency			15.00%	$122,074
95	**TOTAL**				**$935,900**

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 2		1	m2		
C1 Mechanical						
C11 Plumbing & Drainage						
1	Fixture		1	m2	3,300.00	3,300
	Water closet		1	ea.	800.00	800
	Water closet Barrier free		1	ea.	900.00	900
	Lavatory		1	ea.	750.00	750
	Lavatory Barrier free		1	ea.	850.00	850
2	Domestic Water		1	m2	6,500.00	6,500
	Connect to existing		1	no	500.00	500
	Domestic water pipe		1	sum	3,500.00	3,500
	Thermal pipe insulation		1	sum	1,500.00	1,500
	Fixture rough in		4	ea.	250.00	1,000
3	Sanitary Waste and Vents		1	m2	8,150.00	8,150
	Connect to existing		1	no	500.00	500
	Sanitary drain - below grade		1	sum	2,000.00	2,000
	Sanitary vents - above grade		1	sum	2,000.00	2,000
	Floor drain		2	no	200.00	400
	Fixture rough in		4	ea.	250.00	1,000
	Concrete cut and patch		1	sum	1,500.00	1,500
	Excavation and backfill		1	sum	750.00	750
4	Natural gas		1	m2	1,700.00	1,700
	Disconnect and reconnect RTU		2	no	850.00	1,700
5	Demolition		1	m2	500.00	500
	Remove fixture c/w drains and water pipe		2	no	250.00	500
	C11 Plumbing & Drainage	Total : $	1	m2	20,150.00	20,150
C12 Fire Protection						
1	Fire extinguisher		1	m2	400.00	400
	Wall hung extinguisher		2	no	200.00	400
	C12 Fire Protection	Total : $	1	m2	400.00	400

C13 HVAC

1	Air handling units and fans		1	m2	25,350.00	25,350
	Roof top unit - gas heating - package cooling 7.5 ton		2	ea.	12,500.00	25,000
	Washroom exhaust		1	no	350.00	350
2	Air distribution ductwork & devices		1	m2	67,260.00	67,260
	Galvanized ductwork		1600	kg	20.00	32,000
	Thermal insulation		300	sm	30.00	9,000
	Acoustic insulation		150	sm	45.00	6,750
	VAV box		3	ea.	1,000.00	3,000
	VAV box c/w re-heat coil		5	ea.	1,500.00	7,500
	Supply diffuser		24	ea.	225.00	5,400
	Return grill		16	ea.	185.00	2,960
	Exhaust grill		2	ea.	175.00	350
	Wall box		1	ea.	300.00	300
3	Balancing & commissioning		1	m2	3,250.00	3,250
	Air balancing		1	sum	2,500.00	2,500
	TAB		1	sum	750.00	750
4	Demolition		1	m2	5,000.00	5,000
	Remove existing Roof top unit		2	no	2,500.00	5,000
	C13 HVAC	Total : $	1	m2	100,860.00	100,860

C14 Controls

1	Controls		1	m2	28,750.00	28,750
	Roof top unit		2	no	1,500.00	3,000
	VAV box		8	no	1,000.00	8,000
	Exhaust fan timer		1	no	750.00	750
	Electric re-heat coil		5	no	1,000.00	5,000
	BAS control		1	sum	12,000.00	12,000
	C14 Controls	Total : $	1	m2	28,750.00	28,750
	Mechanical	Total : $	1	m2	150,160.00	150,160

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 2		1	m2		
C2 Electrical						
C21 Service and Distribution			1	m2	5,750.00	5,750
1	New panel from existing		1	no	2,500.00	2,500
2	Feeders					
	- panel feeder		100	ft	25.00	2,500
3	Testing		1	sum	500.00	500
4	Grounding		1	sum	250.00	250
C21 Service and Distribution		Total	1	m2	5,750.00	5,750
C22 Lighting, devices and heating						
1	Light fixtures		1	m2	47,950.00	47,950
	Fixture type 2 by 4		40	no	500.00	20,000
	Fixture type pot		6	no	250.00	1,500
	Fixture type exterior wall		5	no	450.00	2,250
	Emergency double head		12	no	200.00	2,400
	Exit sign		5	no	450.00	2,250
	Single Pole switch / motion		2	no	125.00	250
	Occupancy sensor		10	no	350.00	3,500
	Lighting branch wiring		1	no	15,000.00	15,000
	Lighting demolition - remove fixture		16	no	50.00	800
2	Power outlets, devices and connections		1	m2	26,935.00	26,935
	Duplex receptacle 15A		50	no	125.00	6,250
	Duplex receptacle 20A		3	no	130.00	390
	Duplex receptacle USB		2	no	135.00	270
	Duplex receptacle GFI		2	no	140.00	280
	Duplex receptacle GFI WP		1	no	145.00	145
	Barrier free door operator		2	no	550.00	1,100
	Hand dryer		2	no	750.00	1,500
	Branch wiring		1	sum	15,000.00	15,000
	Power demolition		1	sum	2,000.00	2,000

3	Mechanical equipment connection		1	m2	7,450.00	7,450
	Roof top unit		2	no	1,500.00	3,000
	Exhaust fan		1	no	150.00	150
	VAV		8	no	100.00	800
	Branch wiring		1	sum	3,500.00	3,500
4	Electric Heating		2	m2	2,250.00	4,500
	Force Flow		2	no	850.00	1,700
	Baseboard heater		2	no	350.00	700
	Connection		4	no	150.00	600
	Branch wiring		1	sum	1,500.00	1,500
	C22 Lighting, devices & heating	Total	1	m2	86,835.00	86,835
C23 Systems & Ancillaries						
1	Fire alarm		1	m2	11,500.00	11,500
	Connect to existing fire alarm panel		1	no	1,500.00	1,500
	Horn/strobe		4	no	550.00	2,200
	Detector - smoke / thermal		6	no	350.00	2,100
	Pull station		1	no	200.00	200
	Wiring		1	sum	4,500.00	4,500
	Verification		1	sum	1,000.00	1,000
2	Communication		1	m2	9,000.00	9,000
	New terminal strip and rack		1	sum	1,000.00	1,000
	Data outlet		30	no	100.00	3,000
	Conduit and wiring		1	sum	5,000.00	5,000
3	Security		1	m2	3,300.00	3,300
	Connect to existing system		1	sum	500.00	500
	Motion detector		4	no	450.00	1,800
	Conduit and wiring		1	sum	1,000.00	1,000
	C23 Systems & Ancillaries		1	m2	23,800.00	23,800
	Electrical	Total : $	1	m2	116,385.00	116,385

ATTACHMENT 3:

PROPERTY APPRAISAL OF 680 BEAVERHALL PLACE

ATA Real Estate Advisors

Property Appraisal Of

680 Beaverhall Place
Thunder Bay

Prepared For

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

ANDREW, THOMPSON & ASSOCIATES LTD.

ANDREW, THOMPSON & ASSOCIATES LTD.

177 Dunlop Street West
Barrie, ON L4N 1B4
PHONE 705-721-1596 FAX 705-721-5183
WEB www.andrew-thompson.on.ca

ATA Real Estate Advisors

August 17, 2021

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

Attention: Mr. Keith Barr

Re: 680 Beaverhall Place, Thunder Bay

Dear Mr. Barr:

At your request, we provide this report describing our investigation and analysis of the above referenced property, as of July 28, 2021. We understand the purpose of this report is to estimate market value. The intended use is to assist with an asset review. This report is to be relied upon by the client only unless otherwise stated. The property rights appraised in this report are the fee simple ownership, assuming the title to be free and clear of all encumbrances, unless otherwise stated. This report should be read in its entirety prior to making a decision to rely upon the report.

As a result of our investigation it is our professional opinion that the subject property in its Highest and Best Use as a continued industrial use has a current market value of $2,300,000,

TWO MILLION THREE HUNDRED THOUSAND DOLLARS

Any Extraordinary Assumptions, Hypothetical Conditions and/or Extraordinary Limiting Conditions are noted in Section 6.0.

As of the date of this report Canada and the Global Community is experiencing unprecedented measures undertaken by various levels of government to curtail health related impacts of the Covid-19 Pandemic. The duration of this event is not known. While there is potential for impacts with respect to micro and macro-economic sectors, as well as upon various real estate markets, it is not possible to predict such impact at present, or the impact of current and future government countermeasures. Accordingly, this point-in-time valuation assumes the continuation of current market conditions, and that current longer-term market conditions remain unchanged. Given the market uncertainties of the Covid-19 pandemic, a force majeure event, we reserve the right to revise the value estimation set out in this report for a fee, with an update appraisal report under a separate appraisal engagement, incorporating market information available at that time. Values contained in this appraisal are based on market conditions as at the time of this report. This appraisal does not provide a prediction of future values. In the event of market instability and/or disruption, values may change rapidly and such potential future events have NOT been considered in this report. As this appraisal does not and cannot consider any changes to the property appraised or market conditions after the effective date, readers are cautioned in relying on the appraisal after the effective date noted herein.

This current short narrative report is provided in a format that is consistent with the Terms of Reference and in accordance with the Canadian Uniform Standards of Professional Appraisal

Practice (C-USPAP) adopted by the Appraisal Institute of Canada.

We trust the information provided meets with your approval and thank you for considering our firm.

Respectfully Submitted,
ANDREW, THOMPSON AND ASSOCIATES LTD.

DRAFT

Peter Spivey, B.Sc, AACI, P.App

TABLE OF CONTENTS

1.0 Introduction

This report addresses the current market valuation of the Hydro One Remote Communities facility situated at 680 Beaverhall Place. The property is located in the Beaverhall Industrial Area, a concentration of industrial development located to the immediate east of the Thunder Bay International Airport.

The subject property represents a 2.82 acre parcel improved with a 15,570 sq.ft. office / service industrial building, a 4,065 sq.ft, cold storage warehouse, a 1,200 sq.ft. workshop and a number of small storage buildings. The main office / service industrial building is comprised of approximately 8,790 sq.ft. of office space and 6,780 sq.ft. of service shop, storage and shop office area. The site is fully graded and includes a rear gravel storage yard and a front paved parking lot.

Figure 1 Source: City of Thunder Bay GIS

2.0 Photographs of the Subject Property

Front View of Subject Building

Rear View of Subject Service Garage Area (Main Building)

Rear View of Main Building

View of Warehouse Building

View of Front Paved Parking Lot

View of Rear Yard Area

View of Workshop

Sheds / Yard Area

Neighbourhood View Looking South along Beaverhall Place

Neighbourhood View Looking North along Beaverhall Place

3.0 Executive Summary

Intended Users	Hydro One Remote Communities Inc.
Address	680 Beaverhall Place, Thunder Bay
Legal Description	Lot 13, Plan W796, (Neebing), City of Thunder Bay
PIN #	620430045
Registered Owner	Ontario Hydro
Effective Date	July 28, 2021
Inspection Date	July 28, 2021

3.1 Property:

Lot Size	2.82 acres	
Building GFA	Office / Service Industrial Building	15,570 sq.ft.
	Cold Storage Warehouse	4,065 sq.ft,
	Workshop	1,200 sq.ft.
	Total	20,835 sq.ft.
Official Plan Designation	Light Industrial	
Zoning	IN2 - Medium Industrial Zone	
Present Use	General Industrial	
Highest and Best Use		
Land as if Vacant	Development as a permitted industrial use.	
Improved	Continued industrial use as developed.	

3.2 Valuation:

Purpose and Intended Use of the Appraisal	To estimate the market value to assist with an asset review.	
Value Estimates	Cost Approach	$2,509,000
	Direct Comparison Approach	$2,188,000 to $2,396,000
Final Estimate of Market Value	**$2,300,000**	

Any Extraordinary Assumptions, Hypothetical Conditions and/or Extraordinary Limiting Conditions are noted in Section 6.0.

4.0 Basis of the Appraisal

Client – The Client for this file is Hydro One Remote Communities Inc.. We received our instructions from Mr. Keith Barr.

The Intended User(s) - This report is intended for use only by Hydro One Remote Communities Inc.. Use of this report by others is not intended by the member, and any liability in this respect is strictly denied. Should an additional user wish to rely on this report, the member requires the client's instructions in writing and the additional user requires a separate release letter from the member and under all other circumstances no liability is extended to third party users.

Purpose of the report - The purpose of this appraisal is to estimate the market value of the subject property as of July 28, 2021.

Intended use of the report - The intended use of this appraisal is to assist Hydro One Remote Communities Inc. with an asset review.

We have not applied a Jurisdictional Exception in the preparation of this report.

5.0 Terms of Reference

At the request of Hydro One Remote Communities Inc., Andrew, Thompson & Associates Ltd. was instructed to:

1. Undertake a Narrative Appraisal Report in accordance with the "Standards" (Canadian Uniform Standards of Professional Appraisal Practice, CUSPAP) of the Appraisal Institute of Canada.
2. Provide an independent and objective opinion.

There were no specific Terms of Reference (TOR) provided.

6.0 Extraordinary Assumptions, Hypothetical Conditions and Limiting Conditions

6.1 Extraordinary Assumptions

An extraordinary assumption refers to an assumption, directly related to a specific assignment, which, if found to be false, could materially alter the opinions or conclusions.

- None

6.2 Hypothetical Conditions

A hypothetical condition is that which is contrary to what exists, but is supposed to exist for the purpose of analysis.

- None

6.3 Extraordinary Limiting Condition

An extraordinary condition is a necessary modification or exclusion of a Standard Rule which may diminish the reliability of the report.

- As of the date of this report Canada and the Global Community is experiencing unprecedented measures undertaken by various levels of government to curtail health related impacts of the Covid-19 Pandemic. The duration of this event is not known. While there is potential for impacts with respect to micro and macro-economic sectors, as well as upon various real estate markets, it is not possible to predict such impact at present, or the impact of current and future government countermeasures. Accordingly, this point-in-time valuation assumes the continuation of current market conditions, and that current longer-term market conditions remain unchanged. Given the market uncertainties of the Covid-19 pandemic, a force majeure event, we reserve the right to revise the value estimation set out in this report for a fee, with an update appraisal report under a separate appraisal engagement, incorporating market information available at that time. Values contained in this appraisal are based on market conditions as at the time of this report. This appraisal does not provide a prediction of future values. In the event of market instability and/or disruption, values may change rapidly and such potential future events have NOT been considered in this report. As this appraisal does not and cannot consider any changes to the property appraised or market conditions after the effective date, readers are cautioned in relying on the appraisal after the effective date noted herein.

- In this instance the Income Approach has not been utilized. Although sometimes suitable, it appears that larger standalone industrial facilities such as the subject in the local market are in most instances' owner occupied and are not typically acquired as income producing properties. As such we have not applied an Income Approach in this instance.

7.0 Scope of Work Undertaken

Each appraisal assignment is different. Depending on the size, type and use the complexity may vary and the significance and level of research may also vary. The level of investigation that is appropriate for each appraisal problem is that level of care that the reasonable member would apply. In some cases, based on the client's needs and the intended use the focus of the engagement may require greater detail or verification.

The specific tasks considered necessary to complete this assignment were as follows:

7.1 Property / Site Observation

We observed the subject property on July 28, 2021. We were accompanied by Mr. Keith Barr and Mike Hartviksen on that date. The enclosed pictures were taken on this date unless otherwise stated.

With respect to the buildings we typically observe all unlocked and available rooms. Attics are not inspected unless requested or there is an observed condition that warranted the request for access to view the attic. Basements are observed where available and passable, crawl spaces are not observed. Roof reports are requested from the client at the outset of the assignment. Roofs are not inspected by the appraiser, however, are observed as possible. We do not accept liability or responsibility to report the condition or remaining useful life of a roof covering unless this specifically forms part of the Terms of Reference. Photography taken is where deemed required, permitted or requested. Electrical, mechanical, electronic, plumbing infrastructure and operations are not inspected and are assumed to meet the required building / fire code and in good operating condition except where otherwise noted.

The site is observed to the extent deemed reasonable depending on the site size, varying characteristics etc. No subsurface or surface tests are completed by the appraiser and no responsibility for below grade or unseen features, equipment or improvements form part of the inspection.

7.2 Review:

The following items **were considered**:

- Development trends, economic and real estate market conditions in relation to the subject existing as of the effective date; reviewed and analyzed the sales history of the subject.
- The physical, functional and economic characteristics for the subject property.
- Municipal data from various sources including government publications, municipal economic development departments and real estate publications.
- **Title Search**: It is assumed that the subject property was not subject to any encumbrances (mortgages, liens, etc) that would have negatively impacted the market value of the subject property as of the effective date. We have completed a parcel register search of the subject and examined relevant documents if noted in the property information section of this report.
- **Land Use Controls**: Publications produced by the local and regional municipality have been relied upon for land use controls including:
    - Official Plan(s)
    - Zoning By-laws
- Determined Municipal services available to the subject property.
- Considered and analyzed the Highest and Best Use of the property.
- After assembling and analysing the data, a final estimate of value was made.

- The valuation methods applied in this report arise from those determined to best address the specific type of property addressed in this analysis.
- We confirm that we saw no indication of environmental or contamination concerns at the date of our inspection unless further noted under the site description section of this report.

7.3 Data Research:

We have conducted market research with regard to comparable sales, in the Municipality and surrounding areas. We further gathered sales data obtained from sources including:

- Local Real Estate Board(s)
- Realtrack
- Geowarehouse/MPAC
- Review of internal files.
- Discussions with real estate agents and other members.
- Comparable sales have been confirmed by inspection, title review and/or interview with a party or agent to the sale when deemed necessary.

7.4 Third Party Information:

The analysis set out in this report relied upon written and verbal information obtained from a variety of sources considered reliable. Unless otherwise stated we did not verify client-supplied information, which we believed to be correct. The mandate for the appraisal did not require a report prepared to the standard appropriate for court purposes or for arbitration.

- The time and cost to confirm third party information can exceed reasonable appraisal budgets and accordingly this report relies upon written and verbal information provided from primary and hearsay sources. Client supplied information is assumed correct and was verified where possible. Any party relying upon this report should confirm with the member the source of important information and assumptions underlying the conclusions in our report.

7.5 Excluded Item(s) of Review

The following technical investigations **were not completed**:

- An environmental review or study of the subject property, including a historical use analysis;
- A site survey;
- Setback measurements;
- Investigation into bearing qualities of the soils;
- Subsurface qualities of the soil; percolation or other soil qualities; or;
- An archaeological review.
- With respect to the building we did not complete technical investigations such as detailed inspections or engineering review of the structure, roof or mechanical systems; an environmental review; audit of financial statements or other legal agreements; an investigation with the local fire department, building inspector, health department or any other government regulatory agency except as described in this report.

8.0 Appraisal Framework

8.1 Rights Appraised

Fee Simple is defined as absolute ownership by any other interest or estate, subject only to the limitations imposed by government powers of taxation, expropriation, police power and escheat. Leased Fee interests occurs when the property is encumbered by a lease. The valuation herein is based on the fee simple interest and assumes a 100% undivided interest.

8.2 Report Format

This current short narrative report is provided with regard to the rules and regulations as outlined in the prevailing CUSPAP.

The Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) outlines the standard rules as it relates to the development and communication of a formal opinion of value and identifies the minimum content necessary to produce a credible report that is not misleading.

An appraisal is a formal opinion of value that is: a) prepared as a result of a retainer; b) intended for reliance by identified parties; and c) for which the member assumes responsibility. This type of report must incorporate the minimum content necessary to produce a credible report that will not be misleading. The types of appraisal reports include; Narrative - either concise/short narrative reports or comprehensive / detailed reports and Form Reports - a standardized format combining check-off boxes and narrative comments.

Current Value – refers to an effective date contemporaneous with the date of the report, at the time of inspection or at some other date within a reasonably short period from the date of inspection when market conditions have not or are not expected to have changed.

9.0 Definitions

9.1 Definition of Market Value

The most probable price which a property should bring in a competitive and open market as of the specific date under all conditions requisite to a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus.
Implicit in this definition is the consummation of a sale as of a specified date and the passing of title from seller to buyer under conditions whereby;

1. buyer and seller are typically motivated;
2. both parties are well informed or well advised, and acting in what they consider their best interests;
3. a reasonable time is allowed for exposure in the open market;
4. payment is made in terms of cash in Canadian Dollars or in terms of financial arrangements comparable thereto; and
5. the price represents the normal consideration for the property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.

9.2 Effective Date

The date at which the analyses, opinions and conclusions in an assignment may apply. The effective date may be different from the inspection date and/or the report date.

9.3 Jurisdictional Exception

An assignment condition that permits the member to disregard a part or parts of the Standards that are determined to be contrary to law or public policy in a given jurisdiction and only that part shall be void and of no force or effect in that jurisdiction.

9.4 Fee Simple Interest

The highest estate or absolute right in real property. This represents the highest rights and fewest limitations and is generally considered absolute ownership. However, this bundle of rights (the right to use, sell, lease, enter, give away, or to refrain from any of these rights in regard to property) is subject to various restrictions imposed by laws of governing bodies[1].

9.5 Member

A term used throughout CUSPAP referring to a designated member or candidate member.

9.6 Leased Fee Interest

When a property is encumbered by a lease its status changes and the rights of the owner are considered to be the leased fee, versus an unencumbered property which is referred to as fee simple interest.

9.7 Definition of Economic Rent

Economic rent is the reasonable rental expectancy of the property if it were available for lease as compared with similar space; as distinguished from contract rent.

---

1 *"Real Estate Encyclopaedia", copyright OREA March, 1997, page 389*

9.8 Intangible Property (Assets)

Non physical assets, including but not limited to franchises, trademarks, patents, copyrights, goodwill, equities, mineral rights, securities, and contracts, as distinguished from physical assets such as facilities and equipment.

9.9 Assemblage

The merging of adjacent properties into one common ownership or use.
Note: If applicable to the subject valuation and assemblage impacts the value, this will be addressed in the neighbourhood or valuation section.

9.10 Lease

A legal agreement which grants right to use, occupy, or control all or part of a property, to another party, for a stated period of time based on the terms and covenants of the lease including, among other things, the rental rate.

9.11 Occupant

The occupant is described as the person who has the right to occupy a unit or space (e.g. rental apartment, condominium unit, residential dwelling, office space).

9.12 Chattel

A tangible and moveable item that is not a fixture may be personal property and may be included with the realty.

9.13 Client

The client is the individual or organization for whom the member renders professional services. The client is typically the intended user of the assignment.

9.14 Confidential Information

Information, not otherwise publicly available, provided in trust that the recipient will not disclose to a third party.

In accordance with the Personal Information Protection Electronic Documents Act (PIPEDA), the Appraiser sought and received the written approval of the client, a copy of which is on file at the member's office, to take pictures of the exterior and interior of the building and the property. Information provided to the Appraiser has been held as confidential where instructed by the client. The Appraiser made every effort to avoid taking pictures of any personal information that would make the occupant identifiable, regardless of physical form or characteristics.

9.15 Intended User

The client and any other party, as identified by name, as a user of the professional services of the Member, based on communication between the Member and the client.

10.0 Property Information

10.1 Legal Description and Restrictions

Address	680 Beaverhall Place, Thunder Bay
Legal Description	Lot 13, Plan W796, (Neebing), City of Thunder Bay
PIN#	620430045
Registered Owner	Ontario Hydro (Title Search)
Easements	Nil
Right of Ways	Nil
Relevant Encumbrances	Nil
Title Search Completed	Yes – See Attached

10.2 Assessment Information

Roll #	580404020113001
2016 Assessed Value	$1,645,000
Comparison with Market Value	Understated – Based on a dated 2016 assessed value date.
Comment	Assessed Value does not equate to market value as defined in this report. Assessments are updated and revised periodically and with changes in use.

10.3 Subject History

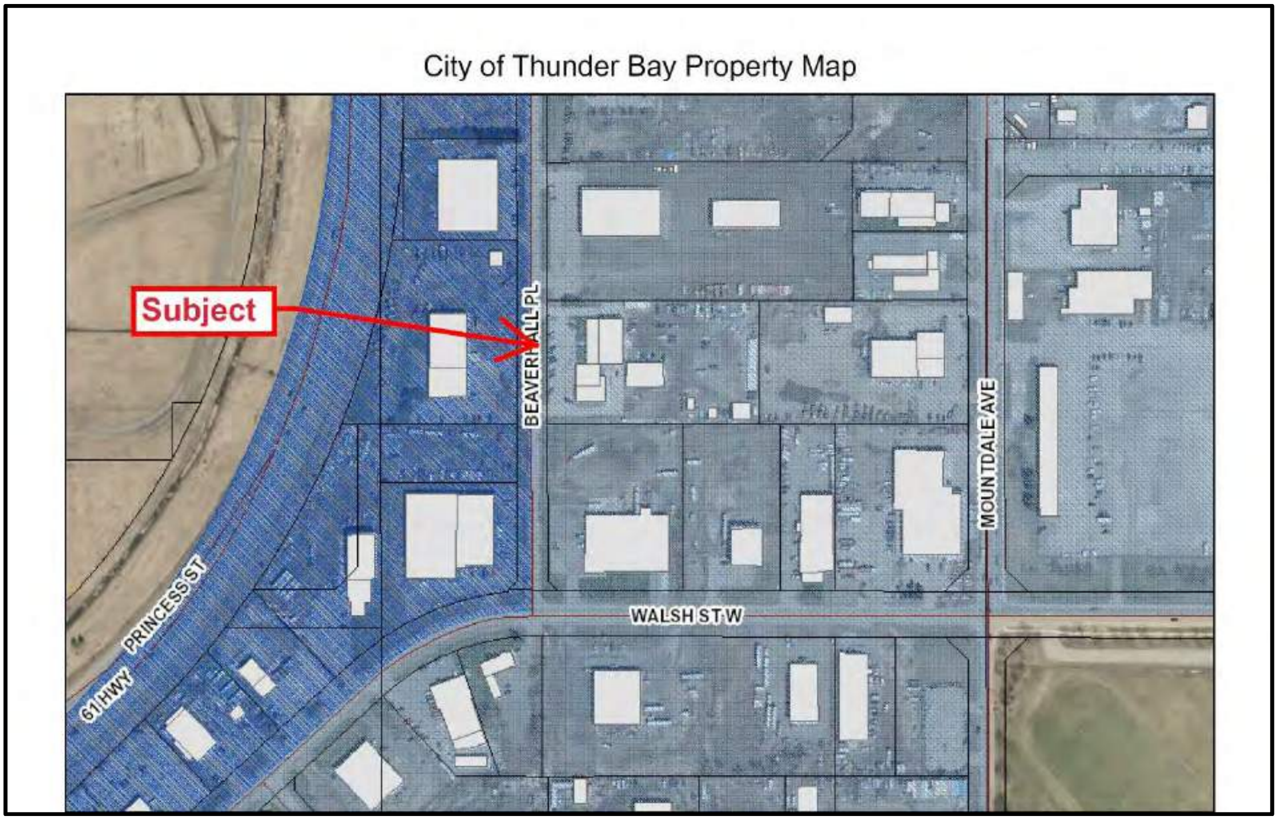
Last Transfer:	
Instrument #	TBR299917
Transfer Price	$525,000
Purchase Date	September 26, 1988
Purchaser	Ontario Hydro
Relevant Listings:	According to the public record, the subject property has not sold in the past three years. There are no other known records of the subject property being offered for sale over the same period.

11.0 Land Use Controls

11.1 Official Plan

The Official Plan sets out the longer term vision for Land Use in any given area. The purpose of an Official Plan is to provide a formally adopted text of public policies and standards as guidelines for the future development of the community.

The subject property is designated as ***"Light Industrial"*** in the Official Plan.



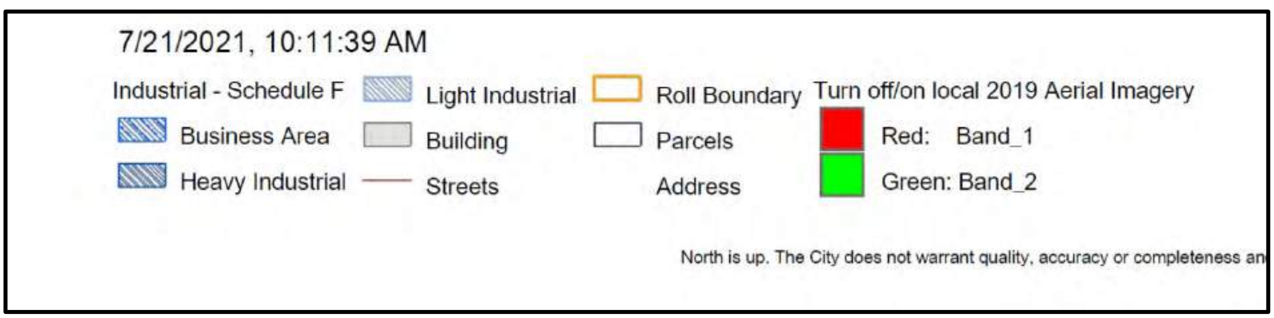


Figure 2 Source: City of Thunder Bay GIS

Official Plan - Light Industrial Policy Excerpt

LIGHT INDUSTRIAL

The intent of this designation is to provide for the development of a broad range of industrial activities which are likely to have a minimal impact on surrounding uses. Uses permitted may include the processing, treatment, storage, shipment, or manufacture of goods and materials. The operations of permitted industrial uses should be conducted substantially within enclosed buildings. Uses having similar characteristics will be encouraged to develop in clusters or on adjacent properties. Where practical, a gradation of uses may be encouraged so that those industries likely to have the least impact on neighbouring uses are directed to areas adjacent to other forms of development.

Development Standards

Areas designated as Light Industrial will, in most cases, be located where there is access to arterial roads, railways, and/or airport facilities, and where industrial traffic will be directed away from residential areas. Service facilities and storage areas shall be located in the rear yard or shall be fully screened from street view, only visitor parking shall be permitted in the front yard or exterior side yard.

11.2 Zoning

Zoning By-laws are a set of regulations governing land uses that implement the policies in the Official Plan. A Zoning By-law contains specific requirements that provides a way of managing land use and future development that is legally enforceable. It also protects property owners from conflicting land uses. Zoning By-laws cover such items as the use of land, where buildings and other structures may be located, the types of buildings that are permitted and how they may be used, lot sizes and dimensions, parking requirements, landscape and buffer requirements, building heights and setbacks from property lines.

According to the prevailing City of Thunder Bay Zoning By-law (ZBL), as amended, the subject property is zoned ***"IN2 - Medium Industrial Zone"***. The ZBL in effect at the effective date of valuation is understood to have been #100-2010.

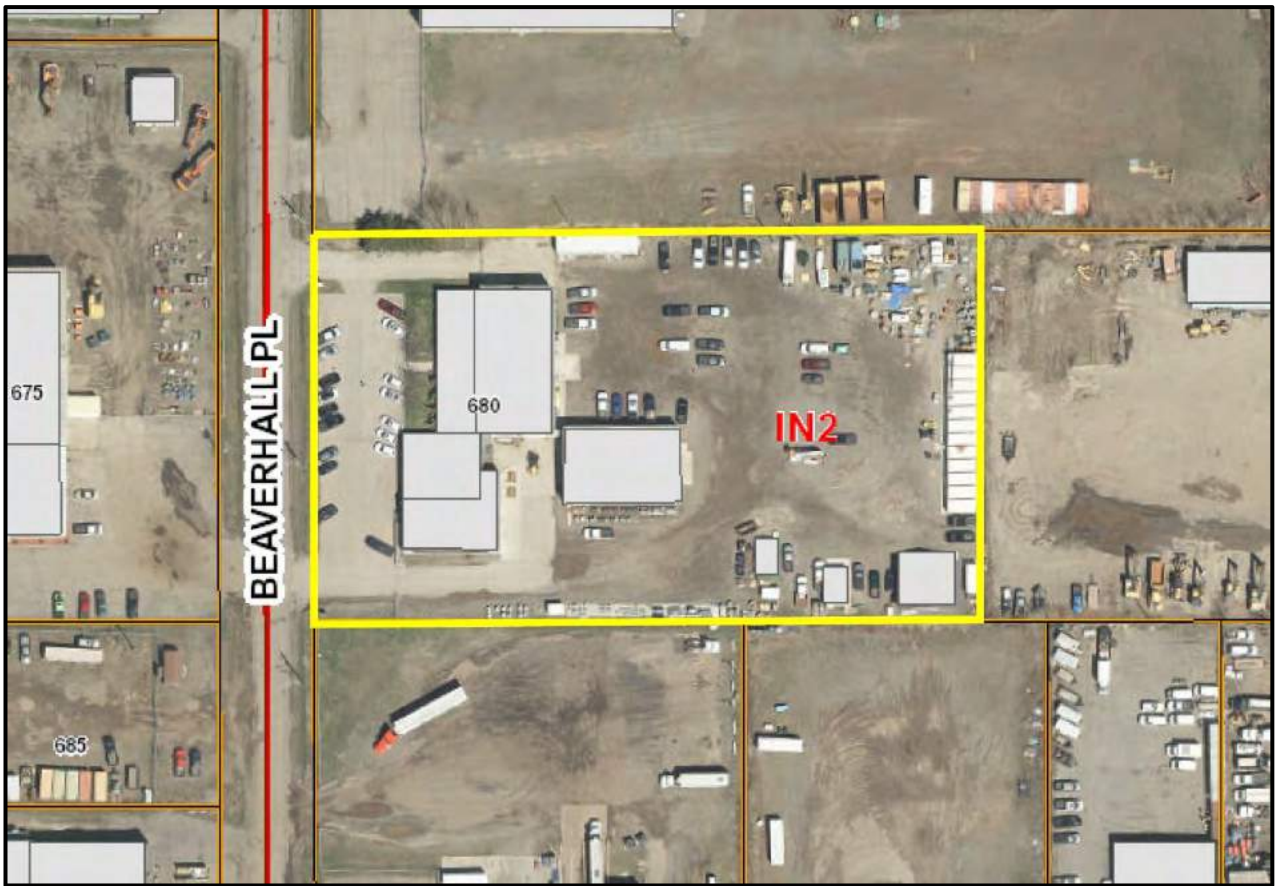


Figure 3 Source: City of Thunder Bay GIS

- ***Permitted Uses***

SECTION 27 **IN2 – MEDIUM INDUSTRIAL ZONE**

27.1 **a) Permitted USES**

No person shall use any land or erect or use any BUILDING or STRUCTURE within any IN2 ZONE for any purpose or USE other than the USES listed below:

- ANIMAL BOARDING FACILITY;
- ANIMAL CARE FACILITY;
- Car rental agency;
- EMERGENCY SERVICES FACILITY;
- EQUIPMENT SERVICE AND RENTAL ESTABLISHMENT;
- FUEL BAR;
- HOME IMPROVEMENT STORE;
- INDUSTRIAL CENTRE;
- INDUSTRIAL SCHOOL;
- LIGHT INDUSTRIAL USE;
- MEDIUM INDUSTRIAL USE;
- MOTOR VEHICLE SALES OR RENTAL ESTABLISHMENT;
- MOTOR VEHICLE SERVICE STATION;
- MOTOR VEHICLE BODY REPAIR SHOP;
- OUTDOOR STORAGE;
- PRIVATE UTILITY;
- RESTAURANT;
- SERVICE SHOP;
- TRANSPORT TERMINAL; or
- UTILITY.

b) Additional Permitted USES:

In addition to the USES permitted in Section 27.1(a), the following USES are permitted on LOTS with full MUNICIPAL SERVICES:

- Car Wash; or
- DRY-CLEANING PLANT.

- ***Regulations***

27.2 REGULATIONS

27.2.1 Building Envelope REGULATIONS: In addition to all other REGULATIONS of this BY-LAW, no person shall, within any IN2 ZONE, use any land, or erect or use any BUILDING or STRUCTURE, except in compliance with the building envelope REGULATIONS in Table 27.2.1.

To use the table, locate the applicable building envelope REGULATION in the first column of the table. Read across the table and locate the measurement in the same row as the applicable REGULATION that is within the column for the applicable type of LOT in question. The measurement in that table cell is the one that applies to the REGULATION in the first column and the type of LOT in question.

Table 27.2.1	LOTS WITH MUNICIPAL WATER SERVICES AND WITHOUT MUNICIPAL SEWAGE SERVICES	LOTS WITH MUNICIPAL SERVICES
Minimum REQUIRED LOT FRONTAGE	60.0m	22.0m
Minimum REQUIRED LOT AREA	10,000m^2	930.0m^2
Minimum REQUIRED FRONT YARD	9.0m	6.0m
Minimum REQUIRED REAR YARD	9.0m	6.0m
Minimum REQUIRED EXTERIOR SIDE YARD	6.0m	6.0m
Minimum REQUIRED INTERIOR SIDE YARD	3.0m	3.0m
Minimum LANDSCAPED OPEN SPACE	LANDSCAPED OPEN SPACE in the form of a 6.0 m wide strip along all LOT LINES abutting a RESIDENTIAL ZONE and LANDSCAPED OPEN SPACE in the form of a 3.0 m wide strip along all LOT LINES abutting a STREET LINE	LANDSCAPED OPEN SPACE in the form of a 6.0 m wide strip along all LOT LINES abutting a RESIDENTIAL ZONE and LANDSCAPED OPEN SPACE in the form of a 3.0 m wide strip along all LOT LINES abutting a STREET LINE
Maximum HEIGHT	15.0m	17.0m

27.2.2 SEPARATION DISTANCE between MAIN BUILDINGS

No person shall use any land or erect or use any BUILDING or STRUCTURE in an IN2 ZONE such that there is a SEPARATION DISTANCE of less than 6.0m between MAIN BUILDINGS on the LOT.

Table 1

Standard	IN2 – Medium Industrial	Subject Property
Lot Area (min.)	930 m2	Appears to Comply
Lot Frontage (min.)	22.0 m	Appears to Comply
Front Yard (min.)	6.0 m	Appears to Comply
Exterior Side Yard (min.)	6.0 m	Appears to Comply
Interior Side Yard (min.)	3.0 m	Appears to Comply
Rear Yard (min.)	9.0 m	May Not Comply to Workshop
Building Height (max.)	15.0 m	Appears to Comply

11.3 Summary

The land use, zoning and restrictions have not been confirmed with a municipal planner unless expressly stated. We have relied upon online documents through the municipal website or our internal library.

The subject appears to comply with the relevant Land Use regulations in terms of use. The subject appears to comply with most relevant Land Use regulations in terms of restrictions. The setback of the workshop appears to be slightly under the required 9.0m rear yard setback. Also, the separation distance of the main building to the warehouse is under the required 6.0 metres. The subject property is an existing facility and we do not expect these items to affect the continued use of the property.

12.0 Area and Neighbourhood Data

12.1 General Area

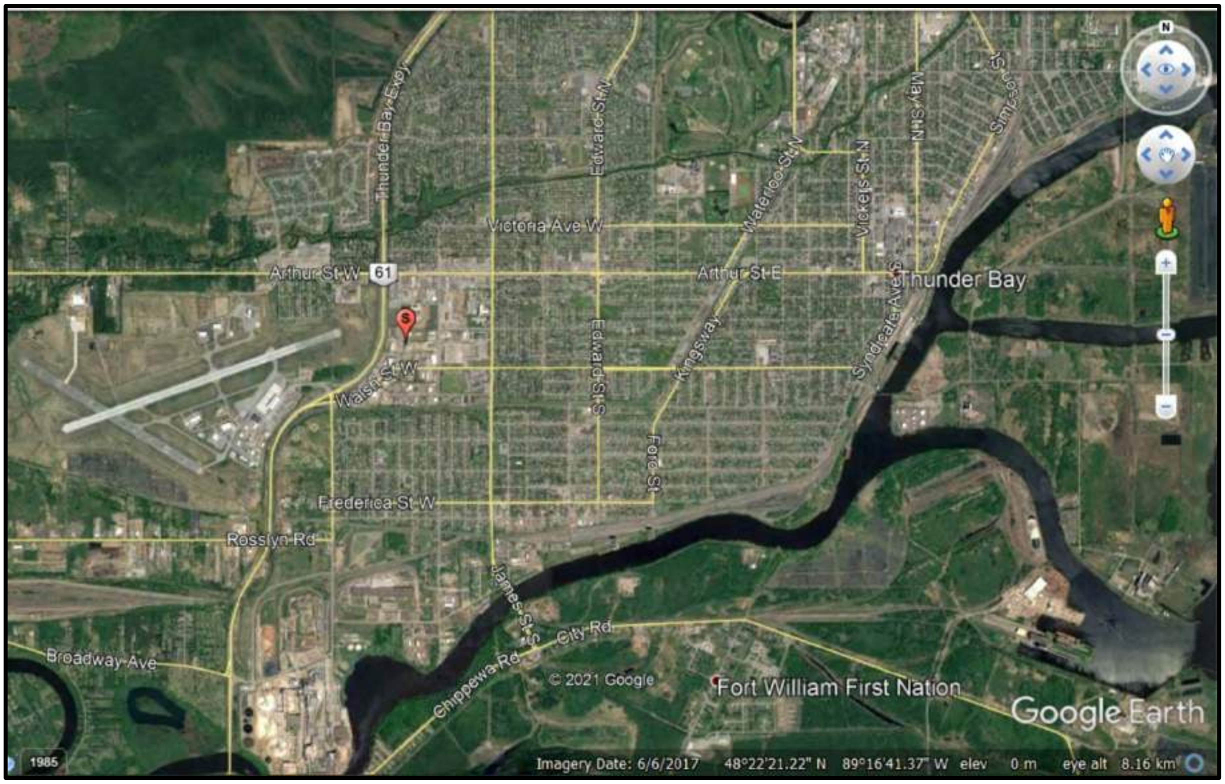


Figure 4 Source: Google Earth

Positioned on the western shore of Lake Superior, the City of Thunder Bay is the central urban focus for Northwestern Ontario. It is the predominant urban centre for supply and service to a region that extends west for 375 miles (600 kilometres) to the Province of Manitoba; east for 250 miles (400 kilometres) to the District of Algoma, Ontario; and north for varied and considerable distances by road or air to several small communities and a number of remote access First Nation Reserves.

The economy of Thunder Bay was founded around being the most western Canadian terminus of the Great Lakes and St. Lawrence Seaway system, as well as the harvest and process of natural resources (timber and minerals) from a vast and surrounding hinterland region. This economy has been in transition since the late 1970's, with reduced use of waterway transportation and significant but variable changes in the nature of mining and forestry.

Over the past 40 years, changes in mining and forestry have had a more noticeable impact on the surrounding region of Northwestern Ontario. However, they have also caused changes in the nature of employment and business in Thunder Bay. Since the 1970's, the Thunder Bay economy has undergone a slow and occasionally painful transition from transportation and resource harvest and production, to regional service and supply.

Changes in Thunder Bay Population

Referencing information published by Statistics Canada, population changes for Thunder Bay and its surrounding Census Metropolitan Area are tracked as follows.

The Thunder Bay CMA extends east from the City Limits to include the adjoining rural Municipality of Shuniah, and west to include the rural Municipality of Oliver-Paipoonge and the rural Townships of O'Connor, Marks and Conmee. It extends north and northwest to include the rural Townships of Gorham and Ware, Jacques, Fowler and Dawson Road Lots. It extends south and southwest to include the rural Township of Gillies and the Municipality of Neebing.

Table 2

	Thunder Bay City	Thunder Bay CMA
Census Year 2001	109,016	121,986
Census Year 2006	109,140	122,907
Census Year 2011	108,359	121,596
Census Year 2016	107,909	121,621

The population of both the City of Thunder Bay and the Thunder Bay CMA have remained stable from 2001 to the most recent Census in 2016, with no population growth observed.

EXHIBIT 31 – POPULATION PROJECTIONS

Scenario	2016 (Census)	2019 (forecast)	2051 (forecast)	Change (2019-2051)
Base Case	107,810	108,935	124,241	15,306
Low Case	107,810	108,122	113,863	5,741
High Case	107,810	109,751	135,535	25,784
High+ Case	107,810	109,751	155,802	46,051

Figure 5: Employment Land Strategy 2020

12.2 ICI Land Supply & Demand

The City of Thunder Bay undertook an Employment Land Strategy Study in 2020. This study was completed by Cushman & Wakefield. The following represent excerpts from the Cushman & Wakefield an Employment Land Strategy Study 2020 dated September 30, 2020.

Land Demand

> *The employment by industry projection can be translated into a forecast of land needs by identifying the type of buildings that are required for each category of employment. The following highlights the conclusions of our land demand analysis.*
>
> *Industrial – Using a benchmark industrial employment density and a typical industrial building site coverage ratio, there is demand for approximately 30 gross hectares of industrial land through the 2051 forecast horizon.*
>
> *Office – Guided by recent office development formats in the city, employment in sectors that are associated with office-type space demand is anticipated to generate demand for 7 gross hectares for office uses by 2051.*

Institutional – In discussion with the city's largest institutional employers, there is no identified near or medium-term requirement for additional Institutional-designated lands. Large institutional sites/campuses all offer excess lands that can accommodate future development, and on-site intensification is their principal focus of growth.

Retail-Commercial – The Consultant Team prepared two retail-commercial land demand scenarios that are guided by the same population forecast, but different assumptions about the amount of retail space demanded per capita. New retail-commercial uses will continue to emerge, and it is highly likely that some buildings within the existing inventory will become obsolete, and repurposed to a mixed-use or other form of redevelopment. It is recommended that the City plan for 25 gross hectares of retail-commercial land through 2051.

Our analysis has identified a considerable supply of vacant, designated employment lands in the City of Thunder Bay. The demand assessment indicates that future employment land requirements can be accommodated on existing sites. Therefore, there is no identified need to consider the conversion of any non-employment lands for employment purposes.

Land Supply

At an aggregate level, there is a vast supply of remaining undeveloped, designated industrial lands across Thunder Bay. This is particularly the case for Light Industrial-designated sites (520 vacant hectares) and Heavy Industrial-designated sites (over 200 vacant hectares), but the comment is also applicable to lands designated as Business Area (nearly 50 vacant hectares). Notably, this analysis does not even factor in existing occupied lands which may represent opportunities for intensification, or potentially redevelopment. A legacy of contamination of lands and buildings is a challenge in Thunder Bay on certain sites where there is a history of heavy industrial activity. Further, there are serviced employment lands at Thunder Bay International Airport that are suitable for industrial development – although these lands are not available for acquisition; these would be subject to a land lease arrangement.

While there are large concentrations of both Light Industrial and Heavy Industrial-designated vacant lands in areas on the city's periphery (including Mission and McKellar Islands), site visits by the Consultant Team have revealed a relative scarcity of vacant industrial lands in some of the more centrally-situated existing (built-up) employment areas. Of note, Innova Business Park represents a sizable inventory of remaining undeveloped lands that are centrally located, and more proximate to labour compared to other undeveloped planned industrial areas. Accordingly, the Light Industrial and Business Area lands located in Innova Business Park and to the north along Thunder Bay Expressway, Burwood Road, and Golf Links Road represent the best remaining undeveloped employment lands in the city, from a locational and market perspective.

Building Permit Activity

3.5 Non-Residential Building Permit Activity

The Consultant Team reviewed building permits provided by City staff for the period from January, 2010 – December, 2019. Over this past decade, some 2,000 non-residential permits were issued across the City of Thunder Bay. We have classified the permits into four categories: Commercial, Institutional, Industrial, and Other (the “Other” category captures properties such as utilities, performing arts centres, transportation terminals, and other mixed uses that do not fall into the prior three categories). The following are notable observations from our analysis:

- New building permits accounted for nearly one-half of the total permit value ($440 million), but represented just 12% of total permits, by count of permit.
- Permits for additions and alterations to properties – reflecting reinvestment in the stock of non-residential buildings – totaled $488 million, and an 88% share of total activity, by count of permits.
- By count of permit, the Commercial category accounted for just over one-half of total permits (52%), followed by Institutional (21%), and Industrial (13%). Buildings in the Other category represented a 14% share of the total activity.
- Commercial permits totaled $400 million in value, split evenly between new and addition/alteration work.
- Institutional permits totaled $337 million, with addition/alteration work representing a slight majority of the total permit value.
- Industrial permits totaled $57 million value, with two-thirds of the value being associated with new construction activity.

EXHIBIT 13 – VALUE AND NUMBER OF PERMITS BY BUILDING TYPE

Building Type	New		Addition/Alteration		Total	
	Value ($Millions)	#	Value ($Millions)	#	Value ($Millions)	#
Commercial	$201	89	$199	961	$400	1,050
Institutional	$149	15	$188	396	$337	411
Industrial	$38	116	$19	136	$57	252
Other	$52	14	$82	274	$134	288
TOTAL	**$440**	**234**	**$488**	**1,767**	**$928**	**2,001**

Source: City of Thunder Bay and Cushman & Wakefield

Figure 6: Employment Land Strategy 2020

12.3 Area Summary

There is a substantial supply of undeveloped industrial lands within Thunder Bay, however sites within areas that are serviced and within the core central employment areas are more limited. Absorption of Industrial land has been relatively slow with only 14 new facilities constructed between 2010 and 2019. Although absorption has been limited, it has been reported by several developers and real estate brokers that there appears to be some increased demand for industrial sites in the community.

12.4 Neighbourhood

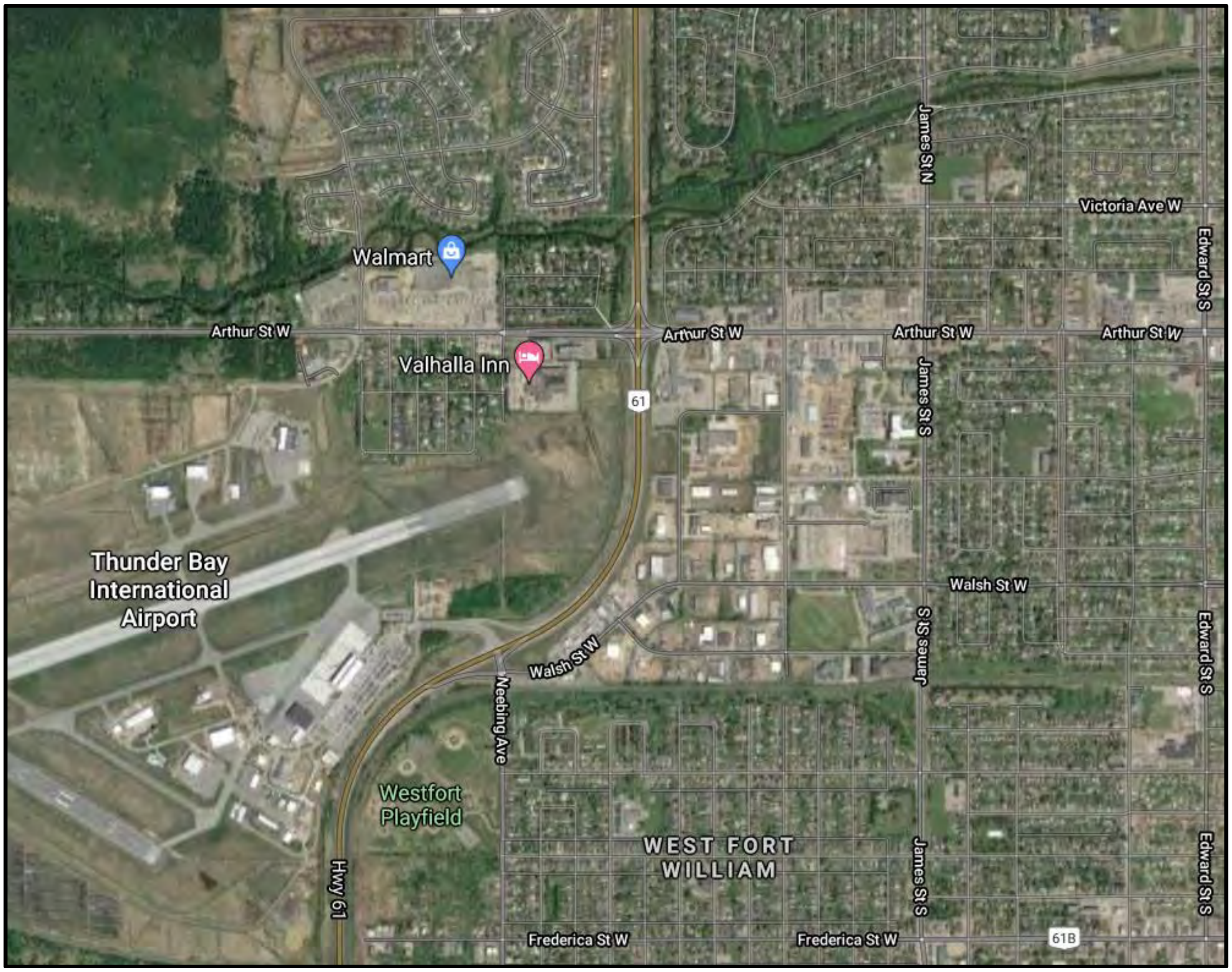


Figure 7 Source: City of Thunder Bay GIS

The subject property is in the southern portion of the City of Thunder Bay, within a concentration of industrial development known as the Beaverhall Industrial Area. This neighbourhood is generally bound by Highway 61 and Thunder Bay Airport to the west, Arthur Street to the north, James Street to the east and a rail line to the south. The neighbourhood is primarily comprised of general industrial uses with some service industrial / commercial uses. Arthur Street to the north is developed with commercial uses such as restaurants, gas stations and hotels. This location benefits from good access to Thunder Bay Airport and major transportation corridors.

Table 3

Neighbouring Uses	
North	To the immediate north is a large industrial property that has remained mostly vacant in recent history followed by a large equipment service shop.
South, West & East	Similar general industrial facilities.
Trends	
General Trend	Stable
Anticipated public / private improvements	The member is not aware of any anticipated public or private improvements that significantly impact the current short market value of the subject property.

13.0 Characteristics of the Market

13.1 National Economic Overview

The National Bank Monthly Economic Monitor (June 2021) provides the following:

- *The daily number of new cases of Covid-19 declared around the world has been declining markedly over the last month. In the developed economies, the drop can be attributed in large part to an acceleration of vaccine rollouts encouraging an outlook of fuller and more lasting reopening of economies. Elsewhere, improvement in public health is due rather to reinforcement of physical distancing rules, especially in India where in late April a flare-up of cases forced the reintroduction of strict lockdowns in some regions. Since access to vaccines is much more limited in emerging countries, herd immunity is unlikely before 2022. Developing countries will accordingly remain at greater risk of pandemic outbreaks in the coming months, a factor that could mean higher volatility of growth rates. We nevertheless continue to expect a solid rebound of the global economy in 2021 and are maintaining our forecast of 6.0% growth for the year. In fact, our confidence in a vigorous recovery has risen, since distribution of vaccines has greatly reduced economic uncertainty and downside risks for growth.*
- *The latest U.S. economic indicators confirm what has been our outlook for a few months now: a very strong revival stimulated by highly accommodative monetary and fiscal policies. Nonfarm payrolls grew 559,000 in May, less than the expected 675,000 but more than the months before, suggesting a slow but steady revival of the labour market in step with reopening of the economy. Also in May, headline 12-month CPA inflation was 5.0%, the highest in 13 years. For the CPI excluding food and energy the 12-month rise was 3.8%, the highest since June 1992. The three-month-annualized readings are still more impressive: headline inflation 8.4%, core inflation 8.3%. Up to now, the bulk of inflationary pressure has come in the goods-producing sector, but inflation could also take off in services if consumers decide, as we think they will, to spend more on activities unavailable in recent months (e.g. restaurant meals and travel). For the U.S. economy as a whole, we have left our forecast of 6.9% growth this year unchanged but have increased 2022 growth to 4.3% to reflect further government spending on infrastructure and social programs. In our projections, U.S. real GDP will be back to its potential by the third quarter of this year.*
- *Early in 2021, as the two largest provinces in Canada decreed shutdowns of non-essential businesses, public health conditions seemed to augur little good for the Canadian economy in Q1. And all the other G7 countries except the U.S. did have GDP declines during the quarter. In Canada, however, not only did the contraction that many had apprehended not materialize, but the quarter ended with very solid real growth of 5.6% annualized, a showing that put the Canadian economy in a leading position. In real terms its output came within 1.7% of its peak pre-pandemic quarter (Q4 2019) – second-best in the G7. In nominal terms the Q1 growth was even more spectacular taking nominal GDP to a best-in-G7 3.0% above its pre-recession peak. This month we are keeping our forecast of real growth in 2021 at 6.0%. after a pause in the recovery in Q2 due to public-health measures and to production backlogs in the auto industry due to microchip shortages, impressive growth can be expected to continue as vaccination picked up speed allowing the reopening of services that entail physical proximity. Our forecast for 2021 growth in nominal terms is now 12.6%, unseen in 40 years.*

Canada
Economic Forecast

(Annual % change)*	2018	2019	2020	2021	2022	2020	Q4/Q4 2021	2022
Gross domestic product (2012 $)	2.4	1.9	(5.3)	6.0	4.0	(3.1)	5.2	2.9
Consumption	2.5	1.6	(6.0)	5.0	6.2	(4.4)	5.3	5.1
Residential construction	(1.7)	(0.2)	4.1	17.9	(5.1)	14.5	2.7	(4.3)
Business investment	3.1	1.1	(13.6)	0.1	5.7	(13.9)	4.8	4.8
Government expenditures	3.2	1.7	0.4	4.8	1.7	2.4	2.9	1.5
Exports	3.7	1.3	(10.0)	5.9	5.0	(7.4)	5.2	4.7
Imports	3.4	0.4	(11.2)	7.9	5.3	(5.9)	4.8	5.1
Change in inventories (millions $)	15,486	18,766	(15,937)	4,134	13,617	(287)	16,000	13,160
Domestic demand	2.5	1.4	(4.3)	5.6	3.7	(2.0)	4.3	3.1
Real disposable income	1.5	2.2	9.5	(0.0)	(0.6)	7.4	(0.5)	1.1
Employment	1.6	2.2	(5.1)	4.4	2.8	(2.9)	3.2	2.0
Unemployment rate	5.9	5.7	9.6	7.7	6.3	8.8	6.6	6.1
Inflation	2.3	1.9	0.7	2.7	2.5	0.8	3.1	2.3
Before-tax profits	3.8	0.6	(4.0)	33.4	2.2	9.4	16.8	4.0
Current account (bil. $)	(52.2)	(47.4)	(40.1)	5.0	(38.0)	....	....	....

* or as noted

Financial Forecast**

	Current 6/11/21	Q2 2021	Q3 2021	Q4 2021	Q1 2022	2020	2021	2022
Overnight rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.75
3 month T-Bills	0.11	0.10	0.15	0.15	0.20	0.07	0.15	0.70
Treasury yield curve								
2-Year	0.32	0.30	0.35	0.45	0.65	0.20	0.45	1.20
5-Year	0.83	0.85	1.00	1.20	1.35	0.39	1.20	1.80
10-Year	1.37	1.40	1.55	1.75	1.90	0.68	1.75	2.20
30-Year	1.93	1.95	2.05	2.15	2.25	1.21	2.15	2.45
CAD per USD	1.21	1.19	1.17	1.20	1.21	1.27	1.20	1.23
Oil price (WTI), U.S.$	71	66	72	75	70	48	75	65

** end of period

Quarterly pattern

	Q1 2020 actual	Q2 2020 actual	Q3 2020 actual	Q4 2020 forecast	Q1 2021 forecast	Q2 2021 forecast	Q3 2021 forecast	Q4 2021 forecast
Real GDP growth (q/q % chg. saar)	(7.9)	(38.0)	41.7	9.3	5.6	1.2	7.4	6.6
CPI (y/y % chg.)	1.8	0.0	0.3	0.8	1.4	3.2	3.2	3.1
CPI ex. food and energy (y/y % chg.)	1.8	1.0	0.6	1.1	1.0	2.0	2.3	2.2
Unemployment rate (%)	6.4	13.1	10.1	8.8	8.4	8.2	7.4	6.6

National Bank Financial

Figure 8 Source: National Bank Monthly Economic Monitor June 2021

13.2 Real Estate Trends – MLS® Residential Average Price Trend (CREA):

There are no reliable statistics available for employment lands in the subject market place. To provide some context of the real estate market in Thunder Bay we reference the following statistics provided by CREA.

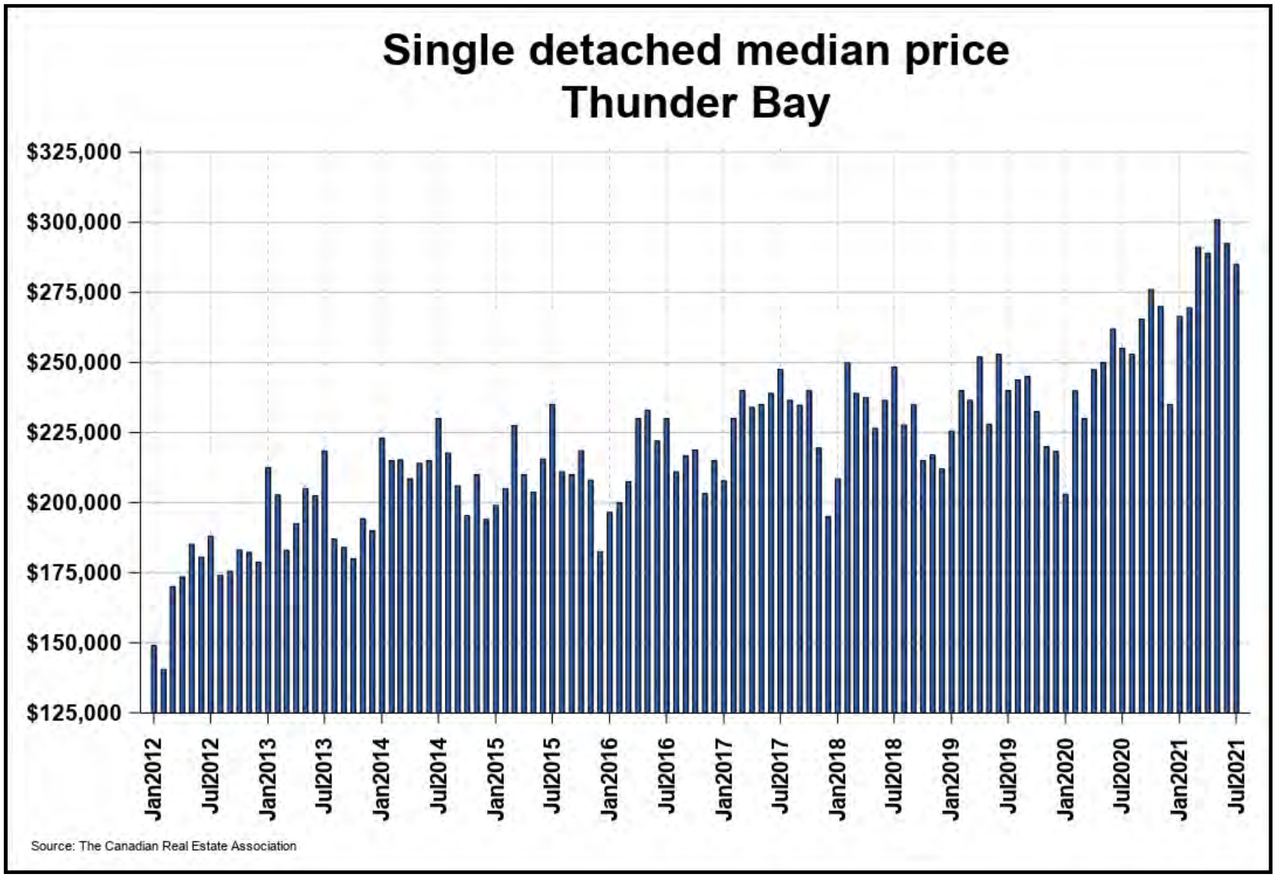


Figure 9: Source - CREA

On a year-to-date basis, single detached home sales totaled 651 units over the first seven months of the year. This was an increase of 79.8% from the same period in 2020.

The median sale price for single detached homes sold in July 2021 was $285,000, a gain of 11.7% from July 2020.

The more comprehensive year-to-date median price was $288,000, increasing by 16.9% from the first seven months of 2020.

Single detached properties spent less time on the market before selling in July 2021 than they had a year earlier. The median number of days on market for single detached home sales was 15 in July 2021, down from the 18 days recorded in July 2020.

The dollar value of all single detached home sales in July 2021 was $33.2 million, a sharp decrease of 10.5% from the same month in 2020.

14.0 Site Description

14.1 Site Details

Table 4

Item	Description
Area	2.82 acres (11,428 m2)
Frontage	270 feet +/-
Shape / Location	The subject is an interior site with a rectangular shape.
Topography	The site is generally level, cleared and fully graded.
Road Type	The site fronts Beaverhall Place, a paved two-lane collector road.
Entrances	Access to the property is provided by two entrances to Beaverhall Place.
Services / Utilities	Municipal Sewer and Well; Gas; Hydro
Site Improvements	The property is improved with a paved parking lot at the front of the building. This parking lot provides for 29 spaces including 1 barrier free. Access to the rear yard is provided through gated laneways on the north and south side of the building. The rear yard is fully fenced and graded with a gravel yard. The yard has some pole mounted lights and vehicle plug-in stations. A concrete pad is found along the southern property limit had is utilized for storage of transformers. The front yard is landscaped with maintained lawn and some trees. The property is also improved with two storage sheds including a 440 sq.ft. steel environmental storage building and a 400 sq.ft. steel storage building. Both buildings have roll up doors. Additional storage is provided by 12 seacans along the rear however these are considered equipment and not included in this valuation. This is also the case for an office trailer present on site.

14.2 Easement, Right of Way or Other Restrictions

There are no known easements, right of way or restriction which adversely impacts the value of the property.

14.3 Drainage and Soil Conditions

There are no known soil or drainage problems associated with the site, however, soil tests have not been made. We assume no responsibility for matters relating to the soil quality or any contaminants that may or may not be present.

Unless otherwise noted, at the time of our inspection we did not observe any obvious signs of contamination or environmental concerns. The member is not qualified to comment on environmental issues that may affect the market value of the property appraised, including but not limited to pollution or contamination of land, buildings, water, groundwater or air. Unless expressly stated, the property is assumed to be free and clear of pollutants and contaminants, including but not limited to moulds or mildews or the conditions that might give rise to either, and in compliance with all regulatory environmental requirements, government or otherwise, and free of any environmental condition, past, present or future, that might affect the market value of the property appraised. If the party relying on this report requires information about environmental issues then that party is cautioned to retain an expert qualified in such issues. We expressly deny any legal liability relating to the effect of environmental issues on the market value of the subject property.

14.4 Aerial Image

Figure 10

14.5 Yard Site Plan

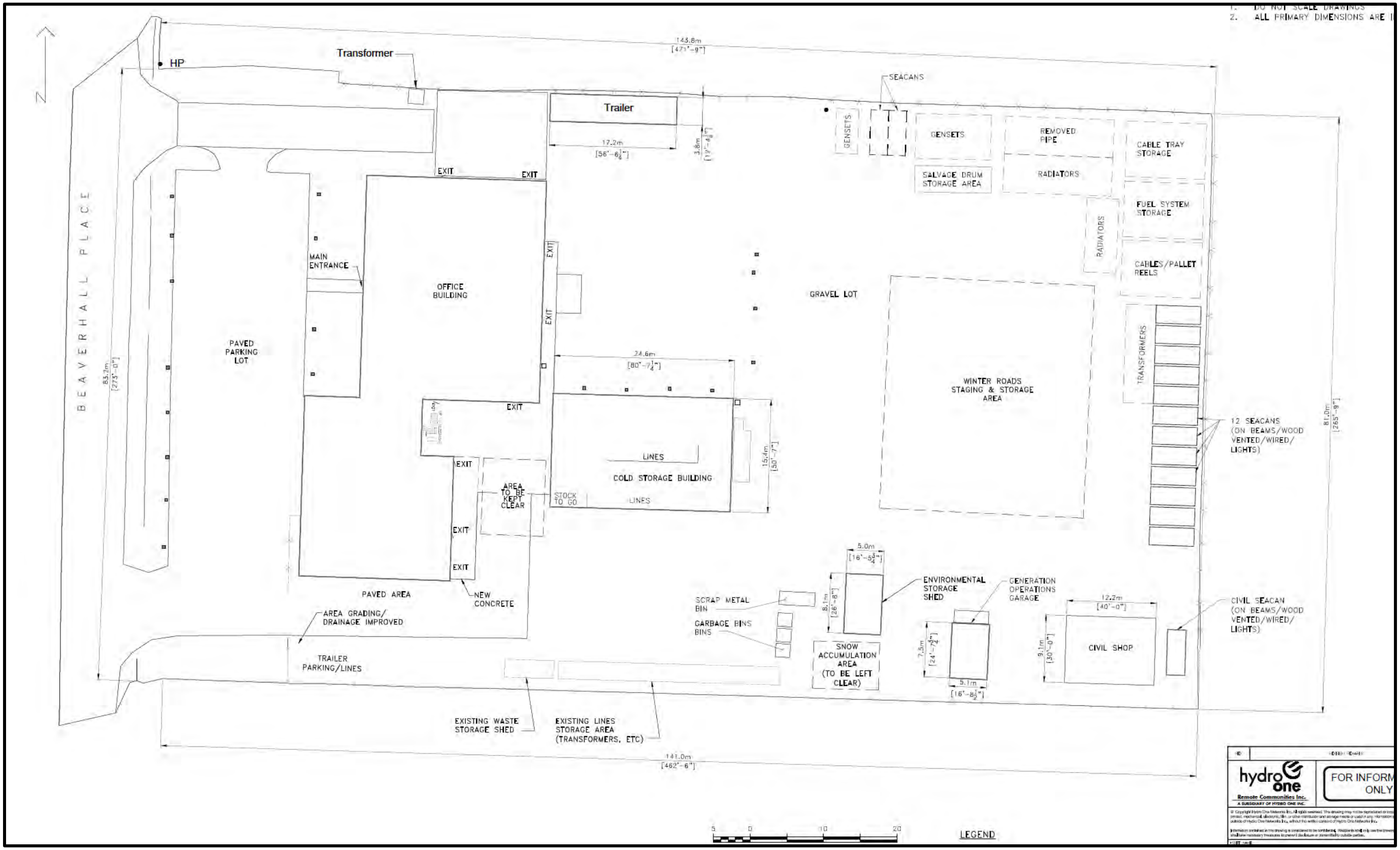


Figure 11 Source: Client

15.0 Building Summary

15.1 Primary Building Description

The subject primary building is currently developed as an office / service facility. We noted the following components in place at the time of inspection:

Table 5

Item	Description
Type or Design	Office / Service Building
Actual Age	Original Built 1978 +/- - Approximately 40 Years *It appears that the building was constructed in stages.
Effective Age	20 to 25 years +/-
Gross Floor Area (sq.ft.)	15,570 sq.ft.
Exterior Closure	Concrete Block, Brick & Steel
Main Floor Structure	Poured Concrete
Superstructure	Block & Steel Frame
Roof Structure	Steel Open Web Joist
Roof Covering	Membrane
Roof Age - Estimated	15 years +/-
Roof Condition	Most of the roof appears to be in average to good condition.
Windows	Double Glazed - Aluminium Frame
Plumbing	Copper and Plastic
Electrical Service	600-volt; 800-amp service
HVAC	Forced Air with A/C; Radiant Gas Heat; Ceiling Mount Forced Air Units; Automatic Ventilation in Service Shop
Sprinklers	No
Drive-in Doors	3 x 16' high; 1 x 10' high
Truck Level Doors	None
Clear Ceiling Height	Service Garage – 20' +/-; Storage Room – 12' +\-

Building Layout and Description

The main office / service industrial building is comprised of approximately 8,790 sq.ft. of office space and 6,780 sq.ft. of service shop, storage, and shop office area.

The office area is on two levels with approximately 6,390 sq.ft. on the main level and 2,400 sq.ft. on the upper level. The upper level was formerly storage mezzanine however it is now finished to an office standard and has been included in the building area. The main level is mostly comprised of open office area divided into workstations, a few private offices, conference room and a lunchroom. There are men's, women's and barrier free washrooms on the main level office. The main level office is finished with carpet, drywall and painted block and drop panel ceilings. The upper-level office is open office area with workstations and a large conference room. The ceiling clearance is roughly 7' to 8'. The space is carpeted with drywall walls and open painted ceilings. The office area is heated and cooled with roof mounted forced air units.

The rear service shop includes two service bays, storage and a shop office / change room area. The service bays include floor drains and are accessed by a 16’ door. One bay has a 5-ton bridge crane. This space is heated with radiant gas units. The shop office area is utilized as computer stations. The building also includes a storage area at the south side of the building. This space is accessed by a 10’ door and is heated with forced air units. Two shop offices are in this space.

Building Condition

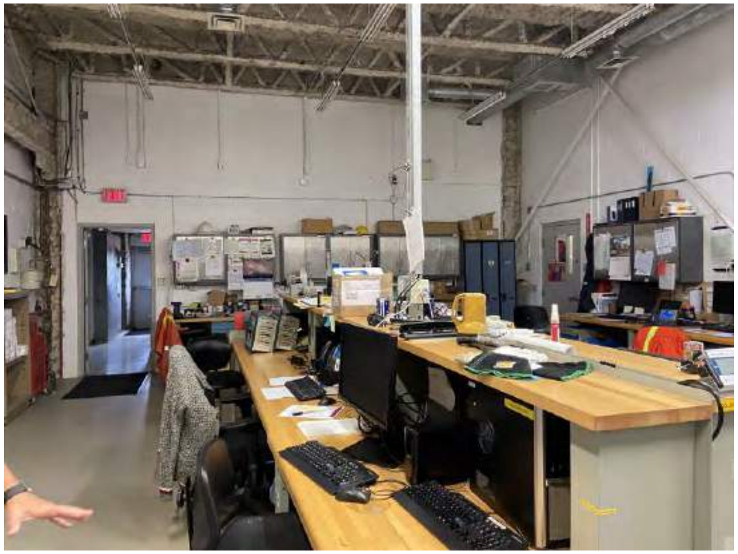
The building has been well maintained and there are no noted major repairs required at this time. The interior office finishes are in good condition. The shop space is clean and maintained. The exterior cladding demonstrates the age of the building but is in average condition.

Overall, the building is considered to be in average condition and well maintained. Some areas are considered to not fully reflect modern space such as the upper level office due to the low ceilings.

15.2 Interior Photographs

Change Rooms & Washrooms

Lunchroom



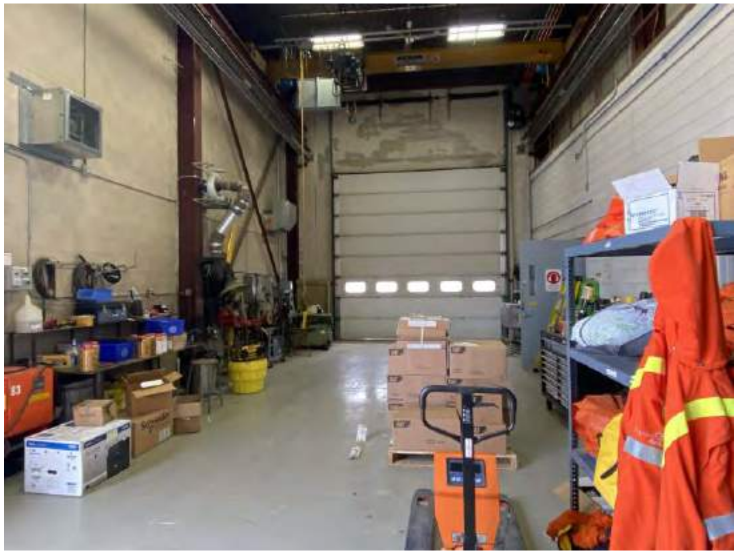
Industrial Workspace

Main Level Boardroom

Main Level Office

Mezzanine Office

Mezzanine Office Meeting Area



Service Shop Area

Storage Area

15.3 1st Floor Plan

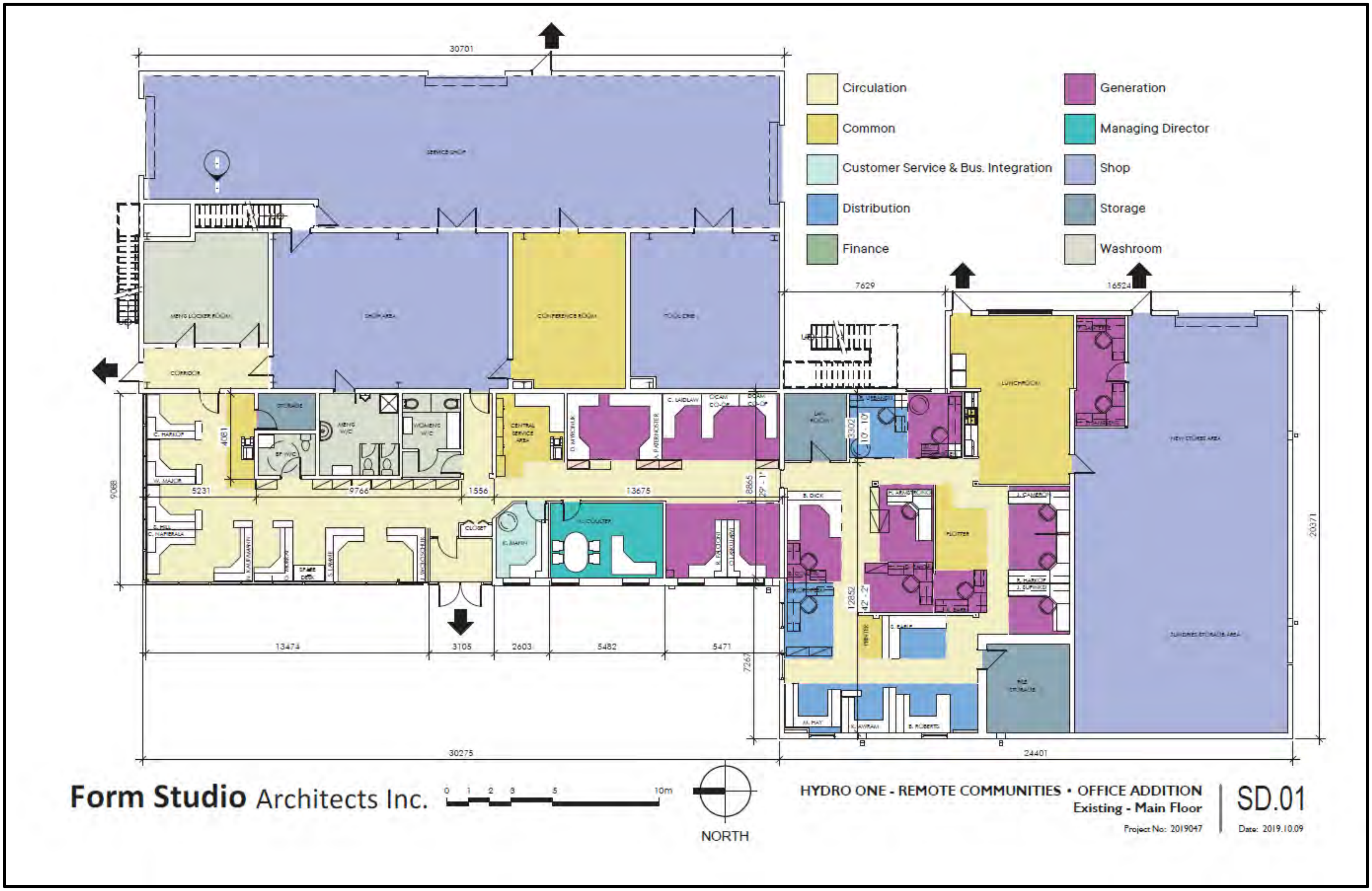


Figure 12

15.4 2nd Floor Plan

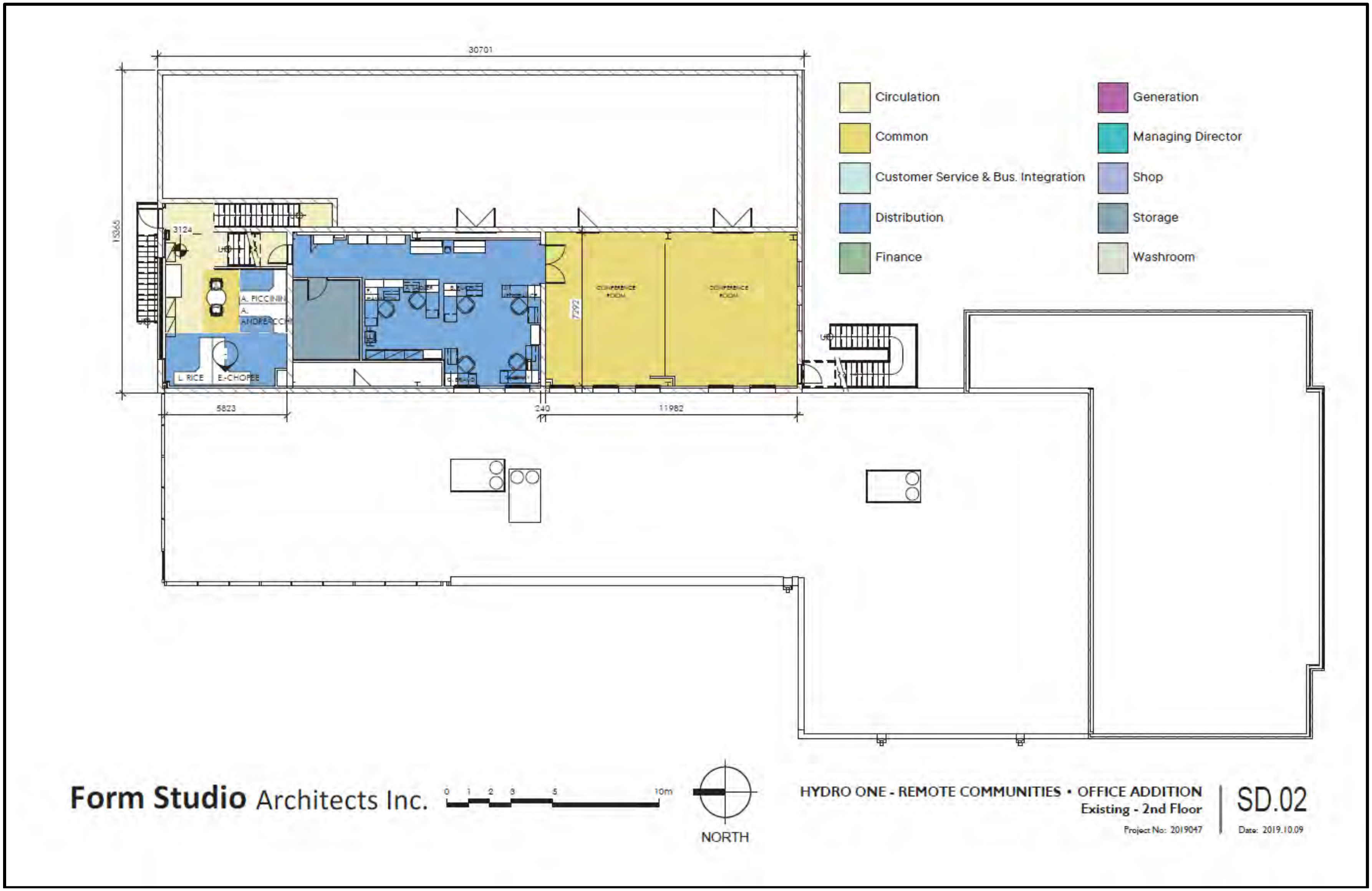


Figure 13

15.5 Warehouse Building

Table 6

Item	Description
Type or Design	Steel Storage Building
Actual Age	2000 +/-: Approximately 21 Years
Effective Age	20 years +/-
Gross Floor Area (sq.ft.)	4,065 sq.ft,
Exterior Closure	Steel Cladding
Main Floor Structure	Poured Concrete
Superstructure	Steel Frame
Roof Structure	Steel Frame
Roof Covering	Steel
Roof Age - Estimated	Original
Roof Condition	Reported to be in Good Condition
Windows	None – One wall has some translucent panels.
Plumbing	None
Electrical Service	Provided from Main Building
HVAC	None
Sprinklers	No
Drive-in Doors	2 x 16' height
Truck Level Doors	None
Clear Ceiling Height	18' +\-

Building Layout; Description and Condition

This is an unheated storage building with steel construction providing for roughly 18' clearance and fluorescent / LED lighting. Access to the building is provided by two 16' drive-in doors. The building appears to be well maintained and in average condition.

15.6 Workshop

Table 7

Item	Description
Type or Design	Wood Frame Workshop
Actual Age	2014 +/-: Approximately 7 Years
Effective Age	7 years +/-
Gross Floor Area (sq.ft.)	1,200 sq.ft.
Exterior Closure	Vinyl Cladding
Main Floor Structure	Poured Concrete
Superstructure	Wood Frame
Roof Structure	Wood Truss
Roof Covering	Steel
Roof Age - Estimated	Original
Roof Condition	Good Condition
Windows	Vinyl
Plumbing	None
Electrical Service	Provided from Main Building
HVAC	Roof Mounted Electrical Heaters; Heat Recovery Ventilation Unit; Vent Fans
Sprinklers	No
Drive-in Doors	1 x 10' height
Truck Level Doors	None
Clear Ceiling Height	12' +\-

Building Layout; Description and Condition

This is a heated workshop that is insulated and finished with drywall walls and ceilings. The building has a 1-' drive-in door and a single man door. The building is in good condition and is maintained.

15.7 Interior Photographs

Warehouse Interior

Workshop Interior

Warehouse Interior

Workshop Interior

16.0 Highest and Best Use Estimate

Highest and Best Use is defined as:

"the reasonably probable and legal use of vacant land or an improved property, that is physically possible, appropriately supported, financially feasible, and that results in the highest value."[2]

The four criteria that Highest and Best Use must meet are; legal permissibility, physical possibility, financial feasibility, and maximum profitability.

- ***Legal Permissibility***

  The Highest and Best Use of a vacant site is often dictated by the governing zoning bylaws and official plan policies. The Highest and Best Use must be legal and within the realm of probability.

- ***Physical Possibility***

  Soils, topography, drainage, parking, site planning, setbacks, etc., must be suitable for the envisioned use.

- ***Financially Feasible***

  There must be market demand for the property in its current use. If an alternate use is contemplated, there must be market support that the continued use is no longer financially feasible.

- ***Maximum Profitability***

  There must be a demand for such a use and that use must be "profitable" and such that it will deliver the highest net return for the longest period of time.

The concept of value is founded on one cardinal principle: **Utility**. For an object to have value, it must possess or be capable of providing some form of beneficial utility or enjoyment to the owner, to the user or even the casual observer of the product.

The Highest and Best Use of a vacant site is often dictated by the governing Zoning By-laws. The Highest and Best Use must be legal and within the realm of probability. There must be a demand for such a use and that use must be "profitable" and such that it will deliver the highest net return for the longest period of time.

[2] *"The Appraisal of Real Estate, Second Canadian Edition", copyright 2005 Appraisal Institute, page 12.1*

16.1 Land as if Vacant

The subject site is a 2.82-acre parcel designated Light Industrial in the Official Plan and zoned Medium Industrial. The site is cleared and graded and well suited to an industrial / employment-based use. The land use allows for a range of industrial uses including open storage. Demand for lands within the subject neighbourhood appears to be present with several parcels trading in the past couple of years.

Use of the site for an industrial use as zoned and designated is legally permissible, physically possible, financially feasible and provides the maximum profitability to the lands.

We are unaware of any use that would provide a higher return to the subject property than as zoned. Therefore, the Highest and Best Use of the subject property as if vacant is concluded to be ***development as a permitted industrial use.***

16.2 Property as Improved

The subject property "as improved" represents an industrial facility having a primary building offering a large amount of office space and service garage space, an unheated warehouse and a small workshop. The property has a large graded and fenced storage yard that includes a number of sheds and storage containers.

The subject property provides well for an industrial user requiring significant office space and a large yard storage area / equipment parking. The buildings are well maintained and offer good utility. If available on the open market it is likely that demand would be present.

The use of the improved property is legally permissible, physically possible, financially feasible and provides the maximum profitability to the lands.

We are unaware of any other use that would provide a higher return to the subject property than as currently developed as an Industrial facility. Therefore, the Highest and Best Use of the subject property as improved is concluded to be ***continued industrial use as developed.***

17.0 Appraisal Procedures

17.1 Improved Value

There are three traditional approaches to value namely: (1) The Cost Approach, (2) The Income Approach, and (3) The Direct Comparison Approach.

- ***Cost Approach***

This method uses the value produced by estimating the "Market Value" of the land as though unimproved and adding to that the cost of replacing the improvement less any accrued depreciation.

- ***Income Approach***

The Income Approach to value is the method under which the annual net income produced by a property is capitalized at an appropriate rate into an indication of value.

- ***Direct Comparison Approach***

This is the method that compares the subject to sales and listings of similar properties. The comparables are adjusted for size, quality, location, etc. to produce an indication of value of the subject.

18.0 Valuation

Given the current market conditions, location and type of property the most relevant approaches to value in this analysis are determined to be as follows:

- Cost Approach
- Direct Comparison Approach

In this instance the Income Approach has not bee utilized. Although sometimes suitable it appears that larger standalone industrial facilities such as the subject in the local market are in most instances owner occupied and are not typically acquired as income producing properties. As such we have not applied an Income Approach in this instance.

19.0 Cost Approach

19.1 Land Valuation

In this instance we have selected the Direct Comparison Approach as the best method of valuation for the subject as if vacant. The following table summarizes the sales considered in our review. Detailed sale descriptions are in the addenda of the report.

Table 8

#	Location – Thunder Bay	Lot Size (acres)	Zoning	Sale Price	Sale Date / Registration Date	Time Adjusted Rate per Acre (rounded)	Adjustments Applied			Adjusted Value Per acre
Neighbourhood Sales							Location	Site Size / Scale	Topography	
1	645 Beaverhall Place	1.81	Light Industrial	$325,000	11/26/20	$187,000				**$187,000**
2	600 Beaverhall Place	1.56	Medium Industrial	$250,000	12/04/20	$166,000				**$166,000**
3	685 Beaverhall Place	0.86	Light Industrial	$300,000	6/25/21	$350,000		↓		**$262,500**
4	625 Mountdale Ave	1.45	Medium Industrial	$167,000	5/04/16	$133,000				**$133,000**
5	625 Beaverhall Place	1.69	Highway Commercial	$300,000	9/09/14	$210,000				**$210,000**
Other Sales										
6	295 Court St S	3.48	Medium Industrial	$1,150,000	7/30/21	$330,000	↓			**$231,000**
7	Dunlop St	1.09	Medium Industrial	$151,000	3/18/21	$141,000			↑	**$183,300**
8	224 Burwood Road	2.83	Prestige Industrial Hold	$399,900	1/15/20	$154,000	↑		↑	**$215,600**

↑ - Inferior to the Subject; ↓ - Superior to the Subject

19.2 Land Value Analysis

The preceding Table outlines 8 sales of employment lands located in the City of Thunder Bay. The sales include 7 sites zoned for light or medium industrial uses and one neighbourhood sale zoned highway commercial. Five of the sales are from within the subject immediate neighbourhood while 3 are within other industrial locations throughout Thunder Bay.

Majority of the sales are relatively recent being from 2020 or 2021. Two of the sales are dated but have been included due to the location within the immediate neighbourhood. Industrial / employment land values appear to have experienced some upward pressure over the past year or so while values had been more stagnant prior to this. We have applied a time adjustment of 1.5% per annum to the end of 2019 and a 6% per annum adjustment for 2020 and 2021. Once adjusted the sale provide a time adjusted sale price range of $133,000 to $350,000 per acre.

The wide time adjusted price range is primarily a result of differences in location, topography and site size / scale. Adjustments have been applied to account for these items.

Index 1 to Index 5 are all located in the immediate area. All the sites are cleared and generally flat. Some zoning differences are present but all sites appear to provide for a range of employment uses. Index 5 is zoned for commercial, however, this is related to the former hotel use and it is likely that an alternate light industrial use would be suitable. One sale is much smaller at 0.86 acres and required and adjustment for scale. Once adjusted these sales indicate a range of $133,000 to $262,500 per acre. The lower end of the range represents a dated sale of a nearby site. Although adjusted for time the adjustment may not adequately account for changes over this extended period. The more recent sales (Index 1, 2 & 3) provide a narrower range of $166,000 per acre to $262,500 per acre.

Index 6 is the pending sale of a large parcel of employment land located on the fringe of the downtown core. This site has good exposure to a four-lane road and appears to possibly have some alternate development potential. Following an adjustment for superior exposure this sale indicates a rate of $231,000 per acre.

Index 7 is a small industrial parcel located centrally within Thunder Bay. The site is forested and required greater site works. Once adjusted this sale indicates a rate of $183,300 per acre.

Index 8 is the sale of a parcel of prestige industrial land located to the north of the subject. This site required clearing and greater site works. Once adjusted the sale indicates a rate of $215,600 per acre.

The selected comparable sales provide an adjusted range of $133,000 to $262,500 per acre. As noted, the more recent neighbourhood sales provide a range of $166,000 to $262,500 per acre. The upper end of this range reflects the sale of a small site that was purchased by a nearby industrial tenant. It is our understanding that the purchaser was somewhat motivated and we would expect a rate for the subject below this indication. The additional sales from outside the neighbourhood appear to support the indications provided by the neighbourhood sales.

Considering the available sales data, it appears that industrial lands similar to the subject are in trading in the general range of $180,000 to $240,000 per acre with upward pressure experienced in the past year. This appears to be stronger than observed in past years but is supported by the available market data. Considering the strengthening in the market, a value closer to the upper end of the range is appropriate. Therefore, we conclude a subject site value of **$220,000 per acre** equating to a site value of **$620,400**.

19.3 Improvement Value

We have utilized the "SwiftEstimator" (Marshall and Swift Cost Service) online building cost estimator. Depreciation has been applied based on an overall observed rate. The following table summarizes our estimate:

Table 9

Cost Approach Summary Table			
Item	**Area**	**Rate**	**Total**
Building Cost			
Main Office / Service Shop Building (Inc. Crane)	15,570	$171	$2,662,470
Warehouse	4,065	$97	$394,305
Workshop	1,200	$108	$129,600
Total Building Cost:			**$3,186,375**
Less: Depreciation	Main Building	55%	-$1,464,359
	Warehouse	40%	-$157,722
	Workshop	20%	-$25,920
Total Depreciation			-$1,648,001
Total Depreciated Building Cost:			**$1,538,375**
Plus: Site Improvements Depreciated:			$350,000
Plus: Land Value as if Vacant	2.82	$220,000	$620,400
Estimated Value Cost Approach (Rounded)			**$2,509,000**

20.0 Direct Comparison Approach

The Direct Comparison Approach provides a basis for value through a process of adjustments for differences between comparable sales and the subject property. In this method, similar properties recently sold or offered for sale are analysed and comparisons are made based on a number of elements of comparison. These elements include real property rights conveyed, financial terms, condition of sale, expenditures made immediately after purchase, market conditions, location, physical characteristics, economic characteristics, use and zoning, and non-realty components of value. Elements that apply can be addressed quantitatively or qualitatively.

A unit of measurement is defined as a feature of a property that can be measured, for purposes of comparison, with the same common element or component of another property. For example, a selling price per "unit" could express a figure on a per square foot basis, per acre basis, per suite basis, or per room basis.

In this approach, similar properties recently sold or offered for sale are analysed and comparisons are made based on a number of elements of comparison. Elements of Comparison include:

- ***Real Property Rights Conveyed***
  Adjustments are made under this category for items such as existence of right of ways, easements, restrictive covenants which may impact the property.

- ***Financial Terms (financing)***
  Differences in financing arrangements that result in a higher or lower transaction price.

- ***Condition of Sale***
  Motivation of the buyer or seller that differs from the usual market conditions resulting in a sale that would not represent the market value of a property. This adjustment could be in the form of the vendor needing to make a quick sale due to a cash flow problem, a neighbouring property owner motivated to expand, or might emerge for a key property in an assembly.

- ***Expenditures Made Immediately After Purchase***
  Any expenses which a knowledgeable buyer would have considered and affected the price paid.

- ***Non-Realty Components***
  Any non-realty items such as personal property and business operations included in the sale price of the comparable.

These preceding adjustments are made before adjustment for market conditions (time).

- ***Market Conditions***
  Adjustments made for changes over time due to inflation, deflation or changes in investors' perceptions of the market. In the cases where a listing is considered it may be that a downward adjustment should be applied as typically properties sell for less than the asking price.

Following market adjustments, adjustments are made under the following main headings on a percentage or dollar basis as deemed appropriate.

- ***Location***

- ***Physical Characteristics***
  Physical differences such as site and building size, condition, accessory buildings etc.

- ***Economic Characteristics***
  Adjustments for attributes that directly affect its income. This element is usually applied to income-producing properties.

- ***Use and Zoning***
  Difference in current use potential of a comparable and the subject property.

Qualitative vs. Quantitative

Adjustments can be in the form of quantitative and/or qualitative adjustments. Quantitative adjustments may be applied as a percentage or dollar amount. Qualitative adjustments do not apply specific adjustments to sales but rather relies on comparisons. Qualitative techniques include trend analysis, relative comparison analysis and ranking analysis. In this instance we have completed a Quantitative analysis.

A survey of the local market area has been conducted and the following sales are concluded to best support value for the subject property. Detailed sales descriptions and sales location maps can be found in the Addenda of this report.

20.1 Direct Comparison Approach Table

Table 10

#	Location (Thunder Bay)	Type	Gross Floor Area (sq.ft..)	Lot Size (acres)	Coverage Ratio	Office Area	% Office	Ind Clear Height (feet)	Sale Price	Sale Price per Sq.Ft. of Building	Date for Time Adjustment	Time Adjusted Value	Time Adjusted Rate per Sq.Ft.	Adjustments Applied					Adjusted Value per sq.ft. (rounded)
S			**20,835**	**2.82**	**17%**	**8,790**	**42%**	**18-20**						**Location**	**Bldg. Size/ Scale**	**Bldg. Cond./ Quality**	**Office**	**Site size/ Coverage**	
1	1400 Walsh Street West	Industrial	10,001	3.50	7%	5,610	56%	20	$1,300,000	$130	April 30, 2020	$1,398,000	**$140**		↓	↓	↓	↓	**$101**
2	1210 Commerce Street	Industrial	6,170	2.29	6%	1,800	29%	21	$1,100,000	$178	December 18, 2020	$1,141,000	**$185**		↓	↑	↑		**$142**
3	1230 Carrick Street	Industrial	21,065	3.73	13%	5,600	27%	14-21	$1,950,000	$93	August 14, 2020	$2,063,000	**$98**	↑		↑	↑	↓	**$107**
4	605 Hewitson Street	Industrial	19,314	2.35	19%	10,080	52%	14 to 20	$2,750,000	$142	November 13, 2020	$2,868,000	**$148**	↓		↓	↓		**$124**
5	879 Tungsten Street	Industrial	16,660	1.68	23%	1,600	10%	16 to 20	$1,400,000	$84	November 1, 2018	$1,561,000	**$94**				↑	↑	**$111**
6	544 Winnipeg Avenue	Office	10,003	0.66	35%	10,003	100%	n/a	$1,200,000	$120	December 17, 2018	$1,336,000	**$134**						**$134**
7	1204 Roland Street	Office	10,128	0.98	24%	10,128	100%	n/a	$1,025,000	$101	February 19, 2019	$1,138,000	**$112**						**$112**

↑ - Inferior to Subject Property; ↓ - Superior to Subject Property; ↔ - Relatively Similar to subject property

20.2 Analysis

We have completed a thorough search for sales of similar industrial facilities throughout Thunder Bay. The subject facility is somewhat unique given its large portion of office space relative to industrial space. Sales of large industrial facilities are not common in the local market with most sales being buildings under 10,000 sq.ft.. The preceding sales Table identifies 7 sales considered useful for identifying the value potential of the subject facility. Index 1 to 5 represent industrial facilities with a mix of industrial and office space. Index 6 and 7 represent sales of office buildings to provide context relative to industrial properties. We have applied a time adjustment of 1.5% per annum to the end of 2019 and a 6% per annum adjustment for 2020 and 2021. Once adjusted the sale provide a time adjusted sale price range of $1,138,000 to $2,865,000 or $94 to $185 per sq.ft..

We have analysed the sales on a per sq.ft. basis as it is considered best reflected of the market place for this property type. The wide range in the time adjusted sales price is a result of variation in location, site size, building size, office space and building condition / quality. To better reflect the subject property, we have applied adjustments for these items where deemed appropriate. The adjustment applied for building condition / quality accounts for a range of attributes such building type, construction quality, condition, ceiling clearance, interior finish, etc..

Index 1, time adjusted to $140 per sq.ft. is the sale of a service garage situated on a large site within the subject neighbourhood. This building was formerly a Cummins sales and repair shop and was purchased for a similar use. The building is reported to have a large portion of office / showroom with 4 service bays. The purchaser appears to be an industrial user with some vehicle service needs. The site is larger while the building is overall superior but much smaller. Once adjusted this sale indicates a value of **$101 per sq.ft.**.

Index 2, time adjusted to $185 per sq.ft. is a much smaller industrial facility situated on a similar sized site. The building is a steel industrial building in modest condition. The time adjusted rate per sq.ft. is influenced by the small building size relative to the large site and as such a large downward adjustment is needed for building size / scale. This sale has been included as it is a neighbourhood sale with a similar site size/coverage. Following necessary adjustments this sale indicates a value of **$142 per sq.ft**.. Due to the much smaller building size this sale appears to be an outlier.

Index 3, time adjusted to $98 per sq.ft. is the sale of a similar sized industrial facility reported to have a large portion of office space. This building appears to be in average condition while the site provides for a large fenced yard. An upward adjustment is needed for overall building condition / quality while a downward adjustment is needed for the larger site/coverage. The location is a desirable central area but is somewhat removed at the end of Carrick Street, abutting the Needing/McIntyre floodway. Once adjusted this sale indicates a rate of **$107 per sq.ft.**.

Index 4, time adjusted to $148 per sq.ft. is the sale of two adjoining properties improved with 3 buildings. The buildings include a light industrial building with a large office section, a service shop and an office / service commercial building. The buildings ranged in condition and quality from average to good. Overall on a whole on whole comparison, this sale is considered superior to the subject property. The location has greater corner exposure and the overall building quality is superior. Once adjusted this sale indicates a rate of **$124 per sq.ft.**.

Index 5, time adjusted to $94 per sq.ft. is a large industrial facility located centrally within Thunder Bay. The building was constructed in stages over a period of roughly 20 to 30 years with the most recent addition in the 2000's. The building is reported to have been in average to good condition and included a small fenced yard. Once adjusted this sale indicates a rate of **$111 per sq.ft.**.

Index 6, time adjusted to $134 per sq.ft. and **Index 7,** time adjusted to $112 per sq.ft. represent sales of office buildings within Thunder Bay. These buildings represent entry to mid level office within industrial neighbourhoods that would be similar to the subject office space. These sales have been included to provide context and a comparison to the subject's large portion of office space. The time adjusted sale price rates of the office buildings suggest that this type of office is trading at similar values to light / service industrial buildings with only a small premium attributable to the office. We have not applied any further adjustments.

20.3 Direct Comparison Approach Conclusion

The selected comparable sales provide an adjusted range of $101 to $142 per sq.ft.. As noted, Index 2 appears to be somewhat of an outlier and is above most other available references. Excluding this sale and the office sales (Index 7 and 8) which were included to provide context, the remaining sales provide a narrowed range of $101 to $124 per sq.ft. with an average of $111 per sq.ft.. This narrowed range is considered to be a good indication of the value potential for the subject property and a conclusion within the range is considered appropriate.

Therefore, based on the available market data and the preceding analysis, we conclude a subject value of **$105 to $115 per sq.ft.** equating to a value of **$2,188,000 to $2,396,000** based on a total building size of 20,835 sq.ft..

21.0 Reconciliation and Final Estimate of Value

The following estimates have been provided in this analysis:

Cost Approach to Value	***$2,509,000***
Direct Comparison Approach	***$2,188,000 to $2,396,000***

The Cost Approach typically sets the upper limit to value and as a building ages this approach can have less reliability given the depreciation estimates applied. In this case the Cost Approach is felt to provide an upper limit to the subject property and is above the value indicated by the Direct Comparison Approach.

The Direct Comparison Approach is generally considered the most effective method of valuing a property. This is due to its close representation of market conditions for similar type properties. The Direct Comparison Approach analysis usually holds significant weight as to the value of the subject property type and in this instance offers a good indication of value.

Based on the value estimates provided, the "market value" of the property is considered to be in the range of $2,200,000 to $2,400,000 and the conclusion is the best estimate that can be reached within the range.

Based on the analysis of the available data, it is our opinion the "Market Value" of the herein described property is $2,300,000.

TWO MILLION THREE HUNDRED THOUSAND DOLLARS

Any Extraordinary Assumptions, Hypothetical Conditions and/or Extraordinary Limiting Conditions are noted in Section 6.0.

- Exposure Time

Exposure Time may be defined as: "The estimated length of time the property interest being appraised would have been offered on the market prior to the hypothetical consummation of a sale at market value on the effective date of the appraisal; a retrospective estimate based upon an analysis of past events assuming a competitive and open market." Exposure time is a function of price, time and use, not an isolated opinion of time alone. This is a retrospective estimate based upon an analysis of past events assuming a competitive and open market. It is always presumed to have preceded the effective date of the appraisal.

If competitively marketed, it is estimated that an exposure time of **6-12 months** prior to the effective date of valuation would have been required to sell the subject property at the appraised market value.

22.0 Summary of Qualifications

Peter Spivey, B.Sc., AACI, P.App

Peter Spivey obtained his honours degree in biology with a minor in geography from the University of Guelph. Upon completion of his university degree, Peter Spivey entered the appraisal field and achieved his AACI (Accredited Appraiser Canadian Institute) designation in 2009.

RELATED WORK HISTORY

2006 – Present	Andrew, Thompson and Associates Ltd.

QUALIFICATIONS

AACI	Accredited Appraiser Canadian Institute This designates a fully accredited membership in the Institute and indicates a high level of competence in a wide range of real estate appraisal.
B.Sc.	Bachelor of Science • Honours Marine and Freshwater Biology Major (University of Guelph) • Geography Minor (University of Guelph)

CERTIFICATES AND COURSES

UBC - Real Estate Appraisal Course Stream (15 Courses)

Completion of the Eco Gift Seminar

OTHER ACHIEVEMENTS

Director, Ontario Expropriation Association.

VALUATION EXPERIENCE

Land	Residential Subdivision; Industrial Subdivisions; Rights of Way; Easements; Highway Widenings; Institutional Sites; Waterfront; Recreation Lands; Agricultural, Wood Lot, Escarpment Lands, etc.
Commercial	Downtown; Strip Plaza; Special Use; Freestanding Office Buildings; Converted Dwellings; Restaurants; Service Stations, etc.
Institutional	Airports; Federal; Provincial and Municipal Assets; School Sites; Utility Easements and Right of Ways; Utility Buildings; Transportation Facilities; Landfill Sites; Transmission Tower Sites; Well and Water Tower Sites, etc.
Agricultural	Hobby Farms; Land
Unique	Large Tracts; Large Institutional Buildings; Education Development Charges.
Consulting	Expropriation; Peer Review; Education Development Charges; Alternative – Valuations
Government Consulting	Road Widening and Easement Projects; Sale of Municipal or Surplus Land; Land Acquisition; Conservation Easements, Eco Gift Valuations, Environmental Acquisition's, etc.

23.0 Assumptions, Limiting Conditions, Disclaimers and Limitations of Liabilities

The certification that appears in this report is subject to compliance with the Personal Information and Electronics Documents Act (PIPEDA), Canadian Uniform Standards of Professional Appraisal Practice ("CUSPAP") and the following conditions:

1. This report is prepared only for the client and authorized users specifically identified in this report and only for the specific use identified herein. No other person may rely on this report or any part of this report without first obtaining consent from the client and written authorization from the authors. Liability is expressly denied to any other person and, accordingly, no responsibility is accepted for any damage suffered by any other person as a result of decisions made or actions taken based on this report. Liability is expressly denied for any unauthorized user or for anyone who uses this report for any use not specifically identified in this report. Payment of the appraisal fee has no effect on liability. Reliance on this report without authorization or for an unauthorized use is unreasonable.

2. Because market conditions, including economic, social and political factors, may change rapidly and, on occasion, without warning, this report cannot be relied upon as of any date other than the effective date specified in this report unless specifically authorized by the author(s).

3. The author will not be responsible for matters of a legal nature that affect either the property being appraised or the title to it. The property is appraised on the basis of it being under responsible ownership. No registry office search has been performed and the author assumes that the title is good and marketable and free and clear of all encumbrances. Matters of a legal nature, including confirming who holds legal title to the appraised property or any portion of the appraised property, are outside the scope of work and expertise of the appraiser. Any information regarding the identity of a property's owner or identifying the property owned by the listed client and/or applicant provided by the appraiser is for informational purposes only and any reliance on such information is unreasonable. Any information provided by the appraiser does not constitute any title confirmation. Any information provided does not negate the need to retain a real estate lawyer, surveyor or other appropriate experts to verify matters of ownership and/or title.

4. Verification of compliance with governmental regulations, bylaws or statutes is outside the scope of work and expertise of the appraiser. Any information provided by the appraiser is for informational purposes only and any reliance is unreasonable. Any information provided by the appraiser does not negate the need to retain an appropriately qualified professional to determine government regulation compliance.

5. No survey of the property has been made. Any sketch in this report shows approximate dimensions and is included only to assist the reader of this report in visualizing the property. It is unreasonable to rely on this report as an alternative to a survey, and an accredited surveyor ought to be retained for such matters.

6. This report is completed on the basis that testimony or appearance in court concerning this report is not required unless specific arrangements to do so have been made beforehand. Such arrangements will include, but not necessarily be limited to: adequate time to review the report and related data, and the provision of appropriate compensation.

7. Unless otherwise stated in this report, the author has no knowledge of any hidden or unapparent conditions (including, but not limited to: its soils, physical structure, mechanical or other operating systems, foundation, etc.) of/on the subject property or of/on a neighbouring property that could affect the value of the subject property. It has been assumed that there are no such conditions. Any such conditions that were visibly apparent at the time of inspection or that became apparent during the normal research involved in completing the report have been noted in the report. This report should not be construed as an environmental audit or detailed property condition report, as such reporting is beyond the scope of this report and/or the qualifications of the author. The author makes no guarantees or warranties, express or implied, regarding the condition of the property, and will not be responsible for any such conditions that do exist or for any engineering or testing that might be required to discover whether such conditions exist. The bearing capacity of the soil is assumed to be adequate.

8. The author is not qualified to comment on detrimental environmental, chemical or biological conditions that may affect the market value of the property appraised, including but not limited to pollution or contamination of land, buildings, water, groundwater or air which may include but are not limited to moulds and mildews or the conditions that may give rise to either. Any such conditions that were visibly apparent at the time of inspection or that became apparent during the normal research involved in completing the report have been noted in the report. It is an assumption of this report that the property complies with all regulatory requirements concerning environmental, chemical and biological matters, and it is assumed that the property is free of any detrimental environmental, chemical legal and biological conditions that may affect the market value of the property appraised. If a party relying on this report requires information or an assessment of detrimental environmental, chemical or biological conditions that may impact the value conclusion herein, that party is advised to retain an expert qualified in such matters. The author expressly denies any legal liability related to the effect of detrimental environmental, chemical or biological matters on the market value of the property.

9. The analyses set out in this report relied on written and verbal information obtained from a variety of sources the author considered reliable. Unless otherwise stated herein, the author did not verify client-supplied information, which the author believed to be correct.

10. The term “inspection” refers to observation only as defined by CUSPAP and reporting of the general material finishing and conditions observed for the purposes of a standard appraisal inspection. The inspection scope of work includes the identification of marketable characteristics/amenities offered for comparison and valuation purposes only.

11. The opinions of value and other conclusions contained herein assume satisfactory completion of any work remaining to be completed in a good and workmanlike manner. Further inspection may be required to confirm completion of such work. The author has not confirmed that all mandatory building inspections have been completed to date, nor has the availability/issuance of an occupancy permit been confirmed. The author has not evaluated the quality of construction, workmanship or materials. It should be clearly understood that this visual inspection does not imply compliance with any building code requirements as this is beyond the professional expertise of the author.

12. The contents of this report are confidential and will not be disclosed by the author to any party except as provided for by the provisions of the CUSPAP and/or when properly entered into evidence of a duly qualified judicial or quasi-judicial body. The author acknowledges that the information collected herein is personal and confidential and shall not use or disclose the contents of this report except as provided for in the provisions of the CUSPAP and in accordance with the author’s privacy policy. The client agrees that in accepting this report, it shall maintain the confidentiality and privacy of any personal information contained herein and shall comply in all material respects with the contents of the author's privacy policy and in accordance with the PIPEDA.

13. The author has agreed to enter into the assignment as requested by the client named in this report for the use specified by the client, which is stated in this report. The client has agreed that the performance of this report and the format are appropriate for the intended use.

14. This report, its content and all attachments/addendums and their content are the property of the author. The client, authorized users and any appraisal facilitator are prohibited, strictly forbidden, and no permission is expressly or implicitly granted or deemed to be granted, to modify, alter, merge, publish (in whole or in part) screen scrape, database scrape, exploit, reproduce, decompile, reassemble or participate in any other activity intended to separate, collect, store, reorganize, scan, copy, manipulate electronically, digitally, manually or by any other means whatsoever this appraisal report, addendum, all attachments and the data contained within for any commercial, or other, use.

15. If transmitted electronically, this report will have been digitally signed and secured with personal passwords to lock the appraisal file. Due to the possibility of digital modification, only originally signed reports and those reports sent directly by the author can be reasonably relied upon.

16. This report form is the property of the Appraisal Institute of Canada (AIC) and for use only by AIC members in good standing. Use by any other person is a violation of AIC copyright.

17. Where the intended use of this report is for financing or mortgage lending or mortgage insurance, it is a condition of reliance on this report that the authorized user has or will conduct lending, underwriting and insurance underwriting and rigorous due diligence in accordance with the standards of a reasonable and prudent lender or insurer, including but not limited to ensuring the borrower's demonstrated willingness and capacity to service his/her debt obligations on a timely basis, and to conduct loan underwriting or insuring due diligence similar to the standards set out by the Office of the Superintendent of Financial Institutions (OSFI), even when not otherwise required by law. Liability is expressly denied to those that do not meet this condition. Any reliance on this report without satisfaction of this condition is unreasonable.

18. All copyright is reserved to the author and this report is considered confidential by the author and the client. Possession of this report, or a copy thereof, does not carry with it the right to reproduction or publication in any manner, in whole or in part, nor may it be disclosed, quoted from or referred to in any manner, in whole or in part, without prior written consent and approval of the author as to the purpose, form and content of any such disclosure, quotation or reference. Without limiting the generality of the foregoing, neither all nor any part of the contents of this report shall be disseminated or otherwise conveyed to the public in any manner whatsoever or through any media whatsoever or disclosed, quoted from or referred to in any report, financial statement, prospectus, or offering memorandum of the client, or in any documents filed with any governmental agency without the prior written consent and approval of the author as to the purpose, form and content of such dissemination, disclosure, quotation or reference. This is subject only to confidential review by the Appraisal Institute of Canada as provided in the Canadian Uniform Standards of Professional Appraisal Practice.

24.0 Certification

I certify that, to the best of my knowledge and belief that:

1. The statements of fact contained in this report are true and correct;
2. The reported analyses, opinions and conclusions are limited only by the reported assumptions and limiting conditions and are my impartial and unbiased professional analyses, opinions and conclusions;
3. I have no past, present or prospective interest in the property that is the subject of this report and no personal and/or professional interest or conflict with respect to the parties involved with this assignment.
4. I have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment;
5. My engagement in and compensation is not contingent upon developing or reporting predetermined results, the amount of value estimate, a conclusion favouring the client, or the occurrence of a subsequent event.
6. My analyses, opinions and conclusions were developed, and this report has been prepared, in conformity with the CUSPAP.
7. I have the knowledge and experience to complete this assignment competently, and where applicable this report is co-signed in compliance with CUSPAP;
8. Except as herein disclosed, no one has provided significant professional assistance to the person(s) signing this report;
9. As of the date of this report the undersigned has fulfilled the requirements of the AIC's Continuing Professional Development Program;
10. The undersigned is (are all) members in good standing of the Appraisal Institute of Canada.

Property Identification

Address:	680 Beaverhall Place, Thunder Bay, ON
Legal Description:	Lot 13, Plan W796, (Neebing), City of Thunder Bay

Based upon the data, analyses and conclusions contained herein, the Market Value of the interest in the property described:

As at July 28, 2021 is estimated at $2,300,000 (amount in Canadian dollars).

Any Extraordinary Assumptions, Hypothetical Conditions and/or Extraordinary Limiting Conditions are noted in Section 6.0.

As set out elsewhere in this report, this report is subject to certain assumptions and limiting conditions, the verification of which is outside the scope of this report.

Appraisal Institute of Canada Appraiser

Signature: DRAFT
Name: Peter Spivey, B.Sc, AACI, P.App, 904444
Date of Report:
Personally, Inspected the Subject Property Yes
Date of Inspection: July 28, 2021
Source of digital signature security: Password Protected PDF Document
Note: For this appraisal to be valid, an original or a digital signature is required and the document is to be password protected from modification.

Attachments and Addenda Items:

- Parcel Register
- Detailed Land Comparable Sales and Sales Location Maps
- Detailed Improved Comparable Sales and Sales Location Maps

25.0 Addenda

25.1 Parcel Register
25.2 Detailed Comparable Land Sales and Sales Location Maps
25. 3 Detailed Comparable Sales and Sales Location Maps

25.1 Parcel Register

Ontario ServiceOntario

LAND REGISTRY OFFICE #55

PARCEL REGISTER (ABBREVIATED) FOR PROPERTY IDENTIFIER

62043-0045 (LT)

* CERTIFIED IN ACCORDANCE WITH THE LAND TITLES ACT * SUBJECT TO RESERVATIONS IN CROWN GRANT *

PAGE 1 OF 1
PREPARED FOR aicSThomp7
ON 2021/08/16 AT 14:19:56

GEOWAREHOUSE

PROPERTY DESCRIPTION: LT 13 PL W796 NEEBING; THUNDER BAY

PROPERTY REMARKS:

ESTATE/QUALIFIER:
FEE SIMPLE
LT CONVERSION QUALIFIED

RECENTLY:
FIRST CONVERSION FROM BOOK

PIN CREATION DATE:
2004/03/29

OWNERS' NAMES
ONTARIO HYDRO

CAPACITY SHARE
BENO

REG. NUM.	DATE	INSTRUMENT TYPE	AMOUNT	PARTIES FROM	PARTIES TO	CERT/ CHKD
** PRINTOUT INCLUDES ALL DOCUMENT TYPES AND DELETED INSTRUMENTS SINCE 2004/03/26 **						
**SUBJECT, ON FIRST REGISTRATION UNDER THE LAND TITLES ACT, TO:						
** SUBSECTION 44(1) OF THE LAND TITLES ACT, EXCEPT PARAGRAPH 11, PARAGRAPH 14, PROVINCIAL SUCCESSION DUTIES *						
** AND ESCHEATS OR FORFEITURE TO THE CROWN.						
** THE RIGHTS OF ANY PERSON WHO WOULD, BUT FOR THE LAND TITLES ACT, BE ENTITLED TO THE LAND OR ANY PART OF						
** IT THROUGH LENGTH OF ADVERSE POSSESSION, PRESCRIPTION, MISDESCRIPTION OR BOUNDARIES SETTLED BY						
** CONVENTION.						
** ANY LEASE TO WHICH THE SUBSECTION 70(2) OF THE REGISTRY ACT APPLIES.						
**DATE OF CONVERSION TO LAND TITLES: 2004/03/29 **						
OFW50314	1965/05/07	ORDER IN COUNCIL				C
REMARKS: AMENDS LAKEHEAD AIRPORT ZONING REGULATIONS * DOCUMENT TYPE CHANGED FROM BYLAW TO ORDER-IN-COUNCIL ON JANUARY 16, 2007 W.LITTLE *						
OFW68098	1970/07/22	BYLAW				C
TBR253659	1984/03/09	ASSIGNMENT LEASE			GUARANTY TRUST CO. OF CANADA CAPITAL EQUIPMENT INC.	C
TBR299917	1988/09/26	TRANSFER	$525,000		ONTARIO HYDRO	C

NOTE: ADJOINING PROPERTIES SHOULD BE INVESTIGATED TO ASCERTAIN DESCRIPTIVE INCONSISTENCIES, IF ANY, WITH DESCRIPTION REPRESENTED FOR THIS PROPERTY.
NOTE: ENSURE THAT YOUR PRINTOUT STATES THE TOTAL NUMBER OF PAGES AND THAT YOU HAVE PICKED THEM ALL UP.
NOTE: RESULTS WERE GENERATED VIA WWW.GEOWAREHOUSE.CA

25.2 Detailed Land Sales and Land Sales Location Maps

COMPARABLE#: 1

Address:	645 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$325,000.00
Sale $/Unit:	$179,558 per acre
Sale Date:	Nov 26, 2020
Pin #	620430091
Vendor	948825 Ontario Inc.
Purchaser	Sparcon Construction Inc.
Roll Number	580404020102500

SITE INFORMATION

Lot Area:	1.81	acres	**Frontage:**	322	**Zoning**	IN2- Medium Industrial
Location:	Interior		**Services:**	Full	**OP:**	Industrial

Legal Description Lot 17 Plan W796,Neebing; City of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 2

Address:	600 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$250,000.00
Sale $/Unit:	$160,256 per acre
Sale Date:	Dec 04, 2020
Pin #	620430043
Vendor	Pepco Tbay Inc.
Purchaser	2786341 Ontario Ltd.
Roll Number	580404020103900

SITE INFORMATION

Lot Area:	1.56	acres	**Frontage:**	170	**Zoning**	ID2- Medium Industrial
Location:	Corner		**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 6 on Plan W796, Neebing Part 1, 55R10259; in the city of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is located at the intersection of Beaverhall Place and Mountdaye Avenue. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 3

Address:	685 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$300,000.00
Sale $/Unit:	$348,837 per acre
Sale Date:	Jun 25, 2021
Pin #	620430053
Vendor	Grant Equipment Corp.
Purchaser	539804 Ontario Inc.
Roll Number	580404020113105

SITE INFORMATION

Lot Area:	0.86 acres	**Frontage:**	127	**Zoning**	IN1- Light Industrial
Location:	Interior	**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 20 on Plan W796, Neebing; Part Stanley Ave. on Plan QW796 Neebing, Closed by TBR413183, Part 1 and 2 on 55R7794; Subject to Right in TBR221127; in the city of Thunder Bay

Parcel of a small parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site was reportedly acquired by a nearby user to develop an industrial facility. This site was cleared and generally level and used as a storage yard at the time of the sale. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 4

Address:	625	Mountdale Ave.
Municipality:	Thunder Bay	
Community:	n/a	
Sale Price:	$167,000.00	
Sale $/Unit:	$115,172 per acre	
Sale Date:	May 04, 2016	
Pin #	620430089	
Vendor	Not Available	
Purchaser	Mahon Electric Company Limitedà	
Roll Number	580404020104000	

SITE INFORMATION

Lot Area:	1.45 acres	**Frontage:**	244	**Zoning**	ID2- Medium Industrial
Location:	Interior	**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 7 on Plan W796, Neebing, Parts 1 and 2 on Plan 55R14039, Subject to an Easement in Gross over Part 2 on Plan 55R14039 as in TY214023, in the city of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area), fronting the west side of Mountdale Avenue. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 5

Address:	625	Beaverhall Place
Municipality:	Thunder Bay	
Community:	n/a	
Sale Price:	$300,000.00	
Sale $/Unit:	$177,515 per acre	
Sale Date:	Sep 09, 2014	
Pin #	620430049	
Vendor	Royal Host GP Inc.	
Purchaser	1383793 Ontario Inc.	
Roll Number	580404020102600	

SITE INFORMATION

Lot Area:	1.69 acres	**Frontage:**	300	**Zoning**	C3- Highway Com.
Location:	Interior	**Services:**	Full	**OP:**	Commercial

Legal Description Part of Lot 16 on Plan W796 Neebing as in TBR341227 as ammended by TBR394415 except the Easement therein; Part of Block A on Plan 864 Neebing, Part 1 and 2 on 55R8957; Subject to TBR341227 and OFW54411; in the city of Thunder Bay

Parcel of commercial designated land located in a primarily industrial area known as the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is located adjoining an older motel and formerly formed part of the parking lot. Although designated commercial some opportunity may be present for conversion to an industrial type use. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 6

Address: 295 Court Street S.
Municipality: Thunder Bay
Community: n/a
Sale Price: $1,150,000.00
Sale $/Unit: $330,460 per acre
Sale Date: Jul 30, 2021
Pin # 621260078 & 621260074
Vendor Arnone Transport Limited
Purchaser Not Yet Registered
Roll Number 580401003503600 & *

SITE INFORMATION

Lot Area: 3.48 acres **Frontage:** 409 **Zoning:** IN2- Medium Com.
Location: Interior **Services:** Full **OP:** Industrial

Legal Description Part Lot 1-4 Block 35on Plan 147 McIntyre; Part Lot 49-51, 54-55, 57 Plan 572 McIntyre Part 3 & 4, 55R10246; T/W TBR413511; Subject to PTA141390; Subject toTBR284105, TBR398827; in the city of Thunder Bay & **

Sale of a good quality parcel of employment land located centrally in Thunder Bay. This site had exposure to Water Street, a 4 lane arterial road and is on the fringe of the downtown core. The site is cleared and generally level and appears to have been utilized for trailer parking / storage.

MLS Sale Date: 06/25/2021

* 580401003500910
**Lots 73,75,77,79 & Part of Lots 54,56,58,80,81,82 & Part Inchiquin Street Closed by TBR163865, on Plan 572 AND Part Lots 2,3,4 & Part Lane Closed by TBR163865 & Part 0.30 Reserve Block 35 on Plan 147 Being Parts 1 & 5 55R12031 & Parts 7 & 8 55R10246 ; Thunder Bay ; Subject to Easements TBR438725,F128620,F132236 on Part 5 Plan 55R12031; in the city of Thunder Bay.

COMPARABLE#: 7

Address: 0 Dunlop Street

Municipality: Thunder Bay

Community: n/a

Sale Price: $151,000.00

Sale $/Unit: $138,532 per acre

Sale Date: Mar 18, 2021

Pin # 620790552 & 620790507

Vendor Not Available

Purchaser 1648822 Ontario Ltd.

Roll Number 580401003732800

SITE INFORMATION

Lot Area: 1.09 acres **Frontage:** 200 **Zoning** IN2- Medium Ind.

Location: Interior **Services:** Full **OP:** Commercial

Legal Description Lots 132-136 on Plan M52 and Part Brandon Avenue, Plan M52 Closed by LT136601, Part 5 on 55R14780; in the city of Thunder Bay & Part Brandon Avenue on Plan M52 Closed by LT136601, Part 4 on 55R14780; in the city of Thunder Bay

Small parcel of industrial land located centrally within Thunder Bay. This site was treed and required clearing and some fill to allow for development.

COMPARABLE#: 8

Address:	224 Burwood Rd
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$399,900.00
Sale $/Unit:	$141,307 per acre
Sale Date:	Jan 15, 2020
Pin #	621170020
Vendor	Daniel Clara
Purchaser	Reliable Northern Developments Ltd.
Roll Number	580402010108000

SITE INFORMATION

Lot Area:	2.83	acres	**Frontage:**	248	**Zoning**	IN6- Prestige Ind.
Location:	Interior		**Services:**	Full in Area	**OP:**	Industrial

Legal Description Part of Lot 19 on Plan 760 McIntyre as in TBR215580; city of Thunder Bay

Parcel of industrial land located in the central portion of Thunder Bay, slightly east of Highway 17. The site was forested and required clearing and some grading / fill works. It is our understanding that full municipal services are in the area.

Land Sales Location Maps

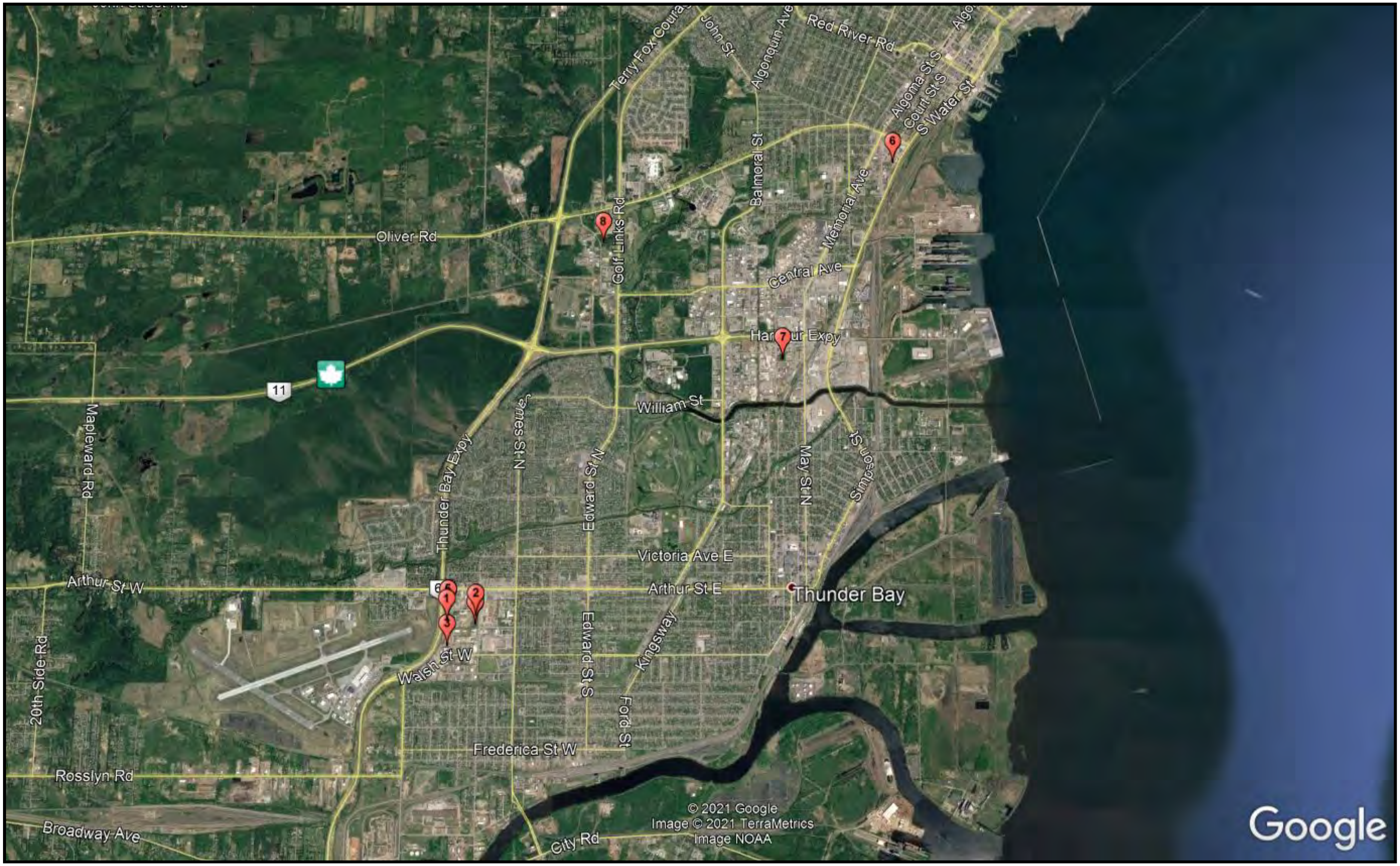


Figure 14 Source: Google Earth

Figure 15 Source: Google Earth

25.3 Detailed Comparable Sales and Sales Location Maps

COMPARABLE#: 1

Service Industrial

Address:	1400 Walsh St. West
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$1,300,000.00
Sale $/Unit:	$ 130 / sq. ft.
Sale Date:	Apr 30, 2021
Pin #	620420023 & 620420022
Vendor	4249739 Canada Inc.
Purchaser	Wildon Wiring Limited
Roll Number	580404020116400

SITE INFORMATION

Lot Area:	3.50 acres	**Services:**	Full
Location:	Corner	**Type:**	IND
Surplus Land:	Yes	**Prop Code:**	540
Zoning:	Med. Industrial		
Zoning OP:	Industrial		

BUILDING INFORMATION

Area:	10,001 sq.ft.
Age:	1973
Units:	1

Sale of a former Cummings sales and service facility that is now utilized by an industrial user as a service shop. The property included a large yard area. The building appears to be in average to good condition with a reported 5,610 sq.ft. of office / showroom area.

COMPARABLE#: 2

Industrial

Address: 1210 Commerce Street

Municipality: Thunder Bay

Community: n/a

Sale Price: $1,100,000.00

Sale $/Unit: $178/ sq. ft

Sale Date: Dec 18, 2020

Pin # 6204020012 & 620420008 *

Vendor Wildon Wiring Limited

Purchaser Emcon Services Inc.

Roll Number 580404020117110 & **

SITE INFORMATION

Lot Area: 2.29 acres

Services: Full

Location: Interior

Type: IND

Surplus Land: Yes

Prop Code: 540

Zoning: Med. Industrial

Zoning OP: Industrial

BUILDING INFORMATION

Area: 6,170 sq.ft.

Age: 1978

Units: 1

Sale of an industrial property improved with a roughly 6,100 sq.ft. industrial building situated on 2.29 acre site. The building is reported to include 1,800 sq.ft. of office, 3,600 sq.ft. of service industrial area and 970 sq.ft. of storage space with lower ceilings. The building is a steel building that appears to be in modest to average condition. The site provides for a large fenced gravel yard.

*620420007, 620420008, 620420009, 620420012
** 580404020116700

We note that the property sold on MLS in August 2020 for a price of $849,000. This transaction does not appear to have closed and the property resold as outlined in December 2020.

COMPARABLE#: 3

Industrial

Address: 1230 Carrick Street

Municipality: Thunder Bay

Community: n/a

Sale Price: $1,950,000.00

Sale $/Unit: $93 / sq. ft

Sale Date: Aug 14, 2020

Pin # 620790071 & 620790072

Vendor 1876009 Ontario Inc.

Purchaser Trevlind Investments Limited

Roll Number 580401003787900 & *

SITE INFORMATION

Lot Area: 3.73 acres

Location: Interior

Surplus Land: Yes

Zoning: Medium Indus trial

Zoning OP: Industrial

Services: Full

Type: IND

Prop Code: 520

BUILDING INFORMATION

Area: 21,065 sq.ft.

Age: n/a

Units:

The property was improved with an older industrial building that appears to be in average condition. The reported size was approximately 21,065 sq.ft.. along with an estimated office area of 5,600 sq.ft. +/-. Also noted was a separate small cold storage building. The site includes a large fenced yard. With regard to location, the property is situated in a desirable general area, i.e. Intercity, but is only fair with respect to its specific setting recognizing its somewhat removed location at the end of Carrick Street abutting the Neebing/McIntyre floodway.

* 580401003787900

COMPARABLE#: 4

Industrial

Address: 605 Hewitson Street

Municipality: Thunder Bay

Community: n/a

Sale Price: $2,750,000.00

Sale $/Unit: $142 / sq.ft.

Sale Date: Jan 06, 2021

Pin # 6207900013 & 620790014

Vendor DST Technologies Inc.

Purchaser 1401285 Ontario Inc.

Roll Number 58040003788315

SITE INFORMATION

Lot Area:	2.35	acres	**Services:**	Full
Location:	Corner		**Type:**	IND
Surplus Land:	No		**Prop Code:**	520
Zoning:	Light Ind.			
Zoning OP:	Industrial			

BUILDING INFORMATION

Area:	19,314	sq.ft
Age:	n/a	
Units:	3	

Sale of two adjoining properties improved with a total of 3 buildings. The bindings have a total area of approximately 19,310 sq.ft. and include two steep clad industrial buildings and a brick and siding clad service commercial / office building. The steel buildings appear to be in average condition while the brick clad building appears to be in good condition. Some of the buildings appeared to be tenanted at the time of the sale. The site provide for a paved parking area and a gravel yard area.

MLS sale Date: Nov 13, 2020

COMPARABLE#: 5

Industrial

Address:	879 Tungsten Street
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$1,400,000.00
Sale $/Unit:	$84 / sq.ft.
Sale Date:	Nov 01, 2018
Pin #	621220254 621220255
Vendor	2017506 Ontario Ltd.
Purchaser	LW Holdings Ltd.
Roll Number	580401003231600

SITE INFORMATION

Lot Area:	1.68 acres	**Services:**	Full
Location:	Interior	**Type:**	IND
Surplus Land:	No	**Prop Code:**	520
Zoning:	Medium Ind.		
Zoning OP:	Industrial		

BUILDING INFORMATION

Area:	16,600 sq.ft.
Age:	n/a
Units:	1

Sale of an approximately 16,660 sq.ft. one-storey non-clear span industrial building. It was originally developed for use in conjunction with a retail lumber yard, circa late 1980s/early 1990s. The building was constructed in stages with the current building representing essentially an open shell with concrete floors and painted drywall walls & ceilings that is reported to be in good overall condition. The presence of attractive main floor office space of approx. 1600 sq.ft., with a similar amount of 2nd floor partially finished mezzanine for use as storage and an employees' lunchroom is reported. The site includes a fenced side yard and rear yard area.

COMPARABLE#: 6

Office

Address: 544 Winnipeg Ave.

Municipality: Thunder Bay

Community: n/a

Sale Price: $1,200,000.00

Sale $/Unit: $120 / sq. ft.

Sale Date: Dec 17, 2018

Pin # 621220164 621220165 621220166 ° *

Vendor Sandpaul Investments Limited

Purchaser 1778705 Ontario Ltd.

Roll Number 580401003625700

SITE INFORMATION

Lot Area: 0.66 acres

Services: Full

Location: Interior

Type: OFF

Surplus Land: No

Prop Code: 400

Zoning: C4-A

Zoning OP: Commercial

BUILDING INFORMATION

Area: 10,003 sq.ft.

Age: n/a

Units: 1

Sale of an entry level office building that appears to be utilized by a community group. The building is a single storey steel and brick clad structure that appears to be in average condition. The site provides paved parking on the north and south side of the building. The property is located near Memorial Ave, a busy arterial road.

* 621220167

COMPARABLE#: 7

Office

Address:	1204 Roland Street
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$1,025,000.00
Sale $/Unit:	$101/ sq. ft.
Sale Date:	Feb 19, 2019
Pin #	620790024
Vendor	1526454 Ontari Limited
Purchaser	1526152 Ontario Inc.
Roll Number	580401003751500

SITE INFORMATION

Lot Area:	0.98	acres	**Services:**	Full
Location:	Corner		**Type:**	OFF
Surplus Land:	No		**Prop Code:**	402
Zoning:	Light Ind.			
Zoning OP:	Industrial			

BUILDING INFORMATION

Area:	10,128	sq.ft.
Age:	1976	
Units:	3	

Sale of a multi-tenant office building located at the intersection of Roland Street and Balmoral Street. This building has a decorative concrete block construction, built in the 1970's. The site provides a paved parking lot. Overall the property and building appears to be in average condition.

Sales Location Maps

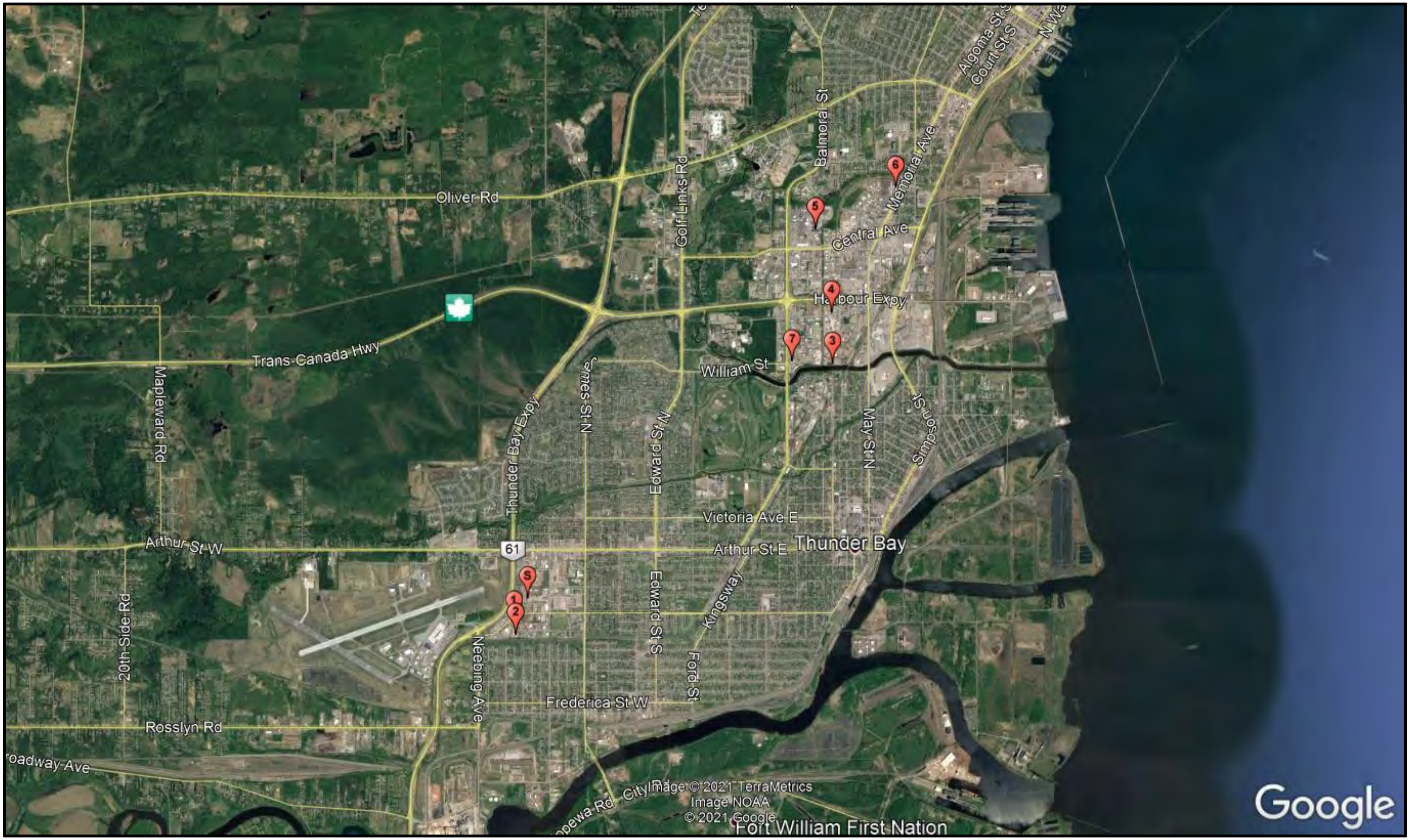


Figure 16 Source: Google Earth

Figure 17 Source: Google Earth

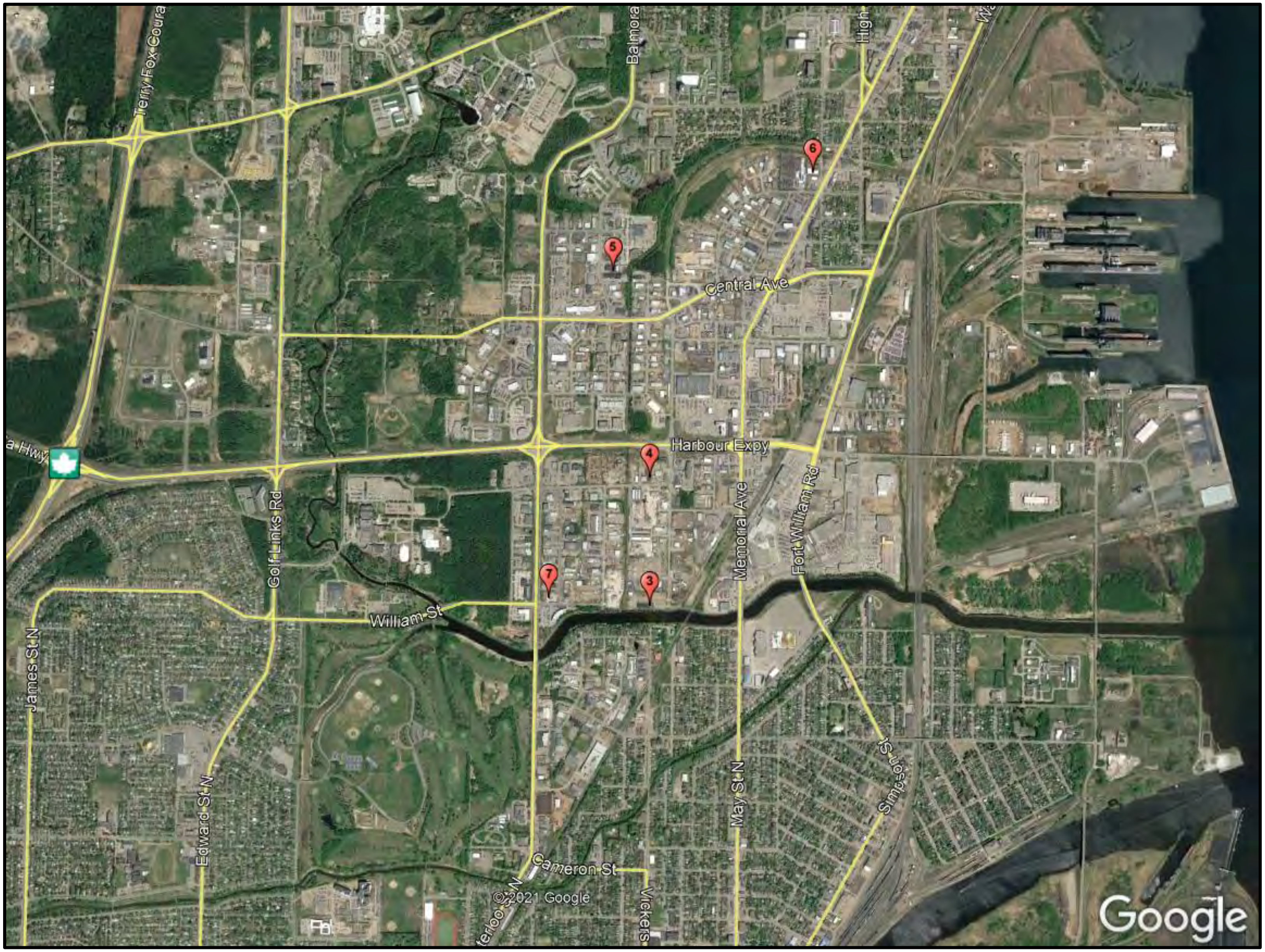


Figure 18 Source: Google Earth

ATTACHMENT 4:

REPORT OF ALTERNATE BUILDING / SITE OPPORTUNITIES

CONSULTING REPORT OF

Hydro One Remote Communities Inc.
Alternate Building / Site Opportunities
Thunder Bay, ON

PREPARED FOR

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

ANDREW, THOMPSON
& ASSOCIATES LTD.

177 Dunlop Street West
Barrie, ON L4N 1B4
PHONE 705-721-1596 FAX 705-721-5183
WEB www.andrew-thompson.on.ca

ATA Real Estate Advisors

August 17, 2021

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

Attention: Mr. Keith Barr

Re: HONI Remote Communities - Alternate Building / Site Opportunities

Dear Mr. Barr:

Further to your request, we provide this consulting report addressing the site / building availability search for a new Hydro One Remote Communities facility in the Thunder Bay Market. We have thoroughly considered your requirements as outlined in the RFP. This report has been prepared based on our understanding of the identified criteria.

Further to your instructions, we have conducted a market investigation for properties available or suitable for the acquisition and development of a new Hydro One Remote Communities facility. The alternatives are based on a variety of site / building criteria within the provided geographic boundaries identified within the RFP.

We do not have any conflicts of interest to disclose which emerged from the work completed to date.

This consulting report is intended to be consistent with the Terms of Reference and in accordance with the Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) adopted by the Appraisal Institute of Canada.

.

TABLE OF CONTENTS

1.0 Study Framework

Hydro One Remote Communities Inc. (herein referred to as Remotes) is searching for an alternate location to establish a new facility to replace the existing facility found at 680 Beaverhall Place, Thunder Bay. This market investigation identifies properties available for the acquisition and development of a facility or an existing facility based on a variety of site criteria within a pre-selected geographic boundary.

The current facility at 680 Beaverhall Place, City of Thunder Bay, which provides for administrative, shop, warehouse and outdoor storage functions is no longer considered suitable to meet Remotes operational requirements and this site / building opportunity study is in support of the search for a property to develop a new facility.

We have been requested to address the following items with this study:

1. Available sites for a new development opportunity.
2. Available existing facilities.
3. Benchmark land value within the immediate neighbourhood proximity of the existing facility at 680 Beaverhall Place.

1.1 General Site Requirement Characteristics

The client has provided the following general guidelines with regard to an existing / development opportunity.

> *With the high dependency of the operations for flight support, the preferred siting of a new Operations Centre would be in close proximity to the Thunder Bay International Airport (the "Airport"). This spatial relationship does not have an absolute requirement, such as time and distance, but preference would be given to equivalent properties / developments that optimize this relationship.*
>
> *As to physical siting in proximity to the Airport, there are no operational activities of concern. As an example, the Operations Centre does not include or use high mast structures or cranes as part of its development and operations, which would be restricted within flight path corridors.*

1.2 Geographic Boundaries

Generally, the study area is to be within a 5 km distance from the Thunder Bay International Airport. Our research has been expanded to include the entire City of Thunder Bay and the immediate surrounding areas.

1.3 Essential Site Criteria

The following outlines the provided ideal criteria:

- Site area of no less than 5 acres.
- Full municipal services, including water, sanitary, gas, hydro and

telecommunications.
- Convenient access to major transportation routes.
- Less than 5 kilometers to the Thunder Bay International Airport.
- Permit a building program of up to 30,000 square feet.
- Building program reflecting flex-industrial space to accommodate the aforementioned space requirements.
- Parking for 40+ staff and visitors.
- Proximity to hotels and food services, less than 5 kilometers.

1.4 Essential Building Criteria – Existing Facility

The client has not provided specific building criteria for existing facilities to be considered. We have been provided with a preliminary list of upgrade requirements relative to the existing facility and we have discussed the needs with Mr. Barr. Based on these guidelines we have completed a search for existing facilities.

2.0 Basis of the Report

Client – The Client for this file is Hydro One Remote Communities Inc

The Intended User(s) - This report is intended for use only by Hydro One Remote Communities Inc

Purpose / Intended Use of the Report - The purpose / intended use of this consulting report is to assist with determining available development opportunities in the Thunder Bay Market.

We have not applied a Jurisdictional Exception in the preparation of this report.

2.1 Terms of Reference

At the request of The Hydro One Remotes Communities Inc., Andrew, Thompson & Associates Ltd. was instructed to:

- Identify available sites that meet the provided criteria.
- Identify available existing facilities that would suit Remotes needs.
- Provide a benchmark land value for sites within the immediate neighbourhood/ proximity of the existing facility at 680 Beaverhall Place.

2.2 Extraordinary Assumptions, Hypothetical Conditions and Limiting Conditions

Extraordinary Assumptions

An extraordinary assumption refers to an assumption, directly related to a specific assignment, which, if found to be false, could materially alter the opinions or conclusions.

- We note that all referenced sites are assumed to be free of contamination unless otherwise noted.

Hypothetical Conditions

A hypothetical condition is that which is contrary to what exists, but is supposed to exist for the purpose of analysis.

- None

Extraordinary Limiting Condition

An extraordinary condition is a necessary modification or exclusion of a Standard Rule which may diminish the reliability of the report.

- As of the date of this report Canada and the Global Community is experiencing unprecedented measures undertaken by various levels of government to curtail health related impacts of the Covid-19 Pandemic. The duration of this event is not known. While there is potential for impacts with respect to micro and macro-economic sectors, as well as upon various real estate markets, it is not possible to predict such impact at present, or the impact of current and future government countermeasures. Accordingly, this point-in-time valuation assumes the continuation of current market conditions, and that current longer-term market conditions remain unchanged. Given the market uncertainties of the Covid-19 pandemic, a force majeure event, we reserve the right to revise the value estimation set out in this report for a fee, with an update appraisal report under a separate appraisal engagement, incorporating market information available at that time. Values contained in this appraisal are based on market conditions as at the time of this report. This appraisal does not provide a prediction of future values. In the event of market instability and/or disruption, values may change rapidly and such potential future events have NOT been considered in this report. As this appraisal does not and cannot consider any changes to the property appraised or market conditions after the effective date, readers are cautioned in relying on the appraisal after the effective date noted herein.

3.0 Scope Of Work Undertaken

We have reviewed the identified market area to determine vacant sites and available facilities that meet the requirements identified. This review included:

- Review of prevailing MLS activity for the market area.
- Review of major commercial brokerage listings.
- Review / contact the City of Thunder Bay and Economic Development Department / Real Estate Department regarding available municipal properties.
- Contacted active commercial real estate professionals including brokers and appraisers.
- Contacted local developers active in industrial development.
- On-ground observations.

The analysis set out in this report relied upon written and verbal information obtained from a variety of sources considered reliable. Unless otherwise stated we did not verify client-supplied information, which we believed to be correct.

The work required conversations with Municipal departments as well interviews with owners, agents and developers in order to identify opportunities in the identified market area. All discussions were conducted with the strictest measures of confidentiality.

Excluded Item(s) of Review

The following technical investigations **were not completed**:

- An environmental review or study of the site alternatives, including a historical use analysis;
- Investigation into bearing qualities of the soils;
- Subsurface qualities of the soil; percolation or other soil qualities; or;
- An archaeological review.

We note that all referenced sites are assumed to be free of contamination unless otherwise noted.

4.0 Consulting Framework

4.1 Report Format

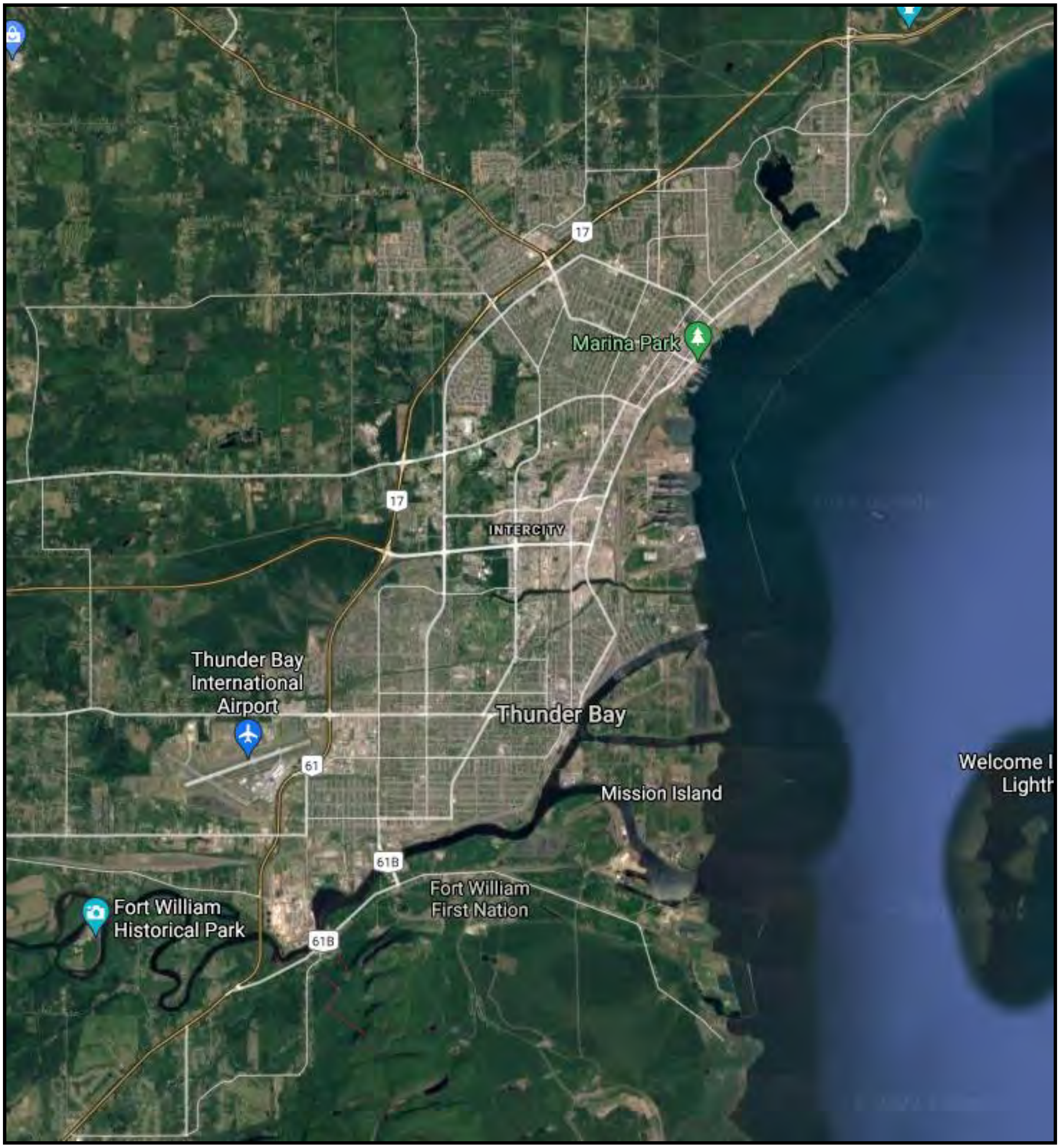
The Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) outlines the standard rules as it relates to the development and communication of a formal opinion of value and identifies the minimum content necessary to produce a credible report that is not misleading. The following reporting formats are available to the appraiser:

> ***Consulting*** - The development and communication of a real property consulting service must incorporate the minimum content necessary to produce a credible result that is not misleading.
>
> ***Current Value*** – refers to an effective date contemporaneous with the date of the report, at the time of inspection or at some other date within a reasonably short period from the date of inspection when market conditions have not or are not expected to have changed.

This current consulting report is provided with regard to the rules and regulations as outlined in CUSPAP.

5.0 Market Overview

5.1 Thunder Bay – General Overview



Positioned on the western shore of Lake Superior, the City of Thunder Bay is the central urban focus for Northwestern Ontario. It is the predominant urban centre for supply and service to a region that extends west for 375 miles (600 kilometres) to the Province of Manitoba; east for 250 miles (400 kilometres) to the District of Algoma, Ontario; and north for varied and considerable distances by road or air to several small communities and a number of remote access First Nation Reserves.

The economy of Thunder Bay was founded around being the most western Canadian terminus of the Great Lakes and St. Lawrence Seaway system, as well as the harvest and process of natural resources (timber and minerals) from a vast and surrounding hinterland region. This economy has been in transition since the late 1970's, with reduced use of waterway transportation and significant but variable changes in the nature of mining and forestry.

Over the past 40 years, changes in mining and forestry have had a more noticeable impact on the surrounding region of Northwestern Ontario. However, they have also caused changes in the nature of employment and business in Thunder Bay. Since the 1970's, the Thunder Bay economy has undergone a slow and occasionally painful transition from transportation and resource harvest and production, to regional service and supply.

Changes in Thunder Bay Population

Referencing information published by Statistics Canada, population changes for Thunder Bay and its surrounding Census Metropolitan Area are tracked as follows.

The Thunder Bay CMA extends east from the City Limits to include the adjoining rural Municipality of Shuniah, and west to include the rural Municipality of Oliver-Paipoonge and the rural Townships of O'Connor, Marks and Conmee. It extends north and northwest to include the rural Townships of Gorham and Ware, Jacques, Fowler and Dawson Road Lots. It extends south and southwest to include the rural Township of Gillies and the Municipality of Neebing.

Table 1

	Thunder Bay City	Thunder Bay CMA
Census Year 2001	109,016	121,986
Census Year 2006	109,140	122,907
Census Year 2011	108,359	121,596
Census Year 2016	107,909	121,621

The population of both the City of Thunder Bay and the Thunder Bay CMA have remained stable from 2001 to the most recent Census in 2016, with no population growth observed.

EXHIBIT 31 – POPULATION PROJECTIONS

Scenario	2016 (Census)	2019 (forecast)	2051 (forecast)	Change (2019-2051)
Base Case	107,810	108,935	124,241	15,306
Low Case	107,810	108,122	113,863	5,741
High Case	107,810	109,751	135,535	25,784
High+ Case	107,810	109,751	155,802	46,051

Figure 1: Employment Land Strategy 2020

5.2 ICI Land Supply & Demand

The City of Thunder Bay undertook an Employment Land Strategy Study in 2020. This study was completed by Cushman & Wakefield. The following represent excerpts from the Cushman & Wakefield an Employment Land Strategy Study 2020 dated September 30, 2020.

Land Demand

The employment by industry projection can be translated into a forecast of land needs by identifying the type of buildings that are required for each category of employment. The following highlights the conclusions of our land demand analysis.

Industrial – Using a benchmark industrial employment density and a typical industrial building site coverage ratio, there is demand for approximately 30 gross hectares of industrial land through the 2051 forecast horizon.

Office – Guided by recent office development formats in the city, employment in sectors that are associated with office-type space demand is anticipated to generate demand for 7 gross hectares for office uses by 2051.

Institutional – In discussion with the city's largest institutional employers, there is no identified near or medium-term requirement for additional Institutional-designated lands. Large institutional sites/campuses all offer excess lands that can accommodate future development, and on-site intensification is their principal focus of growth.

Retail-Commercial – The Consultant Team prepared two retail-commercial land demand scenarios that are guided by the same population forecast, but different assumptions about the amount of retail space demanded per capita. New retail-commercial uses will continue to emerge, and it is highly likely that some buildings within the existing inventory will become obsolete, and repurposed to a mixed-use or other form of redevelopment. It is recommended that the City plan for 25 gross hectares of retail-commercial land through 2051.

Our analysis has identified a considerable supply of vacant, designated employment lands in the City of Thunder Bay. The demand assessment indicates that future employment land requirements can be accommodated on existing sites. Therefore, there is no identified need to consider the conversion of any non-employment lands for employment purposes.

Land Supply

At an aggregate level, there is a vast supply of remaining undeveloped, designated industrial lands across Thunder Bay. This is particularly the case for Light Industrial-designated sites (520 vacant hectares) and Heavy Industrial-designated sites (over 200 vacant hectares), but the comment is also applicable to lands designated as Business Area (nearly 50 vacant hectares). Notably, this analysis does not even factor in existing occupied lands which may represent opportunities *for intensification, or potentially redevelopment. A legacy of contamination of lands and buildings is a challenge in Thunder Bay on certain sites where there is a history of heavy industrial activity. Further, there are serviced employment lands at Thunder Bay International Airport that are suitable for industrial development – although these lands are not available for acquisition; these would be subject to a land lease arrangement.*

While there are large concentrations of both Light Industrial and Heavy Industrial-designated vacant lands in areas on the city's periphery (including Mission and McKellar Islands), site visits by the Consultant Team have revealed a relative scarcity of vacant industrial lands in some of the more centrally-situated existing (built-up) employment areas. Of note, Innova Business Park represents a sizable inventory of remaining undeveloped lands that are centrally located, and more proximate to labour compared to other undeveloped planned industrial areas. Accordingly, the Light Industrial and Business Area lands located in Innova Business Park and to the north along Thunder Bay Expressway, Burwood Road, and Golf Links Road represent the best remaining undeveloped employment lands in the city, from a locational and market perspective.

Vacant Industrial Lands

EXHIBIT 2 – VACANT INDUSTRIAL LANDS

Industrial Category	# of Sites	Land Area (gross hectares)
Business Area	49	47
Heavy Industrial	142	202
Light Industrial	264	520
TOTAL	**455**	**770**

Figure 2: Employment Land Strategy 2020

As noted in the Land Study, there is a substantial supply of undeveloped industrial lands within Thunder Bay, however sites within that are serviced and within the core employment areas are more limited.

Building Permit Activity

3.5 Non-Residential Building Permit Activity

The Consultant Team reviewed building permits provided by City staff for the period from January, 2010 – December, 2019. Over this past decade, some 2,000 non-residential permits were issued across the City of Thunder Bay. We have classified the permits into four categories: Commercial, Institutional, Industrial, and Other (the "Other" category captures properties such as utilities, performing arts centres, transportation terminals, and other mixed uses that do not fall into the prior three categories). The following are notable observations from our analysis:

- New building permits accounted for nearly one-half of the total permit value ($440 million), but represented just 12% of total permits, by count of permit.
- Permits for additions and alterations to properties – reflecting reinvestment in the stock of non-residential buildings – totaled $488 million, and an 88% share of total activity, by count of permits.
- By count of permit, the Commercial category accounted for just over one-half of total permits (52%), followed by Institutional (21%), and Industrial (13%). Buildings in the Other category represented a 14% share of the total activity.
- Commercial permits totaled $400 million in value, split evenly between new and addition/alteration work.
- Institutional permits totaled $337 million, with addition/alteration work representing a slight majority of the total permit value.
- Industrial permits totaled $57 million value, with two-thirds of the value being associated with new construction activity.

EXHIBIT 13 – VALUE AND NUMBER OF PERMITS BY BUILDING TYPE

Building Type	New		Addition/Alteration		Total	
	Value ($Millions)	#	Value ($Millions)	#	Value ($Millions)	#
Commercial	$201	89	$199	961	$400	1,050
Institutional	$149	15	$188	396	$337	411
Industrial	$38	116	$19	136	$57	252
Other	$52	14	$82	274	$134	288
TOTAL	**$440**	**234**	**$488**	**1,767**	**$928**	**2,001**

Source: City of Thunder Bay and Cushman & Wakefield

Figure 3: Employment Land Strategy 2020

5.3 Area Summary

There is a substantial supply of undeveloped industrial lands within Thunder Bay, however sites within areas that are serviced and within the core central employment areas are more limited. Absorption of Industrial land has been relatively slow with only 14 new facilities constructed between 2010 and 2019. Although absorption has been limited, it has been reported by a number of developers and real estate brokers that there appears to be some increased demand for industrial sites in the community.

5.4 Development Incentives

There are a number of incentives available in the Thunder Bay area for new investment and employment expansion in the area. We have discussed the availability of development incentives with Piero Pucci, with the Community Economic Development Commission. Most incentives, be it local, provincial or federal, are related to new community investment or new employment. There are limited incentives for the relocation of facilities that do not reflect a new employer or major expansion of an existing employer. The reported potential incentives are:

- Enbridge Gas Incentive: Contact David Sertic
Tel: 807-684-8896

The following is a program that applies to private corporations. We are uncertain if the structure of HONI would qualify for this incentive.

- Regional Opportunities Investment Tax Credit
  - The Regional Opportunities Investment Tax Credit is a 20% refundable corporate income tax credit for capital investments. The tax credit is available for expenditures in excess of $50,000 and has a cap of $500,000.
  - The Regional Opportunities Investment Tax Credit is a 20% refundable corporate income tax credit for capital investments. The tax credit is available for expenditures in excess of $50,000 and has a cap of $500,000.
  - https://budget.ontario.ca/2020/marchupdate/annex.html#section-3

Any specific incentives are discussed in the individual site write-ups if applicable.

6.0 Characteristics of the Market

6.1 National Economic Overview

The National Bank Monthly Economic Monitor (June 2021) provides the following:

- *The daily number of new cases of Covid-19 declared around the world has been declining markedly over the last month. In the developed economies, the drop can be attributed in large part to an acceleration of vaccine rollouts encouraging an outlook of fuller and more lasting reopening of economies. Elsewhere, improvement in public health is due rather to reinforcement of physical distancing rules, especially in India where in late April a flare-up of cases forced the reintroduction of strict lockdowns in some regions. Since access to vaccines is much more limited in emerging countries, herd immunity is unlikely before 2022. Developing countries will accordingly remain at greater risk of pandemic outbreaks in the coming months, a factor that could mean higher volatility of growth rates. We nevertheless continue to expect a solid rebound of the global economy in 2021 and are maintaining our forecast of 6.0% growth for the year. In fact, our confidence in a vigorous recovery has risen, since distribution of vaccines has greatly reduced economic uncertainty and downside risks for growth.*

- *The latest U.S. economic indicators confirm what has been our outlook for a few months now: a very strong revival stimulated by highly accommodative monetary and fiscal policies. Nonfarm payrolls grew 559,000 in May, less than the expected 675,000 but more than the months before, suggesting a slow but steady revival of the labour market in step with reopening of the economy. Also in May, headline 12-month CPA inflation was 5.0%, the highest in 13 years. For the CPI excluding food and energy the 12-month rise was 3.8%, the highest since June 1992. The three-month-annualized readings are still more impressive: headline inflation 8.4%, core inflation 8.3%. Up to now, the bulk of inflationary pressure has come in the goods-producing sector, but inflation could also take off in services if consumers decide, as we think they will, to spend more on activities unavailable in recent months (e.g. restaurant meals and travel). For the U.S. economy as a whole, we have left our forecast of 6.9% growth this year unchanged but have increased 2022 growth to 4.3% to reflect further government spending on infrastructure and social programs. In our projections, U.S. real GDP will be back to its potential by the third quarter of this year.*

- *Early in 2021, as the two largest provinces in Canada decreed shutdowns of non-essential businesses, public health conditions seemed to augur little good for the Canadian economy in Q1. And all the other G7 countries except the U.S. did have GDP declines during the quarter. In Canada, however, not only did the contraction that many had apprehended not materialize, but the quarter ended with very solid real growth of 5.6% annualized, a showing that put the Canadian economy in a leading position. In real terms its output came within 1.7% of its peak pre-pandemic quarter (Q4 2019) – second-best in the G7. In nominal terms the Q1 growth was even more spectacular taking nominal GDP to a best-in-G7 3.0% above its pre-recession peak. This month we are keeping our forecast of real growth in 2021 at 6.0%. after a pause in the recovery in Q2 due to public-health measures and to production backlogs in the auto industry due to microchip shortages, impressive growth can be expected to continue as vaccination picked up speed allowing the reopening of services that entail physical proximity. Our forecast for 2021 growth in nominal terms is now 12.6%, unseen in 40 years.*

Canada
Economic Forecast

(Annual % change)*	2018	2019	2020	2021	2022	Q4/Q4 2020	Q4/Q4 2021	Q4/Q4 2022
Gross domestic product (2012 $)	2.4	1.9	(5.3)	6.0	4.0	(3.1)	5.2	2.9
Consumption	2.5	1.6	(6.0)	5.0	6.2	(4.4)	5.3	5.1
Residential construction	(1.7)	(0.2)	4.1	17.9	(5.1)	14.5	2.7	(4.3)
Business investment	3.1	1.1	(13.6)	0.1	5.7	(13.9)	4.8	4.8
Government expenditures	3.2	1.7	0.4	4.8	1.7	2.4	2.9	1.5
Exports	3.7	1.3	(10.0)	5.9	5.0	(7.4)	5.2	4.7
Imports	3.4	0.4	(11.2)	7.9	5.3	(5.9)	4.8	5.1
Change in inventories (millions $)	15,486	18,766	(15,937)	4,134	13,617	(287)	16,000	13,160
Domestic demand	2.5	1.4	(4.3)	5.6	3.7	(2.0)	4.3	3.1
Real disposable income	1.5	2.2	9.5	(0.0)	(0.6)	7.4	(0.5)	1.1
Employment	1.6	2.2	(5.1)	4.4	2.8	(2.9)	3.2	2.0
Unemployment rate	5.9	5.7	9.6	7.7	6.3	8.8	6.6	6.1
Inflation	2.3	1.9	0.7	2.7	2.5	0.8	3.1	2.3
Before-tax profits	3.8	0.6	(4.0)	33.4	2.2	9.4	16.8	4.0
Current account (bil. $)	(52.2)	(47.4)	(40.1)	5.0	(38.0)	....	....	....

** or as noted*

Financial Forecast**

	Current 6/11/21	Q2 2021	Q3 2021	Q4 2021	Q1 2022	2020	2021	2022
Overnight rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.75
3 month T-Bills	0.11	0.10	0.15	0.15	0.20	0.07	0.15	0.70
Treasury yield curve								
2-Year	0.32	0.30	0.35	0.45	0.65	0.20	0.45	1.20
5-Year	0.83	0.85	1.00	1.20	1.35	0.39	1.20	1.80
10-Year	1.37	1.40	1.55	1.75	1.90	0.68	1.75	2.20
30-Year	1.93	1.95	2.05	2.15	2.25	1.21	2.15	2.45
CAD per USD	1.21	1.19	1.17	1.20	1.21	1.27	1.20	1.23
Oil price (WTI), U.S.$	71	66	72	75	70	48	75	65

*** end of period*

Quarterly pattern

	Q1 2020 actual	Q2 2020 actual	Q3 2020 actual	Q4 2020 forecast	Q1 2021 forecast	Q2 2021 forecast	Q3 2021 forecast	Q4 2021 forecast
Real GDP growth (q/q % chg. saar)	(7.9)	(38.0)	41.7	9.3	5.6	1.2	7.4	6.6
CPI (y/y % chg.)	1.8	0.0	0.3	0.8	1.4	3.2	3.2	3.1
CPI ex. food and energy (y/y % chg.)	1.8	1.0	0.6	1.1	1.0	2.0	2.3	2.2
Unemployment rate (%)	6.4	13.1	10.1	8.8	8.4	8.2	7.4	6.6

National Bank Financial

Figure 4 Source: National Bank Monthly Economic Monitor June 2021

6.2 *Real Estate Trends – MLS® Residential Average Price Trend (CREA):*

There are no reliable statistics available for employment lands in the subject market place. To provide some context of the real estate market in Thunder Bay we reference the following statistics provided by CREA.

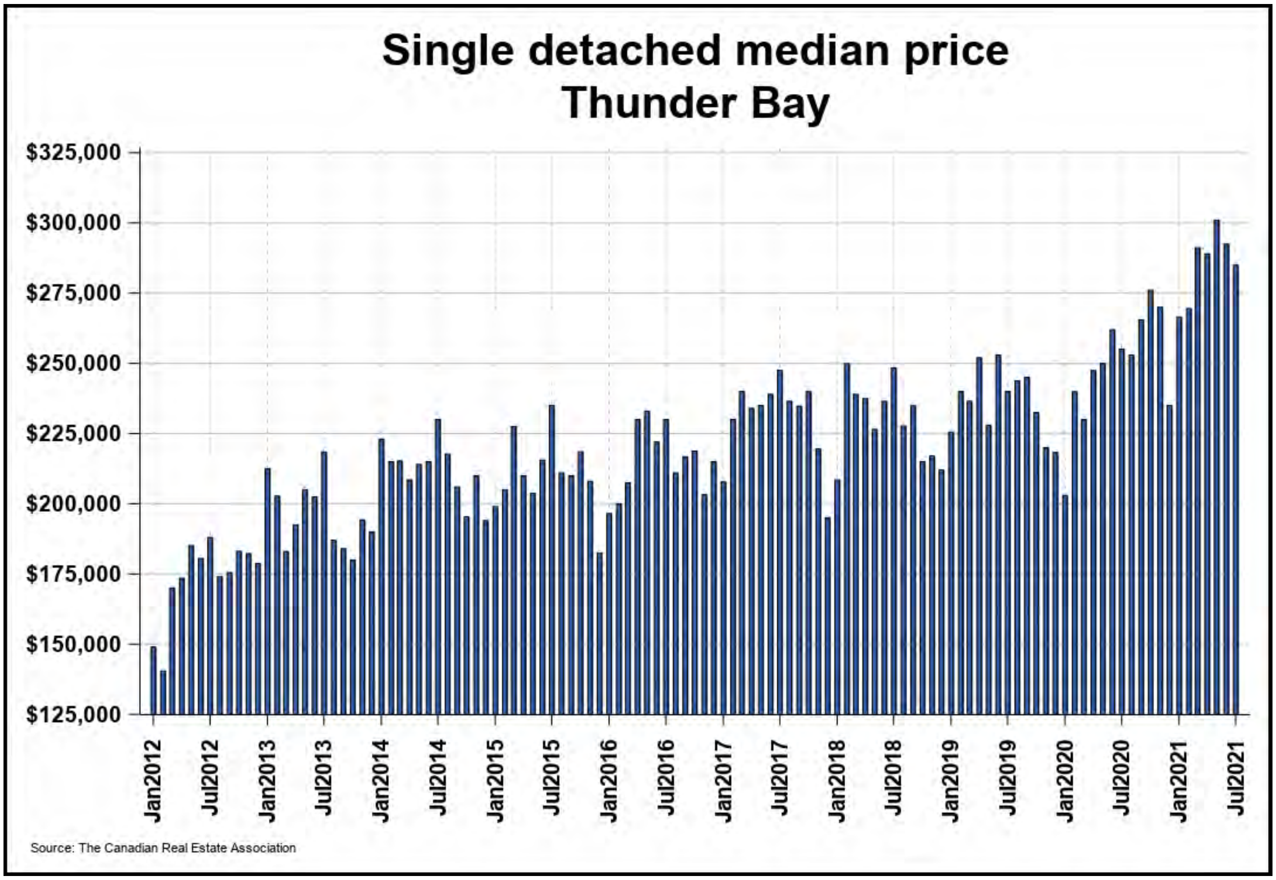


Figure 5: Source - CREA

On a year-to-date basis, single detached home sales totaled 651 units over the first seven months of the year. This was an increase of 79.8% from the same period in 2020.

The median sale price for single detached homes sold in July 2021 was $285,000, a gain of 11.7% from July 2020.

The more comprehensive year-to-date median price was $288,000, increasing by 16.9% from the first seven months of 2020.

Single detached properties spent less time on the market before selling in July 2021 than they had a year earlier. The median number of days on market for single detached home sales was 15 in July 2021, down from the 18 days recorded in July 2020.

The dollar value of all single detached home sales in July 2021 was $33.2 million, a sharp decrease of 10.5% from the same month in 2020.

7.0 Site Opportunities

Based on our extensive review there are few available development sites that meet the identified requirements. As such we have also included sites that may not meet all the requirements but are considered noteworthy.

The following Table outlines the location and site size of the potential site opportunities. Detail site writeups are provided following.

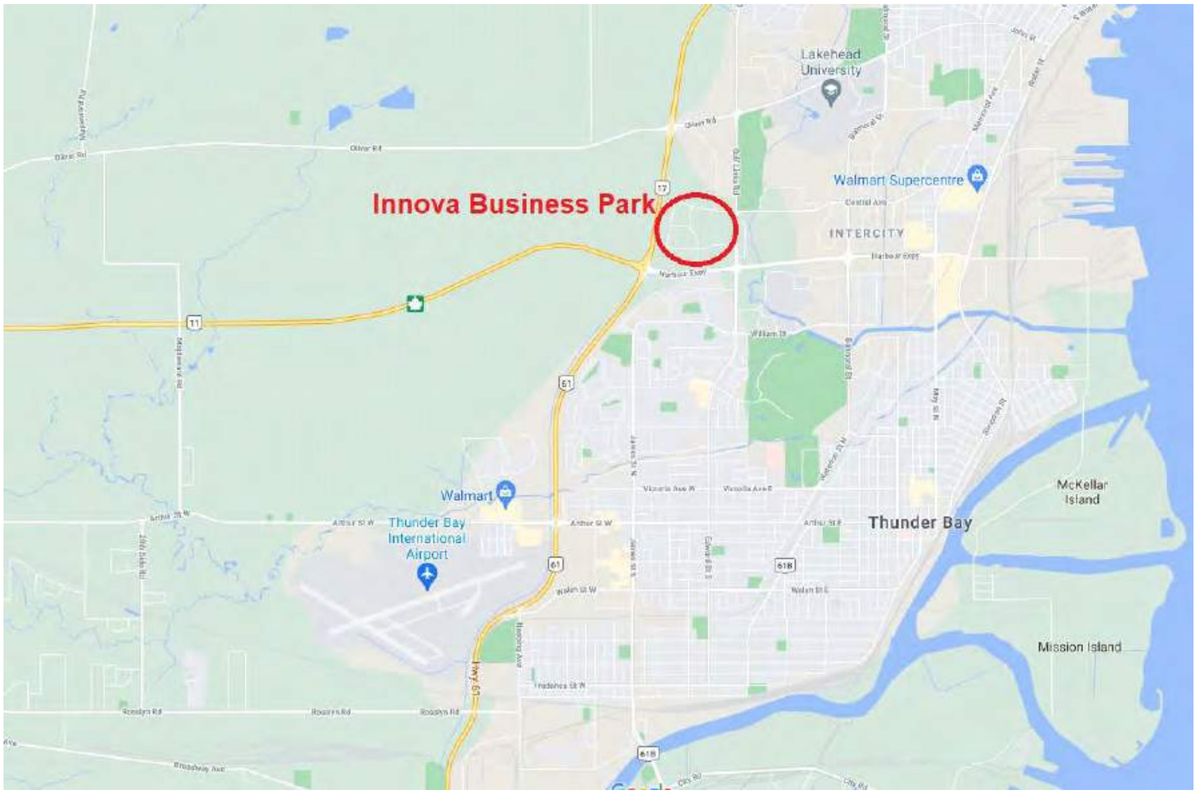
7.1 Site Opportunity Summary

Table 2

Site Summary Table			
#	**Location**	**Site Size**	**Comment**
Site Opportunities Meeting Essential Criteria			
1	Innova Industrial Park, Thunder Bay	Flexible Site Size	• Fully serviced employment land in municipal business park. • Appears to have been increased interest with a number of sites developing or with pending sales. • Only roughly 6 acres of medium industrial zoned lands (IN2) still available. Lots of Prestige Industrial available which the City has indicated would be likely suitable for the subject use although possibly requiring a zoning amendment. • May be also opportunity for a split zone site to be suitable. • Lands are generally flat but require significant muskeg removal and fill.
2	Thunder Bay Airport Industrial Park	Flexible Site Size	• Leased land only not available for purchase. • Fully serviced with no reported development constraints other than possibly height, which the client has reported is not a concern. • May be opportunity for direct airside access.
Other Site Opportunities			
3	1279 Rosslyn Road. Thunder Bay	7.5 acres Can be Severed	• Partial serviced site with no sanitary sewer. • Owner is not actively looking to sell but may consider if approached but would have to be the builder of the project. Would prefer to develop and leaseback. • Would be willing to sever into a smaller site.
4	Highway 130, Rosslyn	9.2 acres Can be Severed	• Rural services. • Would likely require a zoning amendment but the owner has reported zoning is highly flexible.
5	Cooper Road, Rosslyn	19.3 acres Can be Severed	• Rural services
6	965 Strathcona Rd	20 acres Can be Severed	• Fully serviced heavy industrial land. • Removed (18 km +/-) from airport.

7.2 *Site Opportunities – Detailed Write-Ups*

Site #1 - Innova Business Park, Thunder Bay



Nearest Intersection	Harbour Expressway & Premier Way
Municipality	City of Thunder Bay
Asking Price	$65,000 to $110,000 per acre **We note that these lands require significant excavation of muskeg and fill. We have discussed this item with a large industrial building with experience in the neighbourhood who has indicated that these costs can vary widely. Approximate costs were suggested to be in the range of $100K to $125K per acre.**
Listing Status	Actively listed directly from City of Thunder Bay. The following lotting map identifies the sites that remain available within the development.
Listing Contact	Joel DePeuter 1-807-625-2991 Joel.DePeuter@thunderbay.ca
Owner	City of Thunder Bay
PIN #	Multiple PIN's: Sites severed once sold.
Lot Area (acres)	Lots ranging in size from 0.79 acres to 5.79 acres with assembly potential
Services Available	Full Services including Municipal water, sanitary, hydro & gas.

COMMENTS	
Location	These lots are located within a more recently developed Innova Business Park located west of the Thunder Bay Expressway (Highway 11-17) between Harbour Expressway and Central Avenue. This area is approximately 4 kms from the Thunder Bay International Airport Overall, the area has developed gradually but has seen some increased uptake more recently.
Land Use	Official Plan: Light Industrial Zoning: Lots 6-20 - IN2 (Medium Industrial Zone) Lots 1-47 - IN6 (Prestige Industrial Zone) The Innova Business Park is zoned into two categories being medium and prestige industrial. Medium Industrial Zone (IN2): Allows for light and medium industrial uses including service, transport, outdoor storage and utility uses. Prestige Industrial Zone (IN6): Allows for a narrower range of uses limited to industrial centre, light industrial use, technical office, and research and development. The zone also allows for financial, drive service units, recreational, restaurant when used together with a permitted use. In addition to the two zoning designations, the lots facing westerly toward the Thunder Bay Expressway and the lots facing southerly toward the Harbour Expressway may be subject to MTO and LRCA approvals and permits. We have discussed the potential for the proposed subject use on the lands zoned Prestige Industrial with Joel DePeuter. Although not explicitly permitted, Mr. DePeuter has indicated that given the large portion of subject office, such a use may be supported on the IN6-Prestige Industrial lands. Ultimately this would require negotiations with the City and is not a certainty. The IN2-Medium Industrial zoning would support the subject use.
Site Description	The Business Park has not yet been severed into individual parcels creating flexibility with regard to site size and configuration. The city has provided a conceptual lotting map which can be found. The lands are generally level and mostly cleared or with scrub brush. These lands have substantial excavation and fill requirements due to muskeg. The extent of the required removal and fill is dependent on the specific location with some locations requiring more fill. The City of Thunder Bay has the depths of Muskeg however this is not publicly available and is only provided once approached by a potential applicant.

Other Criteria	Development Charges	None
	Development Incentives	None
	Distance to Airport	4 kms +/-
	Distance to Hotel / Food Services	1.5 kms +/-
	Development Constraints and Risks	Site works related to Muskeg removal. City has reported that they have testing data that can be shared at negotiation.
	Distance to Major Highway	Immediate proximity to Trans-Canada Highway and Thunder Bay Expressway.
	Tax Rates (2021)	Industrial Occupied - 4.289451% Industrial Excess Land - 4.289451% Vacant Land - 4.289451%

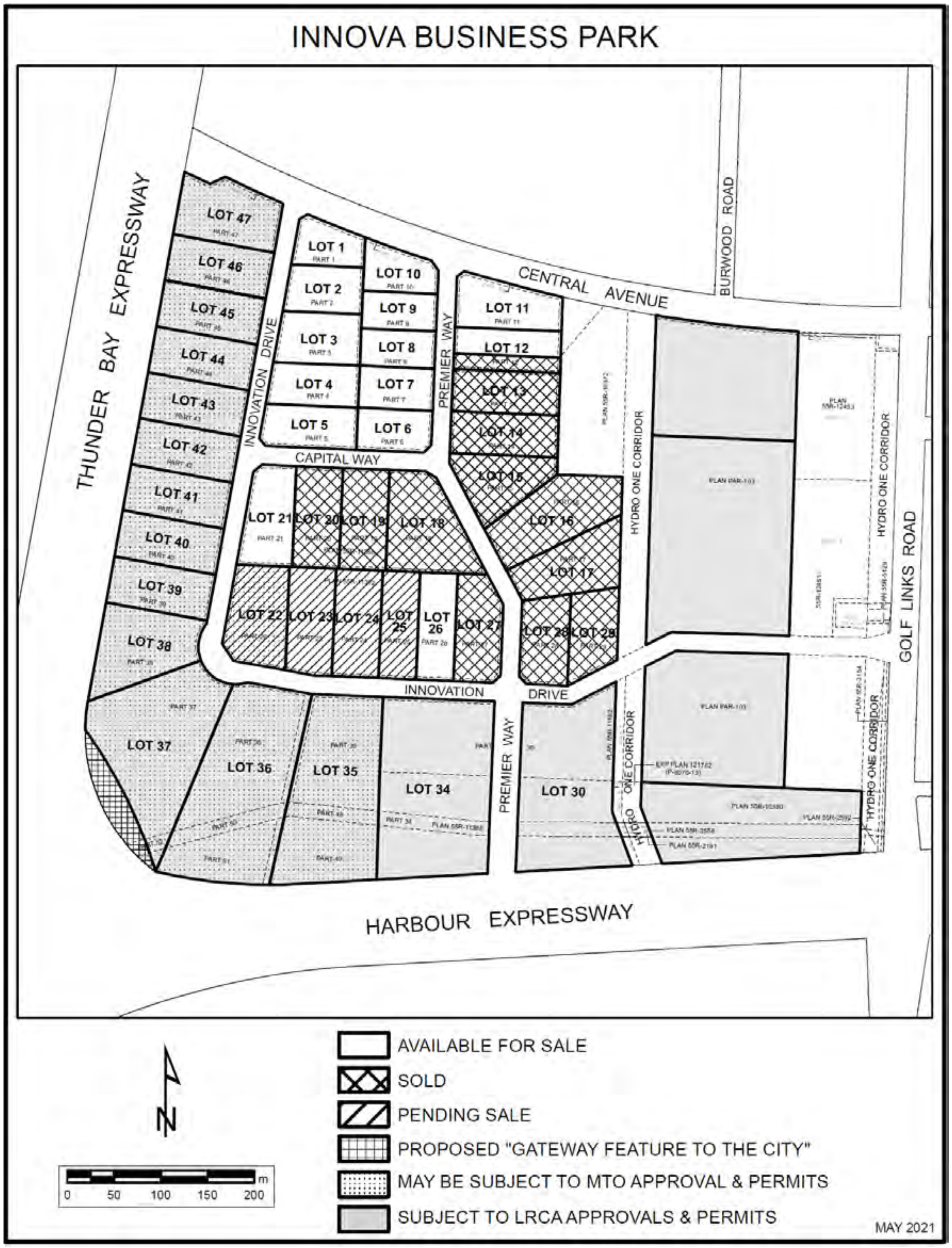
ADDITIONAL MAPS AND PHOTOS

Photos

ADDITIONAL MAPS AND PHOTOS

Conceptual Lotting Map

The following diagram outlines the available lots within the Innova Park. We note the large parcels to the east of the Hydro Corridor are also no longer available.



Site #2 - Derek Burney Drive, Thunder Bay
Thunder Bay International Airport Lands

Nearest Intersection	Thunder Bay Expressway (Hwy 61) & Arthur Street West
Municipality	City of Thunder Bay
Listing Status	These lands are within the Thunder Bay International Airport. As such these lands are not available for purchase but rather for lease.
Asking Price	Lease Rates: In the Range of $0.40 to $0.45 per sq.ft.
Listing Contact	Ed Schmidtke 1-807-473-2602 schmide@tbairport.on.ca
Owner	Her Majesty The Queen In The Right Of Canada
PIN #	Part of: 620190087
Lot Area (acres)	The light industrial lands are a roughly 70 acre pocket with flexibility on site size and layout. The preferred location would be the easterly limit of the Light Industrial Lands as identified on the above diagram as to not leapfrog vacant land.
Services Available	Full Municipal Services: Sanitary, Water, Hydro & Gas.

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">The property is located in the northern portion of the Thunder Bay International Airport site, at the southwest corner of the Thunder Bay Expressway (Hwy 61) & Arthur Street West. The light industrial lands more specifically front Derek Burney Drive which is accessed from Hawker Rd via Arthur Street West.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Airport

Zoning: Airport (AP)

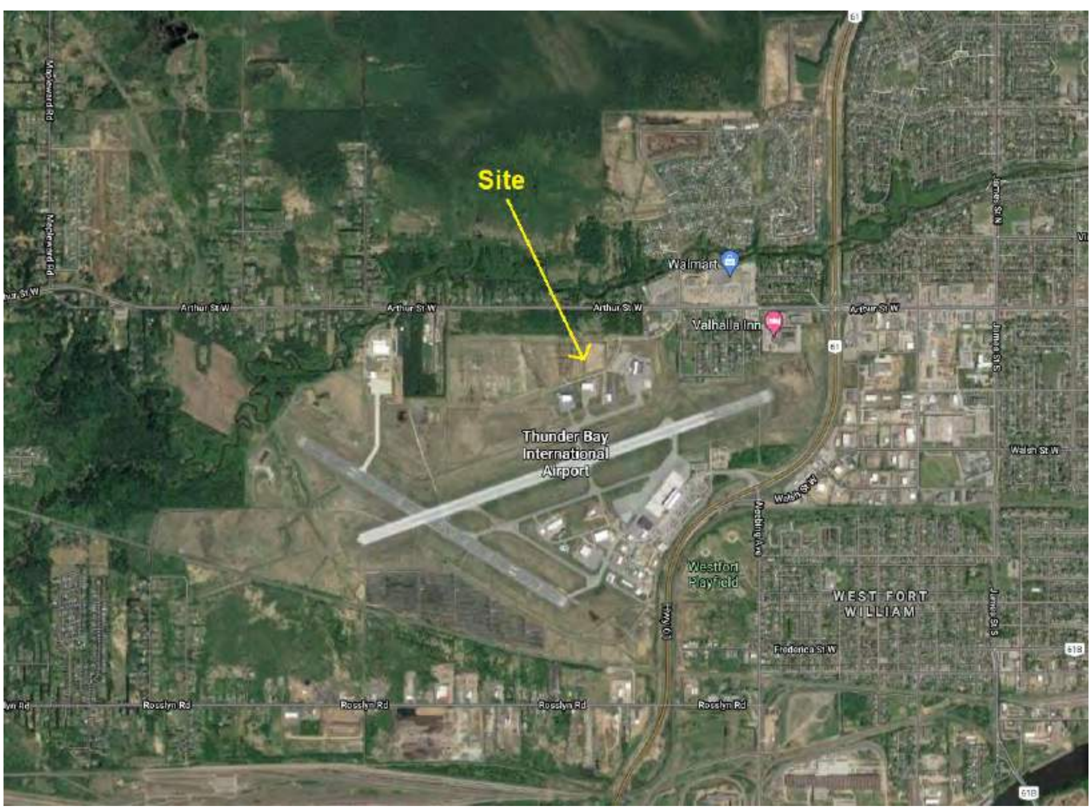
Airport (AP): This zoning allows for a range of uses including “Aerospace Related Light Industrial Use” and “Aerospace Related Medium Industrial Use”. Aerospace related uses describes a “use associated with or serving an airport, or directly related to the operation of aircraft”. The subject use may not meet this criteria however we have discussed the zoning restrictions with the airport CEO Ed Schmidtke.

Correspondence with Ed Schmidtke has indicated that Zoning is very flexible and fits with the described subject use. As such it appears that the subject use would be permitted on the Light Industrial Lands.</td></tr>
<tr><td>Site Description</td><td colspan="2">The property represents a large parcel of land that includes the airport. The light industrial lands are roughly 70 acres and can be readily divided into smaller leased parcels. The site is cleared and roughly flat.</td></tr>
<tr><td rowspan="7">Other Criteria</td><td>Development Charges</td><td>None</td></tr>
<tr><td>Development Incentives</td><td>None</td></tr>
<tr><td>Distance to Airport</td><td>At Airport</td></tr>
<tr><td>Distance to Hotel / Food Services</td><td>Immediate Neighbourhood</td></tr>
<tr><td>Development Constraints and Risks</td><td>No noted development constraints other than likely height requirements for being in proximity to an airport.</td></tr>
<tr><td>Distance to Major Highway</td><td>Access to Hwy 61 (Thunder Bay Expressway) is approximately 1 km to the east of the site.</td></tr>
<tr><td>Tax Rates (2021)</td><td>Industrial Occupied - 4.289451%
Industrial Excess Land - 4.289451%
Vacant Land - 4.289451%</td></tr>
</table>

ADDITIONAL MAPS AND PHOTOS

Photos of Site (Google Street View)

Location Map



Site #3 - 1279 Rosslyn Road, Thunder Bay

Nearest Intersection	Thunder Bay Expressway (Hwy 61) & Neebing Ave
Municipality	City of Thunder Bay
Listing Status	The property is not actively listed for the sale. The owner is a large commercial construction company who has indicated that they would prefer to develop and leaseback to the tenant but may consider a sale.
Asking Price	The owner has provided the following: *Without Prejudice: If I was interested in selling I would think for 5 acres I would be looking for $700,000 and a guarantee to build for the owner.*
Listing Contact	Ken Perrier 1-807-474-0930 perhol@perhol.com
Owner	1648841 Ontario Ltd. (Perhol Construction)
PIN #	Part of: 620180032; 620180031; 620180030; 620180024
Lot Area (acres)	The owner has indicated that they have a total of 7.5 acres +/- available that could be assembled / divided.
Services Available	Partial Services: Municipal water, hydro & gas. Requires private septic.

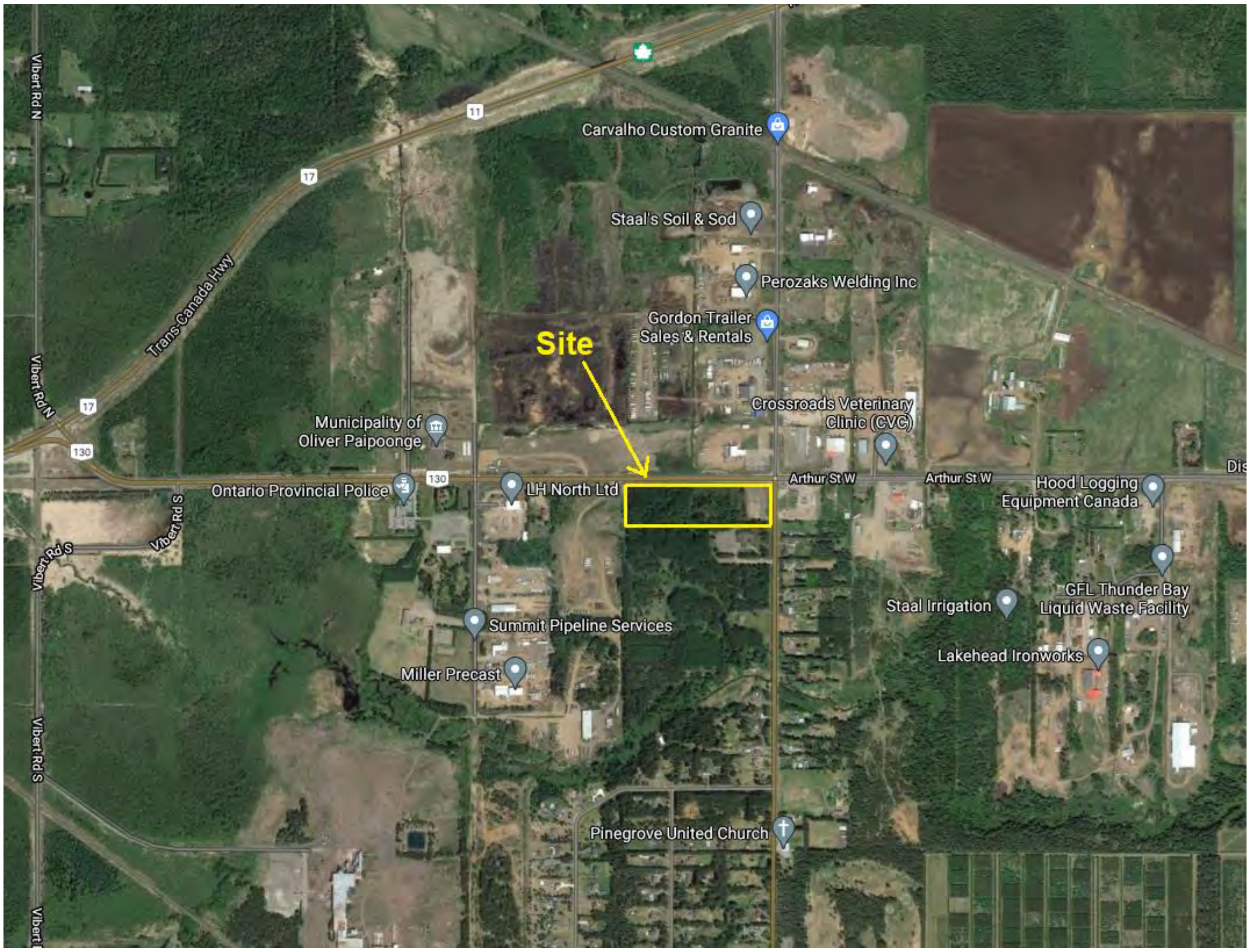
COMMENTS		
Location	This site is located on the north side of Roslyn Road, approximately 300 metres west of Hwy 61. The site is immediately south of the Thunder Bay International Airport. Access to Rosslyn Road is not directly available from Highway 61 but rather is accessed to the north via Neebing Road. Access to Highway 61 and the entrance to the airport is roughly 2 km.	
Land Use	Official Plan: Light Industrial Zoning: IN2-N (Medium Industrial Zone) Medium Industrial Zone (IN2): Allows for light and medium industrial uses including service, transport, outdoor storage and utility uses. The IN2-Medium Industrial zoning would support the subject use. “N” Suffix - Development on lands that have the suffix "N" may require noise studies and/or the implementation of noise mitigation measures prior to the issuance of any permit.	
Site Description	The property represents an approximately 7.5 acre assembled parcel of land that has an “L” shape. The site is cleared and generally level.	
Other Criteria	Development Charges	None
	Development Incentives	None
	Distance to Airport	2 kms +/-
	Distance to Hotel / Food Services	2 kms +/-
	Development Constraints and Risks	None Reported; Proximity to airport may have height requirements. May require sound study.
	Distance to Major Highway	Access to Hwy 61 (Thunder Bay Expressway) is approximately 2 km from the subject.
	Tax Rates (2021)	Industrial Occupied - 4.289451% Industrial Excess Land - 4.289451% Vacant Land - 4.289451%

ADDITIONAL MAPS AND PHOTOS

Photos of Site (Google Street View)

Location Map

Site #4 - Highway 130 , Rosslyn



Nearest Intersection	Arthur Street / Highway 130 & Twin City Crossroad
Municipality	Municipality of Oliver Paipoonge
Listing Status	The property is not actively listed for the sale. The owner is a large commercial construction company who has indicated that they would be willing to sell a portion of the site.
Asking Price	$550,000 for 6 acres ($91,670 per acre +/-) – Note the outlined site is the entire 9.2 acre larger site.
Listing Contact	John Simperl 1-807-623-1855 john.simperl@brunocontracting.com
Owner	Bruno's Contracting (Thunder Bay) Limited
PIN #	622950301
Lot Area (acres)	The site has a total area of 9.2 acres +/-. The owner has reported that the site could be divided.
Services Available	Rural Services: Hydro & Gas; Would require private well & septic

COMMENTS		
Location	This site is located in the rural community of Rosslyn, approximately 9 km west of the Thunder Bay Airport. The site is situated at the southwest corner of Arthur Street W and Twin City Crossroad. The immediate neighbourhood is a small concentration of rural service commercial / industrial type uses. Many of the nearby uses are transportation and equipment related. Residential development is found farther to the south.	
Land Use	Official Plan: Commercial Zoning: GC- General Commercial Zone General Commercial Zone (GC): This zone allows for commercial and service commercial type uses. The zoning allows for office uses but does not provide for light or medium industrial uses. Yard storage appears to be only permitted in conjunction with permitted use such as equipment sales. It is unlikely that the proposed use would be permitted in this designation. The use would be likely defined as a Light Industrial use in the Zoning By-Law. A rezoning and OPA may be required to allow for the subject use. The property owner has indicated that the Township is very receptive and supportive of zoning and official plan amendments. The application fees for an OPA is $1,500 while a rezoning is $1,545 in addition to any planning and study costs.	
Site Description	The property represents a 9.2 acre rectangular shaped parcel that is reported to have severance potential. The site has roughly 1 acre of cleared area at the east limit that is improved with a gravel yard. The remainder of the site is forested. Overall, the site appears to be generally flat.	
Other Criteria	Development Charges	None
	Development Incentives	No development changes and relatively low tax rates.
	Distance to Airport	9 kms +/-
	Distance to Hotel / Food Services	9 kms +/-
	Development Constraints and Risks	None Reported
	Distance to Major Highway	Access to Hwy 17 (Trans Canada Hwy) is approximately 2 km west of the site.
	Tax Rates (2021)	Industrial – 2.972052% Industrial Vacant Land – 1.931834%

ADDITIONAL MAPS AND PHOTOS

Photos of Site (Google Street View)

Location Map

Site #5 - Cooper Road, Rosslyn

Nearest Intersection	Cooper Road & Highway 130
Municipality	Municipality of Oliver Paipoonge
Listing Status	The property is not actively listed for the sale. The owner is a large commercial construction company who has indicated that they would be willing to sell a portion of the site.
Asking Price	$550,000 for 6 acres ($91,670 per acre +/-) – Note the outlined site is the entire 19.3 acre larger site.
Listing Contact	John Simperl 1-807-623-1855 john.simperl@brunocontracting.com
Owner	North Star Holdings Incorporated
PIN #	622950686 & 622950591
Lot Area (acres)	The site has a total area of 19.3 acres +/-. The owner has reported that the site could be divided.
Services Available	Rural Services: Hydro & Gas; Would require private well & septic

COMMENTS

Location	This site is located in the rural community of Rosslyn, approximately 9 km west of the Thunder Bay Airport. The site is situated at the end of the developed portion of Cooper Road. The immediate neighbourhood is a small concentration of rural service commercial / industrial type uses. Many of the nearby uses are transportation and equipment related. Residential development is found farther to the south.	
Land Use	Official Plan: Industrial Zoning: Light Industrial (LI) Light Industrial (LI): This zone allows for a range of industrial uses including commercial garage, contractors yard, light industry and warehouse. Based on the permitted uses the subject use appears to be supported.	
Site Description	The property represents a 19.3 acre +/- rectangular shaped parcel that is reported to have severance potential. The site is mostly forested.	
Other Criteria	Development Charges	None
	Development Incentives	No development changes and relatively low tax rates.
	Distance to Airport	9 kms +/-
	Distance to Hotel / Food Services	9 kms +/-
	Development Constraints and Risks	None Reported
	Distance to Major Highway	Access to Hwy 17 (Trans Canada Hwy) is approximately 2 km west of the subject.
	Tax Rates (2021)	Industrial – 2.972052% Industrial Vacant Land – 1.931834%

ADDITIONAL MAPS AND PHOTOS

Photos of Site (Google Street View)

Location Map

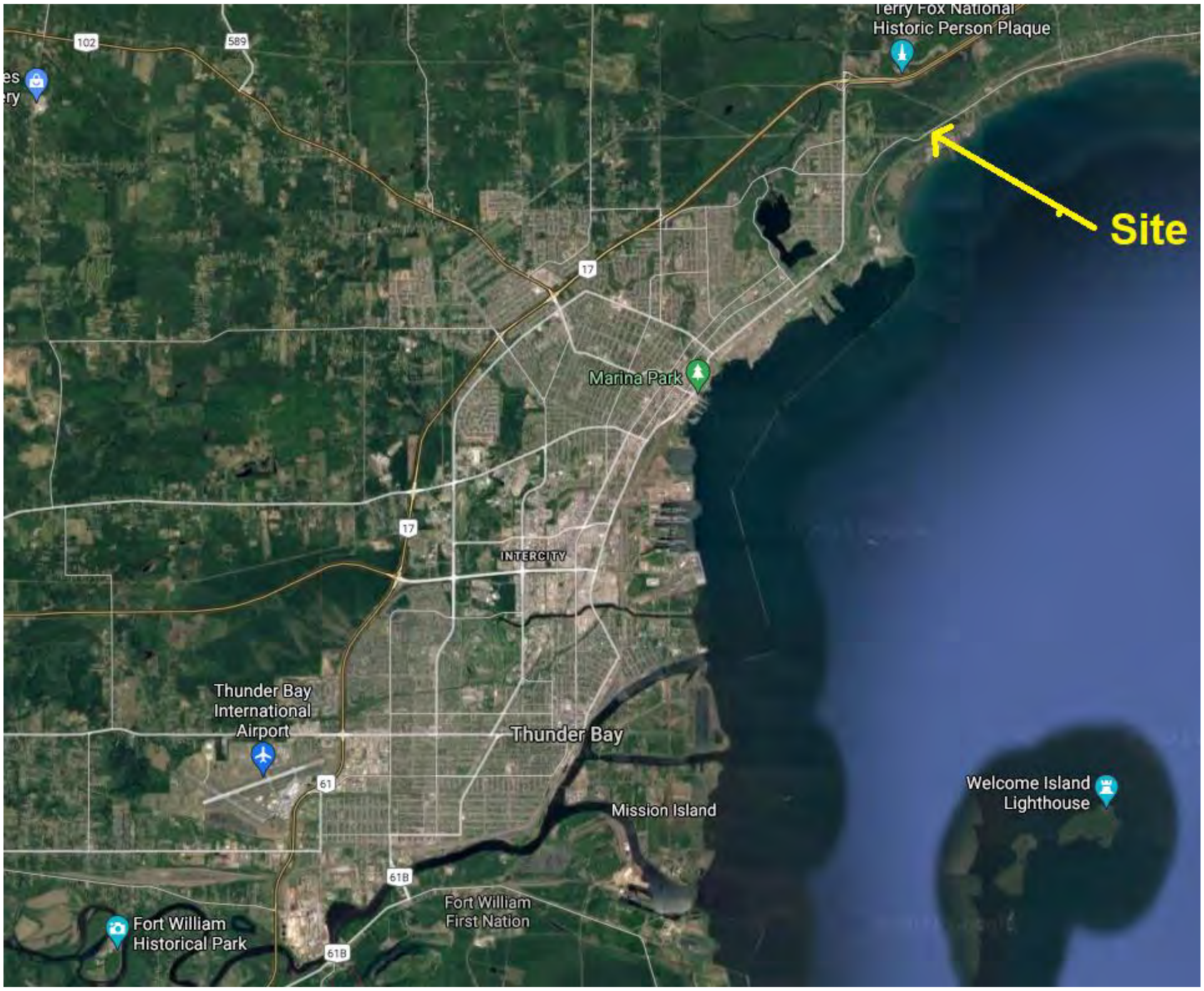
Site #6 - 965 Strathcona Avenue, Thunder Bay

Nearest Intersection	Hodder Ave & Arundel Street
Municipality	City of Thunder Bay
Listing Status	Private Listing
Asking Price	$1,500,000 for 20 acres ($75,000 per acre) Would sever and sell smaller parcel
Listing Contact	Ian Bodnar 1-807-621-6358
Owner	ARA Holdings Inc.
PIN #	622620006
Lot Area (acres)	Larger Parcel – 20 acres; Roughly 14 acres to the west of Shipyard Rd. *Owner willing to divide into smaller parcels.
Services Available	Full Municipal Services: Sanitary, Water, Hydro & Gas.

COMMENTS		
Location	The property is located near the northern limit of Thunder Bay, on the south side of Strathcona Avenue. This site is part of the former Abitibi Paper Mill property that encompassed a large waterfront industrial parcel including a mill, warehouse and office. The property is roughly 4 km from the Hodder Avenue intersection with Highway 17.	
Land Use	Official Plan: Heavy Industrial Zoning: Heavy Industrial Zone (IN3) Heavy Industrial Zone (IN3) provides for a wide range of industrial uses including outdoor storage. It appears this zoning designation would support the subject use.	
Site Description	The property represents a 25-acre parcel of land that is somewhat narrow in shape (relative to the size), lying between Strathcona Ave on the north side and a railway on the south side. The site is bisected by Shipyard Rd, which appears to be a private road accessing the larger Abitibi Mill property. Roughly 14 acres are situated to the west of Shipyard Rd. These lands are reported to be cleared sloping gradually from north to south.	
Other Criteria	Development Charges	None
	Development Incentives	None
	Distance to Airport	18 kms +/-
	Distance to Hotel / Food Services	7 to 18 kms +/-
	Development Constraints and Risks	No noted development constraints.
	Distance to Major Highway	Access to Hwy 17 is approximately 4 kms northwest of the site.
	Tax Rates (2021)	Industrial Occupied - 4.289451% Industrial Excess Land - 4.289451% Vacant Land - 4.289451%

ADDITIONAL MAPS AND PHOTOS

Location Map



8.0 Building Opportunities

Based on our extensive review there are very few existing facilities that that meet the identified site requirements with a building that may be suitable with or without renovations. We have found two existing facilities that are being marketed that are considered to be a possible option.

Existing Facility #1 - 1820 Bailey Rd, Thunder Bay

Nearest Intersection	Arthur Street / Highway 130 & Twin City Crossroad
Municipality	City of Thunder Bay
Listing Status	Currently listed for lease at an asking rate of $6 per sq.ft.. Listing agent has noted that the owner would also be willing to sell. A portion of the building is currently leased.
Asking Price	$1,500,000 +/-
Listing Contact	Bob Phaff 1-807-473-7644 bob@bobpfaff.com
Owner	ARA Holdings Inc.
PIN #	620060068
Lot Area (acres)	6.75 acres
Building Size	25,000 sq.ft. – Mostly Warehouse Space
Services Available	Full Services: Municipal Water & Sanitary, Hydro & Gas

COMMENTS		
Location	The property is located in the southern portion of Thunder Bay, within an older concentration of industrial development. Much of the industrial development is heavy uses. Some residential is present along Bailey Road which is a dead-end road.	
Land Use	Official Plan: Light Industrial Zoning: Medium Industrial Zone (IN2) Medium Industrial Zone (IN2): Allows for light and medium industrial uses including service, transport, outdoor storage and utility uses. The IN2 - Medium Industrial zoning would support the subject use.	
Site Description	The site represents 6.75 acre irregular shaped parcel. The site shape curves along a rail corridor on the north limit and wraps around the rear of residences on Baily Road. The site is cleared and appears to be generally level although we note we were unable to see the rear portion of the site.	
Building Description	The property is improved as a warehouse / service shop facility that was constructed in stages. Most of the building was constructed between 1964 to 1973 with an addition in 1991. The building has a reported total size of 25,000 sq.ft. with minimal office space. The building is a mix of concrete block and steel construction. The main building is reported to have 16' doors at each end, 20' ceiling clearance, and an overhead crane. Overall the building appears to be dated and in average condition at best.	
Other Criteria	Development Charges	None
	Development Incentives	None
	Distance to Airport	3.5 kms +/-
	Distance to Hotel / Food Services	4 kms +/-
	Development Constraints and Risks	None Reported – We note this an old site and we are not aware of the past uses.
	Distance to Major Highway	Access to Hwy 61 is approximately 3.5 kms west of the site.
	Tax Rates (2021)	Industrial Occupied - 4.289451% Industrial Excess Land - 4.289451% Vacant Land - 4.289451%

ADDITIONAL MAPS AND PHOTOS

Photos of Building

Location Map

Existing Facility #2 - 965 Strathcona Road, Thunder Bay

Nearest Intersection	Hodder Ave & Arundel Street
Municipality	City of Thunder Bay
Listing Status	Private Listing
Asking Price	$2,000,000 – Office Building + 6 acres +/-
Listing Contact	Ian Bodnar 1-807-621-6358
Owner	ARA Holdings Inc.
PIN #	Part of Larger Parcel with Multiple Pin #'s
Lot Area (acres)	6 acres +/-
Building Size	38,000 sq.ft. Including Basement – Two Storey Office Building
Services Available	Full Services: Municipal Water & Sanitary, Hydro & Gas

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">The property is located near the northern limit of Thunder Bay, on the south side of Strathcona Avenue. This site is part of the former Abitibi Paper Mill property that encompassed a large waterfront industrial parcel including a mill, warehouse and office. The property is roughly 4 km from the Hodder Avenue intersection with Highway 17.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Heavy Industrial

Zoning: Heavy Industrial Zone (IN3)

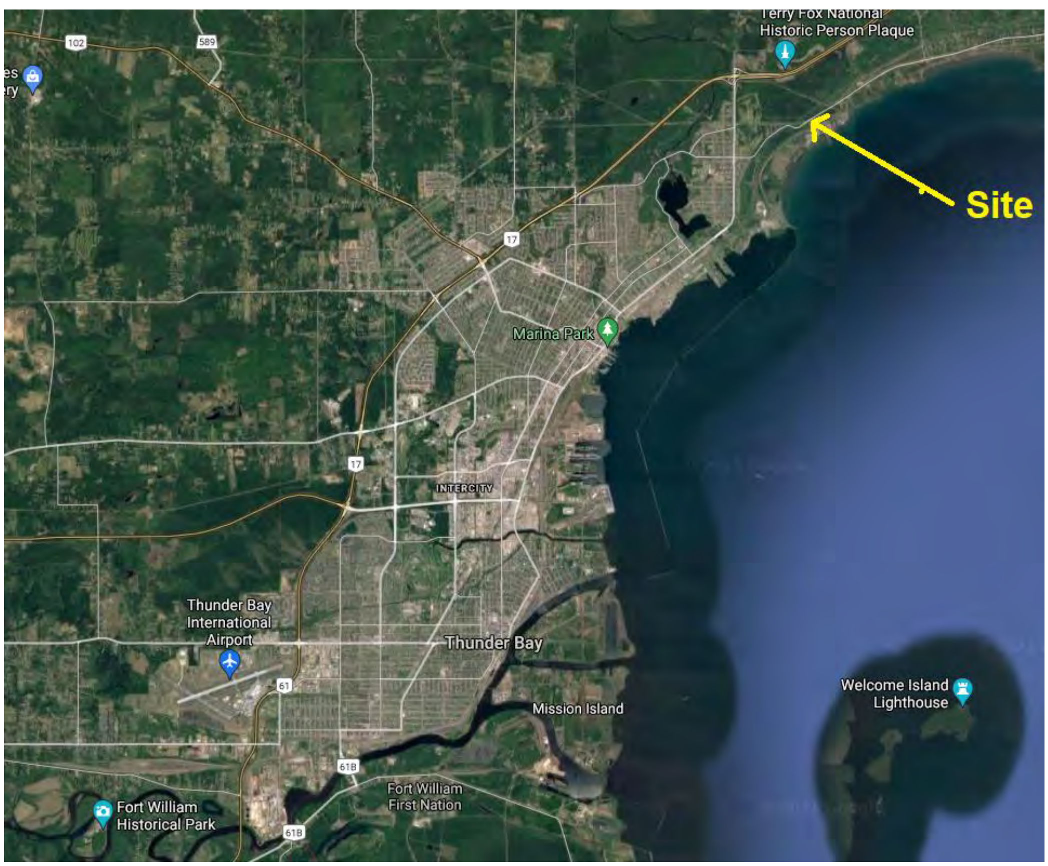
Heavy Industrial Zone (IN3) provides for a wide range of industrial uses including outdoor storage. It appears this zoning designation would support the subject use.</td></tr>
<tr><td>Site Description</td><td colspan="2">The property represents a proposed roughly 6-acre parcel of land that is currently part of a larger site. The parcel is comprised of two parts lying on either side of a railway. The lands to the south of the railway are improved with an office building and a large paved parking lot reportedly suitable for roughly 200 vehicles and improved with electrical outlets. The lands to the north are vacant and appear to be partially forested.</td></tr>
<tr><td>Building Description</td><td colspan="2">The building is a two storey brick clad office building with a full basement. The building is marketed as being 38,000 sq.ft. which appears to include the basement space. The building is reported to be in good condition with some updates completed in recent history. A portion of the building is currently leased but can be provided vacant in the 45 days if needed.

We note the larger property is also improved with a 50,000 sq.ft. warehouse developed along a container boat slip and with rail access. This building would require a larger site if included with the office portion.</td></tr>
<tr><td rowspan="7">Other Criteria</td><td>Development Charges</td><td>None</td></tr>
<tr><td>Development Incentives</td><td>None</td></tr>
<tr><td>Distance to Airport</td><td>18 kms +/-</td></tr>
<tr><td>Distance to Hotel / Food Services</td><td>7 to 18 kms +/-</td></tr>
<tr><td>Development Constraints and Risks</td><td>No noted development constraints.</td></tr>
<tr><td>Distance to Major Highway</td><td>Access to Hwy 17 is approximately 4 kms northwest of the site.</td></tr>
<tr><td>Tax Rates (2021)</td><td>Industrial Occupied - 4.289451%
Industrial Excess Land - 4.289451%
Vacant Land - 4.289451%</td></tr>
</table>

ADDITIONAL MAPS AND PHOTOS

Photos of Building

Location Map



9.0 Beaverhall Industrial Area - Benchmark Land Value

As per the Terms of Reference we have been requested to provide a benchmark value range for industrial lands within the neighbourhood of the current "Remotes" facility at 680 Beaverhall Place. There are a number of vacant parcels within this neighbourhood within relatively close proximity to the existing facility.

The following table and diagram identify the primary parcels of vacant land within the subject neighbourhood.

Table 3

Vacant Neighbourhood Sites				
#	**Location**	**Site Size**	**PIN # / Owner**	**Last Sale Price / Date**
1	625 Beaverhall Place	1.69	620430049 / 1383793 Ontario Inc.	\$300,000 / Sept 2014
2	645 Beaverhall Place	1.81	620430091 / Sparcon Construction Inc	\$325,000 / Nov 2020
3	600 Beaverhall Place	1.56	620430043 / 2786341 Ontario Ltd.	\$250,000 / Dec 2020
4	625 Mountdale Ave	1.45	620430089 / Mahon Electric Company Ltd	\$167,000 / May 2016

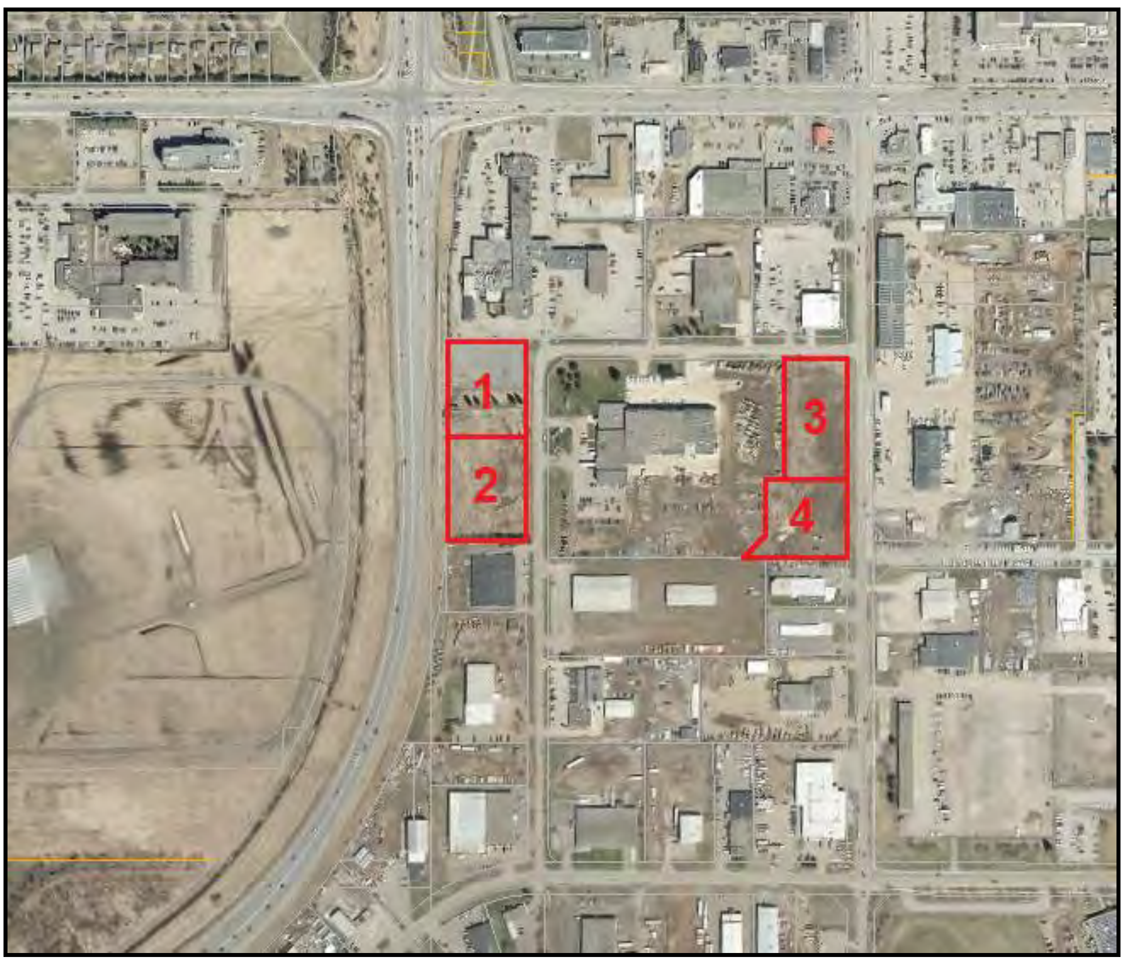


Figure 6

9.1 Direct Comparison Approach

The Direct Comparison Approach provides a basis for value through a process of adjustments for differences between comparable sales and the subject property. In this method, similar properties recently sold or offered for sale are analysed and comparisons are made based on a number of elements of comparison. These elements include real property rights conveyed, financial terms, condition of sale, expenditures made immediately after purchase, market conditions, location, physical characteristics, economic characteristics, use and zoning, and non-realty components of value. Elements that apply can be addressed quantitatively or qualitatively.

A unit of measurement is defined as a feature of a property that can be measured, for purposes of comparison, with the same common element or component of another property. For example, a selling price per “unit” could express a figure on a per square foot basis, per acre basis, per suite basis, or per room basis.

In this approach, similar properties recently sold or offered for sale are analysed and comparisons are made based on a number of elements of comparison. Elements of Comparison include:

- ***Real Property Rights Conveyed***
  Adjustments are made under this category for items such as existence of right of ways, easements, restrictive covenants which may impact the property.

- ***Financial Terms (financing)***
  Differences in financing arrangements that result in a higher or lower transaction price.

- ***Condition of Sale***
  Motivation of the buyer or seller that differs from the usual market conditions resulting in a sale that would not represent the market value of a property. This adjustment could be in the form of the vendor needing to make a quick sale due to a cash flow problem, a neighbouring property owner motivated to expand, or might emerge for a key property in an assembly.

- ***Expenditures Made Immediately After Purchase***
  Any expenses which a knowledgeable buyer would have considered and affected the price paid.

- ***Non-Realty Components***
  Any non-realty items such as personal property and business operations included in the sale price of the comparable.

These preceding adjustments are made before adjustment for market conditions (time).

- ***Market Conditions***
  Adjustments made for changes over time due to inflation, deflation or changes in investors' perceptions of the market. In the cases where a listing is considered it may be that a downward adjustment should be applied as typically properties sell for less than the asking price.

Following market adjustments, adjustments are made under the following main headings on a percentage or dollar basis as deemed appropriate.

- ***Location***

- ***Physical Characteristics***
  Physical differences such as site and building size, condition, accessory buildings etc.

- ***Economic Characteristics***
  Adjustments for attributes that directly affect its income. This element is usually applied to income-producing properties.

- ***Use and Zoning***
  Difference in current use potential of a comparable and the subject property.

Qualitative vs. Quantitative

Adjustments can be in the form of quantitative and/or qualitative adjustments. Quantitative adjustments may be applied as a percentage or dollar amount. Qualitative adjustments do not apply specific adjustments to sales but rather relies on comparisons. Qualitative techniques include trend analysis, relative comparison analysis and ranking analysis. In this instance we have completed a Quantitative analysis.

A survey of the local market area has been conducted and the following sales are concluded to best support value for the subject property. Detailed sales descriptions and sales location maps can be found in the Addenda of this report.

9.2 Direct Comparison Approach Table

Table 4

#	Location – Thunder Bay	Lot Size (acres)	Zoning	Sale Price	Sale Date / Registration Date	Time Adjusted Rate per Acre (rounded)	Adjustments Applied			Adjusted Value Per acre
	Neighbourhood Sales						**Location**	**Site Size / Scale**	**Topography**	
1	645 Beaverhall Place	1.81	Light Industrial	$325,000	11/26/20	$187,000				**$187,000**
2	600 Beaverhall Place	1.56	Medium Industrial	$250,000	12/04/20	$166,000				**$166,000**
3	685 Beaverhall Place	0.86	Light Industrial	$300,000	06/25/21	$350,000		↓		**$262,500**
4	625 Mountdale Ave	1.45	Medium Industrial	$167,000	5/04/16	$133,000				**$133,000**
5	625 Beaverhall Place	1.69	Highway Commercial	$300,000	9/09/14	$210,000				**$210,000**
	Other Sales									
6	295 Court St S	3.48	Medium Industrial	$1,150,000	7/30/21	$330,000	↓			**$231,000**
7	Dunlop St	1.09	Medium Industrial	$151,000	3/18/21	$141,000			↑	**$183,300**
8	224 Burwood Road	2.83	Prestige Industrial Hold	$399,900	1/15/20	$154,000	↑		↑	**$215,600**

↑ - Inferior to the Subject; ↓ - Superior to the Subject

9.3 Benchmark Land Value Analysis

The preceding Table outlines 8 sales of employment lands located in the City of Thunder Bay. The sales include 7 sites zoned for light or medium industrial uses and one neighbourhood sale zoned highway commercial. Five of the sales are from within the study area while 3 are within other industrial locations throughout Thunder Bay.

Majority of the sales are relatively recent being from 2020 or 2021. Two of the sales are dated but have been included due to the location within the immediate study area. Industrial /employment land values appear to have experienced some upward pressure over the past year or so while values had been more stagnant prior to this. We have applied a time adjustment of 1.5% per annum to the end of 2019 and a 6% per annum adjustment for 2020 and 2021. Once adjusted the sale provides a time adjusted sale price range of $133,000 to $350,000 per acre.

The wide time adjusted price range is primarily a result of differences in location, topography and site size / scale. Adjustments have been applied to account for these items.

Index 1 to Index 5 are all located in the immediate study area. All the sites are cleared and generally flat. Some zoning differences are present but all sites appear to provide for a range of employment uses. Index 5 is zoned for commercial, however, this is related to the former hotel use and it is likely that an alternate light industrial use would be suitable. One sale is much smaller at 0.86 acres and required and adjustment for scale. Once adjusted these sales indicate a range of $133,000 to $262,500 per acre. The lower end of the range represents a dated sale of a nearby site. Although adjusted for time the adjustment may not adequately account for changes over this extended period. The more recent sales (Index 1, 2 & 3) provide a narrower range of $166,000 per acre to $262,500 per acre.

Index 6 is the pending sale of a large parcel of employment land located on the fringe of the downtown core. This site has good exposure to a four-lane road and appears to possibly have some alternate development potential. Following an adjustment for superior exposure this sale indicates a rate of $231,000 per acre.

Index 7 is a small industrial parcel located centrally within Thunder Bay. The site is forested and required greater site works. Once adjusted this sale indicates a rate of $183,300 per acre.

Index 8 is the sale of a parcel of prestige industrial land located to the north of the subject study area. This site required clearing and greater site works. Once adjusted the sale indicates a rate of $215,600 per acre.

9.4 Direct Comparison Approach Conclusions

The selected comparable sales provide an adjusted range of $133,000 to $262,500 per acre. As noted the more recent neighbourhood sales provide a range of $166,000 to $262,500 per acre. The upper end of this range reflects the sale of a small site that was purchased by a nearby industrial tenant. It is our understanding that the purchaser was somewhat motivated and we would expect a benchmark rate for the subject location below this indication. The additional sales from outside the neighbourhood appear to support the indications provided by Index 1 to 3.

Considering the available sales data, it appears that industrial lands in the subject neighbourhood are trading in the general range of $180,000 to $240,000 per acre with upward pressure experienced in the past year. This appears to be stronger than observed in past years but is supported by the available market data. As such it is our opinion that a benchmark range closer to the upper end of the identified narrowed range is appropriate.

Therefore, we conclude a Benchmark Value for 1 to 2-acre industrial sites within the identified study area that are cleared and roughly graded of $210,000 to $240,000 per acre.

Industrial Land Benchmark Conclusion $210,000 to $240,000 per acre*

<u>*Reflects 1 to 2-acre industrial sites within the identified study area that are cleared and roughly graded.</u>

- Exposure Time

Exposure Time may be defined as: "The estimated length of time the property interest being appraised would have been offered on the market prior to the hypothetical consummation of a sale at market value on the effective date of the appraisal; a retrospective estimate based upon an analysis of past events assuming a competitive and open market." Exposure time is a function of price, time and use, not an isolated opinion of time alone. This is a retrospective estimate based upon an analysis of past events assuming a competitive and open market. It is always presumed to have preceded the effective date of the appraisal.

If competitively marketed, it is estimated that an exposure time of 3-12 months prior to the effective date of valuation would have been required to sell the subject property at the appraised market value.

9.5 *Final Conclusions / Reconciliation:*

- There are few available industrial sites in the desired subject site size range. The preceding identifies two options that appear to meet the criteria and a number of additional options that may not meet all the requirements but were considered note worthy.
- Available existing facilities are very limited in the required size range. We have identified two options but note that these do not appear to meet a number of requirements.
- We conclude a Benchmark Value for 1 to 2-acre industrial sites within the identified Beaverhall study area that are cleared and roughly graded of $210,000 to $240,000 per acre.

10.0 Summary Of Qualifications

Peter Spivey, B.Sc., AACI, P.App

Peter Spivey obtained his honours degree in biology with a minor in geography from the University of Guelph. Upon completion of his university degree, Peter Spivey entered the appraisal field and achieved his AACI (Accredited Appraiser Canadian Institute) designation in 2009.

RELATED WORK HISTORY

2006 – Present	Andrew, Thompson and Associates Ltd.

QUALIFICATIONS

AACI	Accredited Appraiser Canadian Institute This designates a fully accredited membership in the Institute and indicates a high level of competence in a wide range of real estate appraisal.
B.Sc.	Bachelor of Science • Honours Marine and Freshwater Biology Major (University of Guelph) • Geography Minor (University of Guelph)

CERTIFICATES AND COURSES

UBC - Real Estate Appraisal Course Stream (15 Courses)

Completion of the Eco Gift Seminar

OTHER ACHIEVEMENTS

Director, Ontario Expropriation Association.

VALUATION EXPERIENCE

Land	Residential Subdivision; Industrial Subdivisions; Rights of Way; Easements; Highway Widenings; Institutional Sites; Waterfront; Recreation Lands; Agricultural, Wood Lot, Escarpment Lands, etc.
Commercial	Downtown; Strip Plaza; Special Use; Freestanding Office Buildings; Converted Dwellings; Restaurants; Service Stations, etc.
Institutional	Airports; Federal; Provincial and Municipal Assets; School Sites; Utility Easements and Right of Ways; Utility Buildings; Transportation Facilities; Landfill Sites; Transmission Tower Sites; Well and Water Tower Sites, etc.
Agricultural	Hobby Farms; Land
Unique	Large Tracts; Large Institutional Buildings; Education Development Charges.
Consulting	Expropriation; Peer Review; Education Development Charges; Alternative – Valuations
Government Consulting	Road Widening and Easement Projects; Sale of Municipal or Surplus Land; Land Acquisition; Conservation Easements, Eco Gift Valuations, Environmental Acquisition's, etc.

11.0 Assumptions, Limiting Conditions, Disclaimers And Limitations Of Liabilities

The certification that appears in this report is subject to compliance with the Personal Information and Electronics Documents Act (PIPEDA), Canadian Uniform Standards of Professional Appraisal Practice ("CUSPAP") and the following conditions:

1. This report is prepared only for the client and authorized users specifically identified in this report and only for the specific use identified herein. No other person may rely on this report or any part of this report without first obtaining consent from the client and written authorization from the authors. Liability is expressly denied to any other person and, accordingly, no responsibility is accepted for any damage suffered by any other person as a result of decisions made or actions taken based on this report. Liability is expressly denied for any unauthorized user or for anyone who uses this report for any use not specifically identified in this report. Payment of the appraisal fee has no effect on liability. Reliance on this report without authorization or for an unauthorized use is unreasonable.

2. Because market conditions, including economic, social and political factors, may change rapidly and, on occasion, without warning, this report cannot be relied upon as of any date other than the effective date specified in this report unless specifically authorized by the author(s).

3. The author will not be responsible for matters of a legal nature that affect either the property being appraised or the title to it. The property is appraised on the basis of it being under responsible ownership. No registry office search has been performed and the author assumes that the title is good and marketable and free and clear of all encumbrances. Matters of a legal nature, including confirming who holds legal title to the appraised property or any portion of the appraised property, are outside the scope of work and expertise of the appraiser. Any information regarding the identity of a property's owner or identifying the property owned by the listed client and/or applicant provided by the appraiser is for informational purposes only and any reliance on such information is unreasonable. Any information provided by the appraiser does not constitute any title confirmation. Any information provided does not negate the need to retain a real estate lawyer, surveyor or other appropriate experts to verify matters of ownership and/or title.

4. Verification of compliance with governmental regulations, bylaws or statutes is outside the scope of work and expertise of the appraiser. Any information provided by the appraiser is for informational purposes only and any reliance is unreasonable. Any information provided by the appraiser does not negate the need to retain an appropriately qualified professional to determine government regulation compliance.

5. No survey of the property has been made. Any sketch in this report shows approximate dimensions and is included only to assist the reader of this report in visualizing the property. It is unreasonable to rely on this report as an alternative to a survey, and an accredited surveyor ought to be retained for such matters.

6. This report is completed on the basis that testimony or appearance in court concerning this report is not required unless specific arrangements to do so have been made beforehand. Such arrangements will include, but not necessarily be limited to: adequate time to review the report and related data, and the provision of appropriate compensation.

7. Unless otherwise stated in this report, the author has no knowledge of any hidden or unapparent conditions (including, but not limited to: its soils, physical structure, mechanical or other operating systems, foundation, etc.) of/on the subject property or of/on a neighbouring property that could affect the value of the subject property. It has been assumed that there are no such conditions. Any such conditions that were visibly apparent at the time of inspection or that became apparent during the normal research involved in completing the report have been noted in the report. This report should not be construed as an environmental audit or detailed property condition report, as such reporting is beyond the scope of this report and/or the qualifications of the author. The author makes no guarantees or warranties, express or implied, regarding the condition of the property, and will not be responsible for any such conditions that do exist or for any engineering or testing that might be required to discover whether such conditions exist. The bearing capacity of the soil is assumed to be adequate.

8. The author is not qualified to comment on detrimental environmental, chemical or biological conditions that may affect the market value of the property appraised, including but not limited to pollution or contamination of land, buildings, water, groundwater or air which may include but are not limited to moulds and mildews or the conditions that may give rise to either. Any such conditions that were visibly apparent at the time of inspection or that became apparent during the normal research involved in completing the report have been noted in the report. It is an assumption of this report that the property complies with all regulatory requirements concerning environmental, chemical and biological matters, and it is assumed that the property is free of any detrimental environmental, chemical legal and biological conditions that may affect the market value of the property appraised. If a party relying on this report requires information or an assessment of detrimental environmental, chemical or biological conditions that may impact the value conclusion herein, that party is advised to retain an expert qualified in such matters. The author expressly denies any legal liability related to the effect of detrimental environmental, chemical or biological matters on the market value of the property.

9. The analyses set out in this report relied on written and verbal information obtained from a variety of sources the author considered reliable. Unless otherwise stated herein, the author did not verify client-supplied information, which the author believed to be correct.

10. The term “inspection” refers to observation only as defined by CUSPAP and reporting of the general material finishing and conditions observed for the purposes of a standard appraisal inspection. The inspection scope of work includes the identification of marketable characteristics/amenities offered for comparison and valuation purposes only.

11. The opinions of value and other conclusions contained herein assume satisfactory completion of any work remaining to be completed in a good and workmanlike manner. Further inspection may be required to confirm completion of such work. The author has not confirmed that all mandatory building inspections have been completed to date, nor has the availability/issuance of an occupancy permit been confirmed. The author has not evaluated the quality of construction, workmanship or materials. It should be clearly understood that this visual inspection does not imply compliance with any building code requirements as this is beyond the professional expertise of the author.

12. The contents of this report are confidential and will not be disclosed by the author to any party except as provided for by the provisions of the CUSPAP and/or when properly entered into evidence of a duly qualified judicial or quasi-judicial body. The author acknowledges that the information collected herein is personal and confidential and shall not use or disclose the contents of this report except as provided for in the provisions of the CUSPAP and in accordance with the author’s privacy policy. The client agrees that in accepting this report, it shall maintain the confidentiality and privacy of any personal information contained herein and shall comply in all material respects with the contents of the author's privacy policy and in accordance with the PIPEDA.

13. The author has agreed to enter into the assignment as requested by the client named in this report for the use specified by the client, which is stated in this report. The client has agreed that the performance of this report and the format are appropriate for the intended use.

14. This report, its content and all attachments/addendums and their content are the property of the author. The client, authorized users and any appraisal facilitator are prohibited, strictly forbidden, and no permission is expressly or implicitly granted or deemed to be granted, to modify, alter, merge, publish (in whole or in part) screen scrape, database scrape, exploit, reproduce, decompile, reassemble or participate in any other activity intended to separate, collect, store, reorganize, scan, copy, manipulate electronically, digitally, manually or by any other means whatsoever this appraisal report, addendum, all attachments and the data contained within for any commercial, or other, use.

15. If transmitted electronically, this report will have been digitally signed and secured with personal passwords to lock the appraisal file. Due to the possibility of digital modification, only originally signed reports and those reports sent directly by the author can be reasonably relied upon.

16. This report form is the property of the Appraisal Institute of Canada (AIC) and for use only by AIC members in good standing. Use by any other person is a violation of AIC copyright.

17. Where the intended use of this report is for financing or mortgage lending or mortgage insurance, it is a condition of reliance on this report that the authorized user has or will conduct lending, underwriting and insurance underwriting and rigorous due diligence in accordance with the standards of a reasonable and prudent lender or insurer, including but not limited to ensuring the borrower's demonstrated willingness and capacity to service his/her debt obligations on a timely basis, and to conduct loan underwriting or insuring due diligence similar to the standards set out by the Office of the Superintendent of Financial Institutions (OSFI), even when not otherwise required by law. Liability is expressly denied to those that do not meet this condition. Any reliance on this report without satisfaction of this condition is unreasonable.

18. All copyright is reserved to the author and this report is considered confidential by the author and the client. Possession of this report, or a copy thereof, does not carry with it the right to reproduction or publication in any manner, in whole or in part, nor may it be disclosed, quoted from or referred to in any manner, in whole or in part, without prior written consent and approval of the author as to the purpose, form and content of any such disclosure, quotation or reference. Without limiting the generality of the foregoing, neither all nor any part of the contents of this report shall be disseminated or otherwise conveyed to the public in any manner whatsoever or through any media whatsoever or disclosed, quoted from or referred to in any report, financial statement, prospectus, or offering memorandum of the client, or in any documents filed with any governmental agency without the prior written consent and approval of the author as to the purpose, form and content of such dissemination, disclosure, quotation or reference. This is subject only to confidential review by the Appraisal Institute of Canada as provided in the Canadian Uniform Standards of Professional Appraisal Practice.

12.0 Certificate Of The Appraiser

I certify that, to the best of my knowledge and belief that:

1. The statements of fact contained in this report are true and correct;
2. The reported analyses, opinions and conclusions are limited only by the reported assumptions and limiting conditions and are my impartial and unbiased professional analyses, opinions and conclusions;
3. I have no past, present or prospective interest in the property that is the subject of this report and no personal and/or professional interest or conflict with respect to the parties involved with this assignment.
4. I have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment;
5. My engagement in and compensation is not contingent upon developing or reporting predetermined results, the amount of value estimate, a conclusion favouring the client, or the occurrence of a subsequent event.
6. My analyses, opinions and conclusions were developed, and this report has been prepared, in conformity with the CUSPAP.
7. I have the knowledge and experience to complete this assignment competently, and where applicable this report is co-signed in compliance with CUSPAP;
8. Except as herein disclosed, no one has provided significant professional assistance to the person(s) signing this report;
9. As of the date of this report the undersigned has fulfilled the requirements of the AIC's Continuing Professional Development Program;
10. The undersigned is (are all) members in good standing of the Appraisal Institute of Canada.

Final Conclusions

- There are few available industrial sites in the desired subject site size range. The preceding identifies two options that appear to meet the criteria and a number of additional options that may not meet all the requirements but were considered note worthy.
- Available existing facilities are very limited in the required size range. We have identified two options but note that these do not appear to meet a number of requirements.
- We conclude a Benchmark Value for 1 to 2-acre industrial sites within the identified Beaverhall study area that are cleared and roughly graded of $210,000 to $240,000 per acre.

AIC Appraiser

DRAFT

Signature: ____________________
Name: Peter Spivey, B.Sc, AACI, P.App, 904444
Date of Report:
Personally, Inspected the Subject Property Yes
Date of Inspection: July 22, 2021
Source of digital signature security: Password Protected PDF Document

Note: For this appraisal to be valid, an original or a digital signature is required and the document is to be password protected from modification.

13.0 Addenda

13.1 Detailed Land Sales and Sales Location Maps

13.1 Land Sales Map and Detailed Write Ups

Figure 7 Source: Google Earth

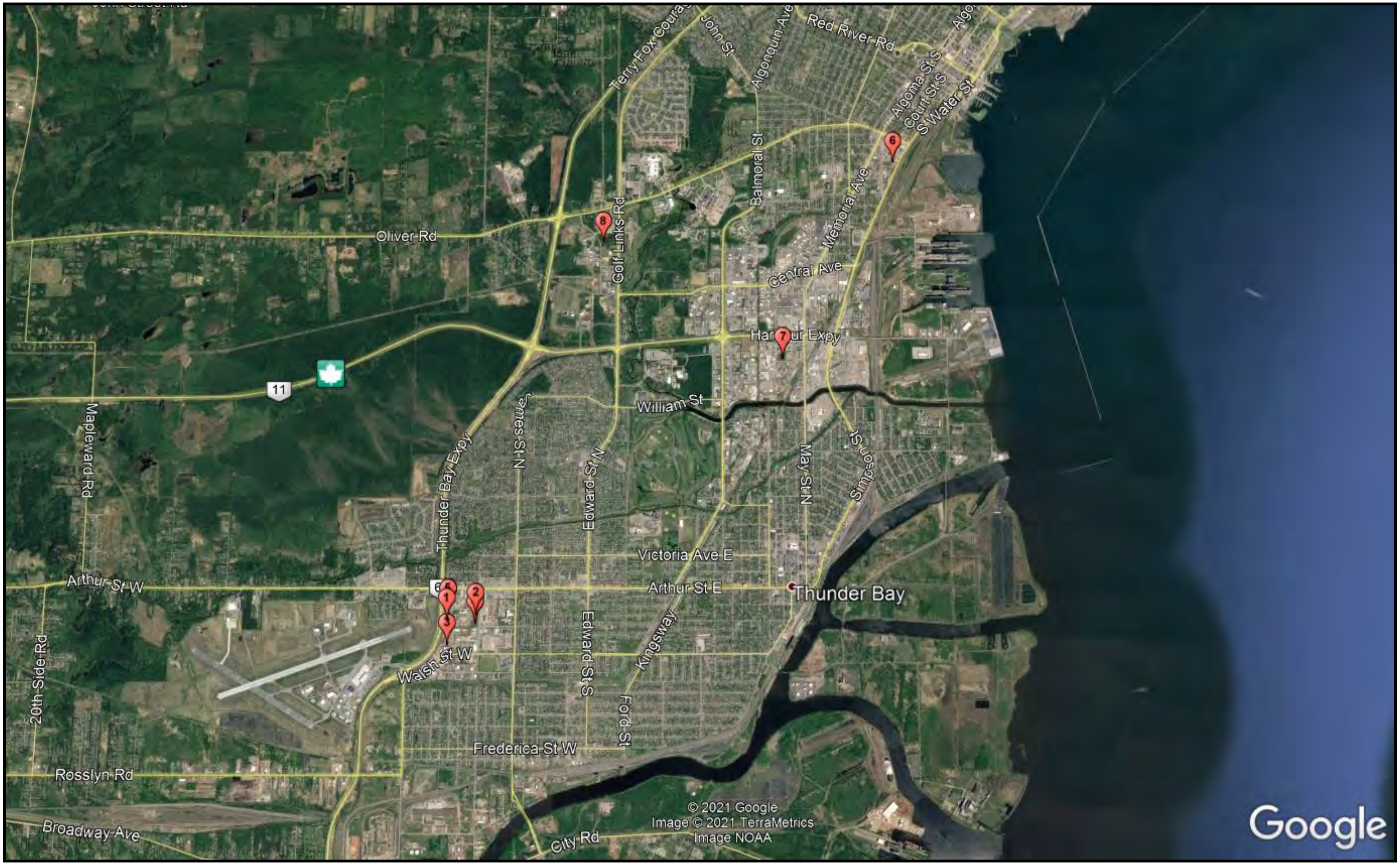


Figure 8 Source: Google Earth

COMPARABLE#: 1

Address: 645 Beaverhall Place
Municipality: Thunder Bay
Community: n/a
Sale Price: $325,000.00
Sale $/Unit: $179,558 per acre
Sale Date: Nov 26, 2020
Pin # 620430091
Vendor 948825 Ontario Inc.
Purchaser Sparcon Construction Inc.
Roll Number 580404020102500

SITE INFORMATION

Lot Area: 1.81 acres **Frontage:** 322
Location: Interior **Services:** Full

Zoning- IN2- Medium Industrial
OP: Industrial

Legal Description Lot 17 Plan W796,Neebing; City of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 2

Address:	600 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$250,000.00
Sale $/Unit:	$160,256 per acre
Sale Date:	Dec 04, 2020
Pin #	620430043
Vendor	Pepco Tbay Inc.
Purchaser	2786341 Ontario Ltd.
Roll Number	580404020103900

SITE INFORMATION

Lot Area:	1.56	acres	**Frontage:**	170	**Zoning**	ID2- Medium Industrial
Location:	Corner		**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 6 on Plan W796, Neebing Part 1, 55R10259; in the city of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is located at the intersection of Beaverhall Place and Mountdaye Avenue. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 3

Address:	685 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$300,000.00
Sale $/Unit:	$348,837 per acre
Sale Date:	Jun 25, 2021
Pin #	620430053
Vendor	Grant Equipment Corp.
Purchaser	539804 Ontario Inc.
Roll Number	580404020113105

SITE INFORMATION

Lot Area:	0.86 acres	**Frontage:**	127	**Zoning**	IN1- Light Industrial
Location:	Interior	**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 20 on Plan W796, Neebing; Part Stanley Ave. on Plan QW796 Neebing, Closed by TBR413183, Part 1 and 2 on 55R7794; Subject to Right in TBR221127; in the city of Thunder Bay

Parcel of a small parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site was reportedly acquired by a nearby user to develop an industrial facility. This site was cleared and generally level and used as a storage yard at the time of the sale. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 4

Address:	625 Mountdale Ave.
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$167,000.00
Sale $/Unit:	$115,172 per acre
Sale Date:	May 04, 2016
Pin #	620430089
Vendor	Not Available
Purchaser	Mahon Electric Company Limitedà
Roll Number	580404020104000

SITE INFORMATION

Lot Area:	1.45	acres	**Frontage:**	244	**Zoning**	ID2- Medium Industrial
Location:	Interior		**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 7 on Plan W796, Neebing, Parts 1 and 2 on Plan 55R14039, Subject to an Easement in Gross over Part 2 on Plan 55R14039 as in TY214023, in the city of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area), fronting the west side of Mountdale Avenue. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 5

Address:	625 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$300,000.00
Sale $/Unit:	$177,515 per acre
Sale Date:	Sep 09, 2014
Pin #	620430049
Vendor	Royal Host GP Inc.
Purchaser	1383793 Ontario Inc.
Roll Number	580404020102600

SITE INFORMATION

Lot Area:	1.69	acres	**Frontage:**	300	**Zoning**	C3- Highway Com.
Location:	Interior		**Services:**	Full	**OP:**	Commercial

Legal Description Part of Lot 16 on Plan W796 Neebing as in TBR341227 as ammended by TBR394415 except the Easement therein; Part of Block A on Plan 864 Neebing, Part 1 and 2 on 55R8957; Subject to TBR341227 and OFW54411; in the city of Thunder Bay

Parcel of commercial designated land located in a primarily industrial area known as the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is located adjoining an older motel and formerly formed part of the parking lot. Although designated commercial some opportunity may be present for conversion to an industrial type use. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 6

Address:	295 Court Street S.
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$1,150,000.00
Sale $/Unit:	$330,460 per acre
Sale Date:	Jul 30, 2021
Pin #	621260078 & 621260074
Vendor	Arnone Transport Limited
Purchaser	Not Yet Registered
Roll Number	580401003503600 & *

SITE INFORMATION

Lot Area:	3.48	acres	**Frontage:**	409	**Zoning**	IN2- Medium Com.
Location:	Interior		**Services:**	Full	**OP:**	Industrial

Legal Description Part Lot 1-4 Block 35on Plan 147 McIntyre; Part Lot 49-51, 54-55, 57 Plan 572 McIntyre Part 3 & 4, 55R10246; T/W TBR413511; Subject to PTA141390; Subject toTBR284105, TBR398827; in the city of Thunder Bay & **

Sale of a good quality parcel of employment land located centrally in Thunder Bay. This site had exposure to Water Street, a 4 lane arterial road and is on the fringe of the downtown core. The site is cleared and generally level and appears to have been utilized for trailer parking / storage.

MLS Sale Date: 06/25/2021

* 580401003500910
**Lots 73,75,77,79 & Part of Lots 54,56,58,80,81,82 & Part Inchiquin Street Closed by TBR163865, on Plan 572 AND Part Lots 2,3,4 & Part Lane Closed by TBR163865 & Part 0.30 Reserve Block 35 on Plan 147 Being Parts 1 & 5 55R12031 & Parts 7 & 8 55R10246 ; Thunder Bay ; Subject to Easements TBR438725,F128620,F132236 on Part 5 Plan 55R12031; in the city of Thunder Bay.

COMPARABLE#: 7

Address:	0 Dunlop Street
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$151,000.00
Sale $/Unit:	$138,532 per acre
Sale Date:	Mar 18, 2021
Pin #	620790552 & 620790507
Vendor	Not Available
Purchaser	1648822 Ontario Ltd.
Roll Number	580401003732800

SITE INFORMATION

Lot Area:	1.09	acres	**Frontage:**	200	**Zoning**	IN2- Medium Ind.
Location:	Interior		**Services:**	Full	**OP:**	Commercial

Legal Description Lots 132-136 on Plan M52 and Part Brandon Avenue, Plan M52 Closed by LT136601, Part 5 on 55R14780; in the city of Thunder Bay & Part Brandon Avenue on Plan M52 Closed by LT136601, Part 4 on 55R14780; in the city of Thunder Bay

Small parcel of industrial land located centrally within Thunder Bay. This site was treed and required clearing and some fill to allow for development.

COMPARABLE#: 8

Address:	224 Burwood Rd
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$399,900.00
Sale $/Unit:	$141,307 per acre
Sale Date:	Jan 15, 2020
Pin #	621170020
Vendor	Daniel Clara
Purchaser	Reliable Northern Developments Ltd.
Roll Number	580402010108000

SITE INFORMATION

Lot Area:	2.83	acres	**Frontage:**	248	**Zoning**	IN6- Prestige Ind.
Location:	Interior		**Services:**	Full in Area	**OP:**	Industrial

Legal Description Part of Lot 19 on Plan 760 McIntyre as in TBR215580; city of Thunder Bay

Parcel of industrial land located in the central portion of Thunder Bay, slightly east of Highway 17. The site was forested and required clearing and some grading / fill works. It is our understanding that full municipal services are in the area.

Appendix B

Report on Customer Service Research 2021 Results

Report on Customer Service Research 2021 Results

Prepared for Hydro One Remote Communities

January 2022

Viewpoints Research
Winnipeg, Manitoba
(204) 988-9253
www.viewpoints.ca

TABLE OF CONTENTS

EXECUTIVE SUMMARY

On behalf of Hydro One Remote Communities (Hydro One Remotes), Viewpoints Research conducted a telephone survey of 184 of its residential, business and government-supported organization customers from December 13th, 2021 to January 4th, 2022.

Where possible, the survey tracks findings from nine previous waves of customer surveys conducted approximately every two years since 2003.

Conclusions

- More customers feel their **electrical service is as reliable** as it has been, fewer think it is improved.
- **Customer satisfaction is at its highest recorded level** because there are **few problems** and they **have electricity when needed** and the **service is reliable.**
- There were **few dissatisfied customers** but, among them, the **cost of service** was cited most of as the reason for their dissatisfaction.
- A majority of customers did not offer a suggestion to improve services. Others proposed Hydro One **improve service** or **lower costs.**
- Most customers believe their **bills are always or usually correct**
- The perception customers' **rates are the same or lower** than the rest of Ontario continues to rise.
- A majority of customers favour paying their bills using **internet or telephone banking**, a **credit card** or a **banking app**.
- Customers' top choices for receiving communication from Hydro One Remotes are **posters**, **newsletters** or **social media**.
- More than three in four respondents said it would be helpful or very helpful to have a customer service representative with whom they could **discuss their Hydro bill in their Indigenous language**.
- In the past year, customers contacted Hydro One Remotes to **discuss their bill**, because the **power was out** or because they **needed information**. Almost all customers who called Hydro One Remotes were **satisfied** with their contact, among the highest overall satisfaction levels recorded.

Reliability of Electrical Service

Three in four customers interviewed feel that, in the past few years, the reliability of their electrical service has stayed about the same (77%), while 17% indicated it has improved and just 3% said it has worsened.

Overall Satisfaction with Service

At 96%, overall satisfaction with the electricity service customers receive from Hydro One Remotes is at the second highest level recorded since tracking began. Very satisfied responses are also at their highest level since tracking began. Just 2% of customers are dissatisfied with their service.

Among those who are satisfied with their electrical service*, no problems/things are fine* was mentioned most often by respondents as the reason for their satisfaction (31%), followed by the assertion that *electricity was there when needed* (25%) and *reliability has improved/goes of less/comes back sooner* (19%).

There were just six dissatisfied customers in this research. Four of these feel the services is *expensive/costs too much in general* (67%), one each mentioned it is *unreliable*, *appliances burn out/don't work/brownouts/poor quality of electricity* and not being able to *plug in many/large appliances*, finding *billing confusing* and feeling *billing is not fair/discriminates* (each 17%).

How to Improve Service

Asked the most important thing Hydro One Remotes should be doing to improve service for them and their community, seven in ten respondents did not offer a response (71%). The most frequent suggestions were to improve services and lower costs (each 5%), and upgrade equipment, advise about financial assistance programs, and provide information sessions (each 3%). About 2% each mentioned fewer outages and provide translation.

Billing Accuracy

More than eight in ten respondents indicated they are the person who usually (81%) or sometimes pays their Hydro bill (4%), while 15% indicated they are not the person who usually pays it.

Among those who sometimes or usually pay their Hydro bill, eight in ten asserted it is always (33%) or usually correct (50%), while 3% feel it is not very often or never correct.

Rates vs. Rest of Ontario

The perception their rates are the same or lower than the rest of Ontario continues to increase, with six in ten Hydro One Remotes customers believing their Hydro rates are either the same as the rest of Ontario (38%) or lower (13%). About 23% of customers believe their rates are higher and 26% are unsure.

Preferred Bill Payment Method

More than one third of customers prefer to pay their Hydro bills over the internet or telebanking (36%), 19% opted for credit card payments and 15% selected the banking app on their phone.

Preferred Method of Communication by Hydro One Remotes

Almost half of respondents prefer Hydro One Remotes communicate with them using either posters in the community (21%) or newsletters (25%). One in eight prefer communication through Facebook or other social media (13%).

Customer Service in Respondents' Indigenous Language

More than three in four respondents said it would be helpful (47%) or very helpful (30%) to have a customer service representative with whom they could discuss their Hydro bill in their Indigenous language. One in eight said this would not be very helpful (16%).

Contact with Hydro One Remotes

Two thirds of customers said they did not contact Hydro One Remotes in the past year (64%). As in previous years, the most common reason customers contacted the utility was to discuss their bill (16%). Other reasons for contact included because the power is out (10%), and needing information (8%).

Among customers who called Hydro One Remotes, respondents very satisfied with how the utility handled their contact reached its highest level yet recorded (57%). When very and somewhat satisfied responses were combined, this years' results fell to second place overall (91%). Just 4% of customers said they were dissatisfied with their contact.

Perceptions of Hydro One Remotes

This research tested customers' agreement with three statements related to customer service, to explore customers' experiences and perceptions in key service areas. Hydro One Remotes scored best at *dealing with emergencies* (91% agree overall) and *staff being polite and friendly* (73%). Customers were less likely to agree that *when they call the Hydro One office someone usually answers quickly,* though more than half agreed (57%).

Number of Calls Needed for Resolution

More than half of customers said their question or concern was resolved the first time they called Hydro One Remotes (51%), while 15% said an additional call was required and 34% were unsure. These unsure responses suggest some respondents did not call the Hydro One office.

Awareness of Local Operators & Meter Readers

More than one third of customers know who both their operator and their meter reader is (29%, down 5 points since 2019), while slightly more know one but not the other (36%). A similar number know neither their meter reader nor their operator (35%).

Contact During Outages

A majority of customers do not call anyone when there is an outage (60%). About two in ten call either the band office (9%) or the phone number on their bill (9%). Fewer customers call the meter reader (7%), the emergency hotline (5%) or the operator (5%).

Awareness of Hydro One Programs

Awareness of the Ontario Electricity Support Program (OESP) remains high at 51%. Half that number is aware of the Low-Income Emergency Assistance Program (LEAP) (24%).

GOALS & METHODOLOGY

Goals

On behalf of Hydro One Remote Communities (Hydro One Remotes), Viewpoints Research conducted telephone interviews with the utility's residential, commercial and government-supported organization customers from December 13th, 2021 to January 4th, 2022. Many of the questions included in this survey have been tracked from earlier customer surveys administered about every two years since 2003. The research explored the following:

- Customers' views on the accuracy of their bills,
- Recent contact with Hydro One Remotes, and satisfaction with that contact,
- General perceptions of Hydro One Remotes' responsiveness and customer service,
- Customers' preferred method of bill payment,
- Awareness of local Hydro One Remotes' staff,
- Perceptions of the reliability of their Hydro service,
- Contacts in the event of a Hydro outage,
- Perceptions of their Hydro rates compared to elsewhere in Ontario,
- Awareness of electricity-related programs,
- Preferred method of communication from Hydro One Remotes, including have a billing person who could discuss customers' bills in their Indigenous language,
- Ways Hydro One Remotes could improve service to customers and communities, and
- Overall satisfaction with the electricity service provided by Hydro One Remotes, and reasons for their satisfaction or dissatisfaction.

Methodology

In the current wave of research, as in 2019, Hydro One Remotes provided Viewpoints with de-identified customer phone numbers in order to contact residents to participate in the survey. In previous waves of research, sample was drawn from listed and unlisted telephone numbers in the Hydro One Remotes' service area. This change in sampling should be kept in mind when considering differences between the last two waves of research and earlier results.

Hydro One Remote Communities has about 4,200 customers in 22 communities, serving 15,000+ people. This year 184 customers were interviewed, including 164 residential customers, 19 business customers and 9 government-supported organizations. The survey has an overall confidence level of ±6.9%, 19 times out of 20.

The findings of this research were cross-tabulated by the following demographic and attitudinal variables:

- Community,
- Whether or not electricity is their main heat source,
- Type of service (residential, commercial or government-supported organization),
- Satisfaction with electrical service,
- Whether or not customers have contacted Hydro One Remotes in the past year,
- Gender, and
- Age.

Reporting

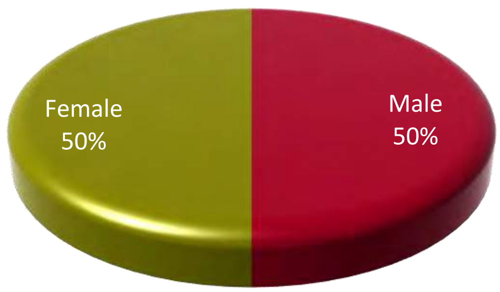
This report highlights the overall views and perceptions of Hydro One Remotes Communities' customers. Statistically significant differences between sub-groups of customers are noted in the report in a bulleted point. The report also compares the findings to results from nine previous waves of research conducted approximately every two years since 2003.

There are significant differences of opinion and experience among residents of the different communities served by Hydro One Remotes, however these results should be interpreted with caution since the number of respondents in most communities is very small. Generally, caution should be applied when considering differences among sub-groups with fewer than 100 respondents.

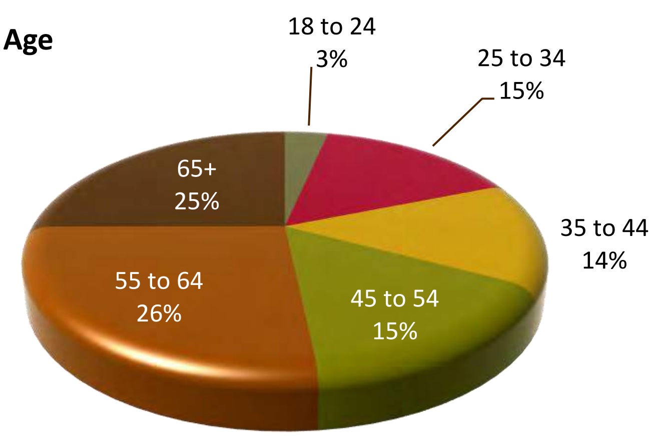
RESPONDENT PROFILE

The following charts provide an overview of respondents interviewed for this wave of research.

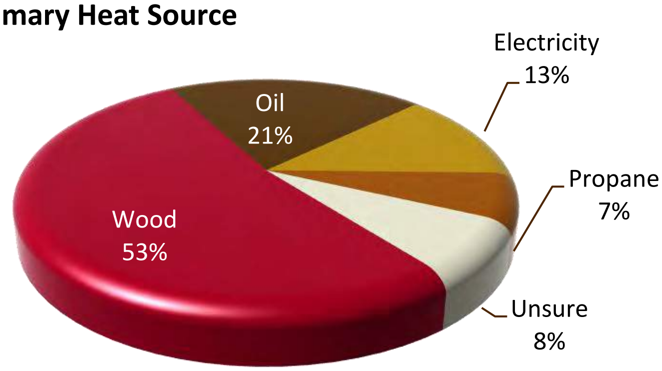
Gender

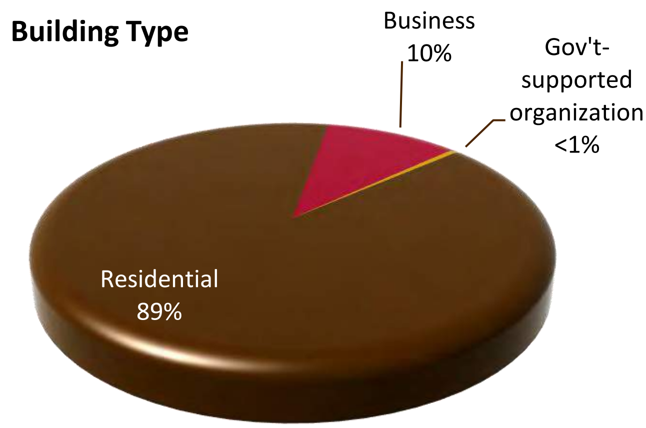


Age

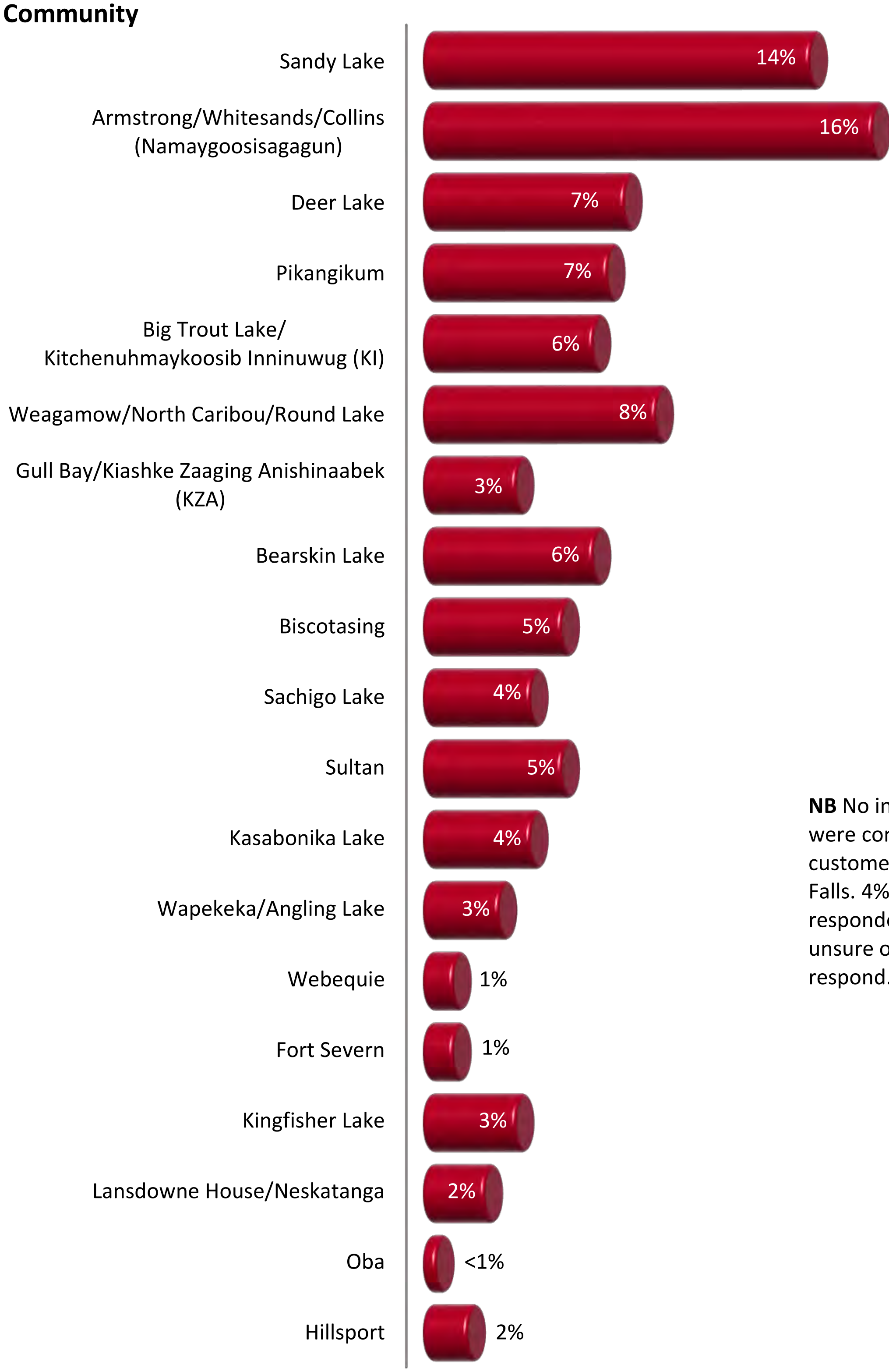


Primary Heat Source




Building Type
Business 10%
Gov't-supported organization <1%
Residential 89%

Community



NB No interviews were completed with customers in Marten Falls. 4% of respondents were unsure or declined to respond.

Respondents Over Time

The following table summarizes the demographic attributes of respondents in this research since 2003. The characteristics of participating customers has remained fairly constant over time, though respondents are getting older.

Respondents Over Time

Respondents	2021	2019	2017	2015	2013	2011	2009*	2007	2005	2003
Customer										
Home	**89%**	89%	98%	91%	82%	89%	87%	81%	82%	96%
Business	**10%**	7%	1%	4%	10%	5%	7%	6%	8%	2%
Gov't-funded	**<1%**	4%	<1%	6%	9%	6%	6%	13%	10%	2%
Age										
18 – 24 years	**3%**	5%	1%	7%	8%	6%	8%	13%	10%	13%
25 – 34 years	**15%**	7%	13%	15%	15%	17%	20%	26%	23%	22%
35 – 44 years	**14%**	15%	17%	12%	19%	19%	21%	24%	28%	26%
45 – 54 years	**15%**	22%	23%	23%	26%	21%	21%	20%	23%	21%
55 – 64 years	**26%**	26%	22%	22%	16%	22%	19%	11%	10%	11%
65+ years	**25%**	25%	23%	22%	15%	15%	11%	5%	4%	7%
Gender										
Men	**50%**	52%	57%	54%	50%	56%	60%	54%	56%	54%
Women	**50%**	48%	43%	46%	50%	44%	40%	46%	44%	46%

Tallies may not equal 100%. Customers who were unsure are not included.
*Research conducted in 2009/2010 is reported as 2009 in this document.

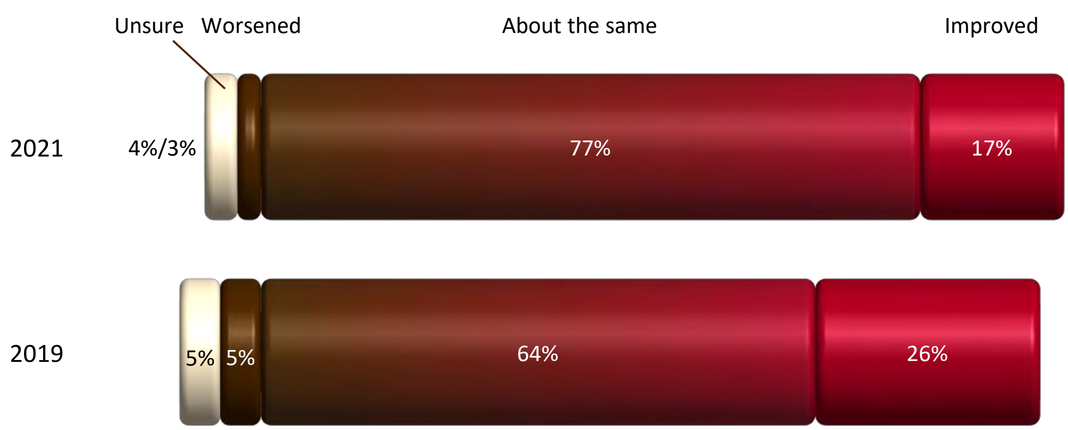
RESEARCH FINDINGS

Satisfaction with Electricity Service

Reliability of Electrical Service (Q14)

Three in four customers interviewed feel that, in the past few years, the reliability of their electrical service has stayed about the same (77%, up 13 points since 2019), while 17% indicated it has improved (down 9 points) and just 3% said it has worsened, down 2 points. Another 4% are unsure.

Chart 1: **Reliability of Electrical Service**

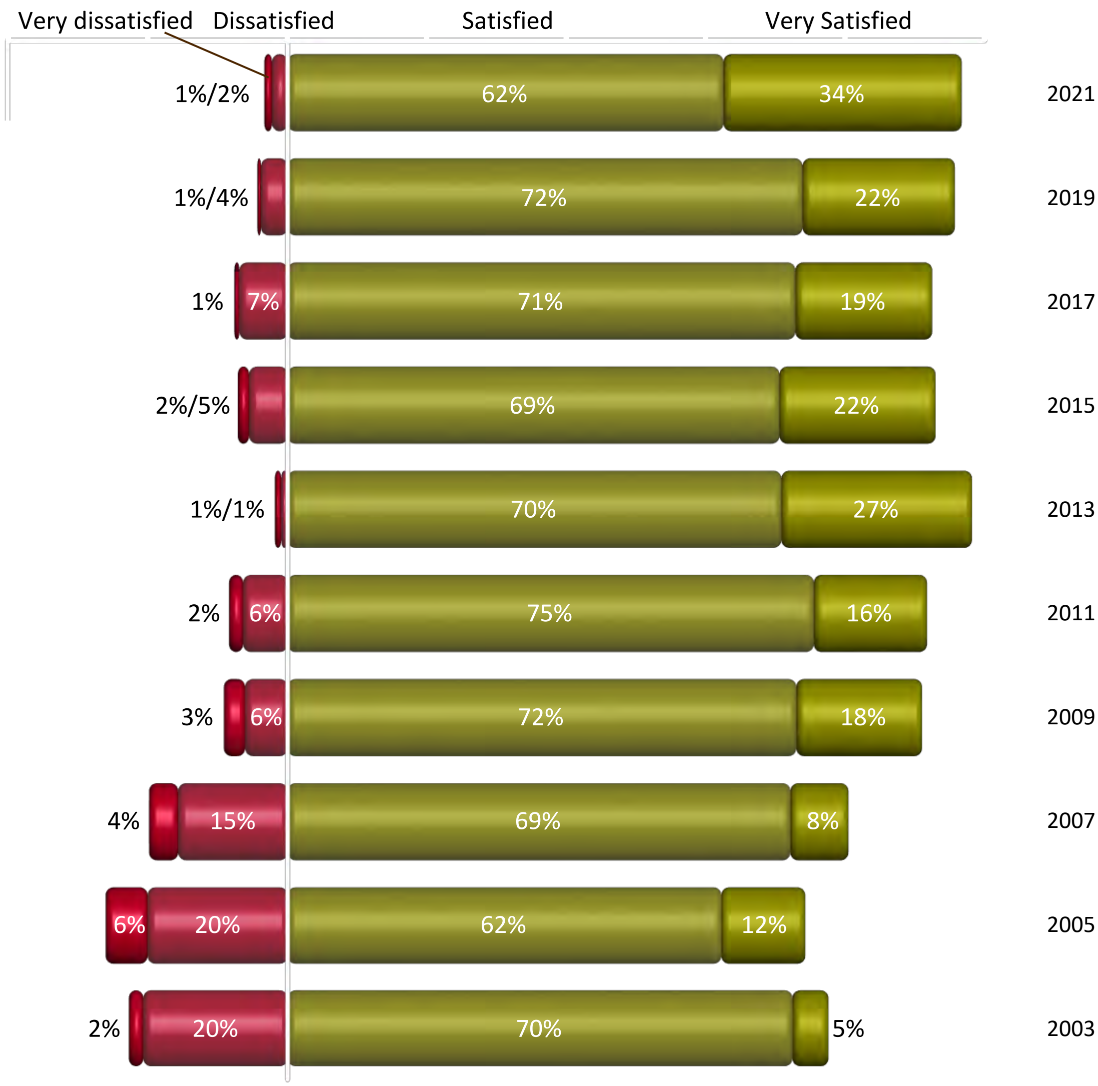


- Customers who have contacted Hydro in the past year are more likely to say the reliability of their electrical service has improved (22% vs. 15% customers who have not contacted Hydro in the past year) or worsened (8% vs. 0%). Customers who have not contacted Hydro are more likely to say their service has stayed about the same (82% vs. 68% contacted Hydro).

Overall Satisfaction with Service (Q22)

At 96%, overall satisfaction with the electricity service customers receive from Hydro One Remotes is at the second highest level recorded since tracking began, outpaced only by 2013 results of 97%, and 22 points ahead of the lowest satisfaction levels recorded in 2005 (74%). Very satisfied responses are at their highest level since tracking began, well above the previous high of 27% in 2013. Just 2% of customers are dissatisfied with their service and <1% indicated they are unsure.

Chart 2: **Satisfaction with Electricity Service**



- In communities with 9+ respondents, those most likely to be very satisfied with their electrical service live in Biscotasing (78%) and Sultan (67%), while those in Bearskin Lake (9%) and Deer Lake (15%) are least likely to be very satisfied.

Reasons for Customer Satisfaction (Q23)

Among those who are satisfied with their electrical service (n=177*), no problems/things are fine* was mentioned most often by respondents as the reason for their satisfaction (31%, up 8 points since 2019), followed by the assertion that *electricity was there when needed* (25%, up 2 points) and *reliability has improved/goes of less/comes back sooner* (19%, down 10 points).

A similar number mentioned *good/better service* (18%, up 4 points), while fewer said *rates are good/fair* (6%, down 5 points) or cited *customer service* as the reason for their satisfaction (5%, unchanged).

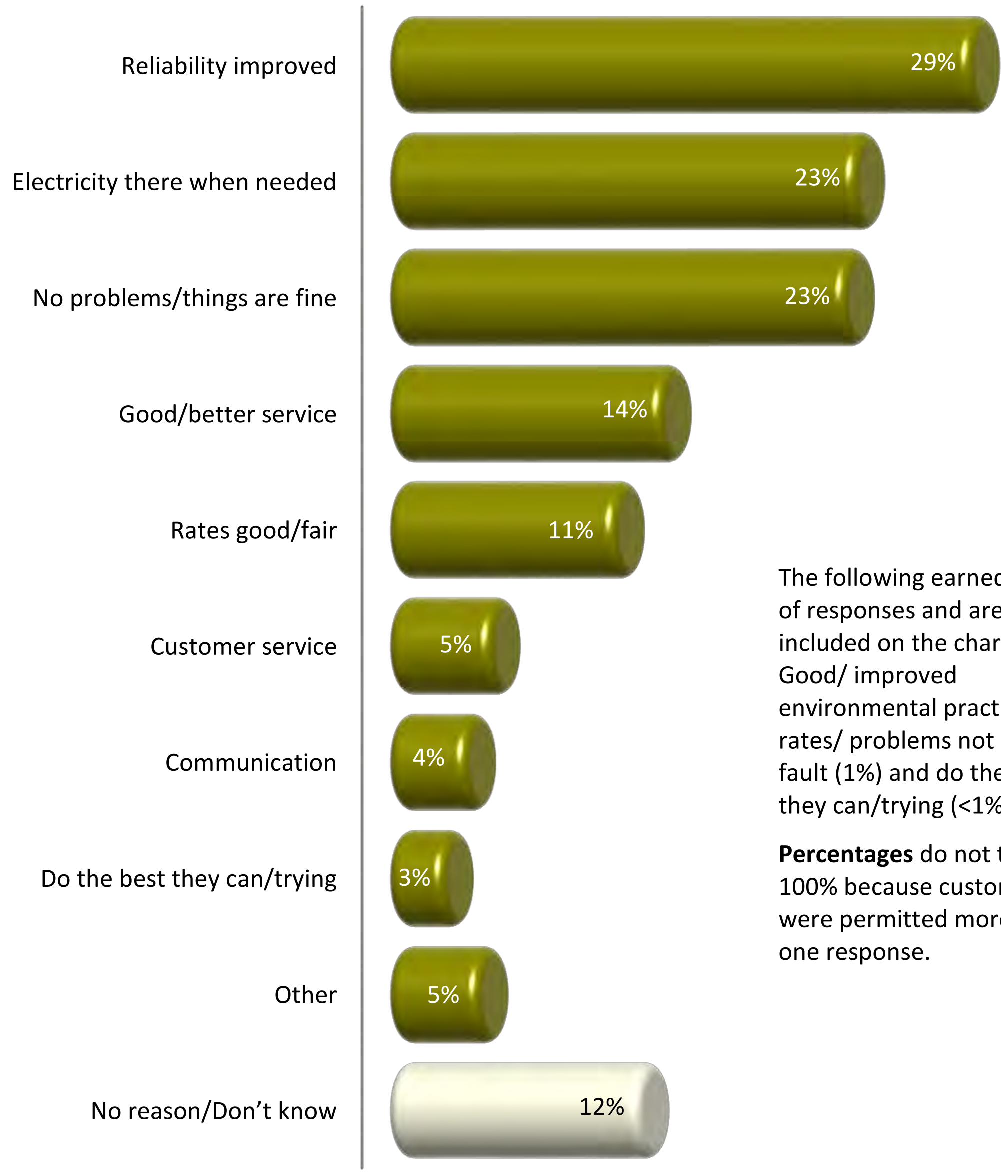
One in four respondents offered another reason or no reason, or were unsure how to respond to this question (24%).

Table 1 compares this year's results to past waves of research and Chart 3 displays the reasons for satisfaction mentioned by customers.

Table 1: **Reasons for Customer Satisfaction**

Reason	2021	2019	2017	2015	2013	2011	2009	2007	2005	2003
Electricity there when needed/no problems	**56%**	46%	71%	65%	51%	49%	40%	42%	43%	43%
Reliability has improved	**19%**	29%	12%	12%	17%	25%	20%	12%	10%	10%
Good/better service	**18%**	14%	14%	20%	15%	26%	18%	20%	19%	19%
Good/fair rates	**6%**	11%	5%	4%	6%	10%	5%	5%	6%	6%
Customer service	**5%**	5%	7%	10%	10%	11%	13%	3%	4%	4%
Company doing the best they can	**<1%**	3%	4%	4%	2%	6%	5%	3%	4%	4%
Rates/problems not their fault	**1%**	<1%	3%	1%	NA	NA	NA	NA	NA	NA
Environmental practices	**1%**	1%	<1%	0%	1%	2%	2%	<1%	1%	1%
No reason/other/ unsure	**24%**	17%	14%	12%	19%	10%	27%	26%	26%	26%

Chart 3: **Reason for Customer Satisfaction** (n=177)



The following earned ≤1% of responses and are not included on the chart: Good/ improved environmental practices, rates/ problems not their fault (1%) and do the best they can/trying (<1%).

Percentages do not total 100% because customers were permitted more than one response.

Reasons for Customer Dissatisfaction *(Q24)*

There were just six dissatisfied customers in this research. Four of these feel the services is *expensive/costs too much in general* (67%), one each mentioned it is *unreliable*, *appliances burn out/don't work/brownouts/poor quality of electricity* and not being able to *plug in many/large appliances*, finding *billing confusing* and feeling *billing is not fair/discriminates* (each 17%). One customer offered another reason (17%).

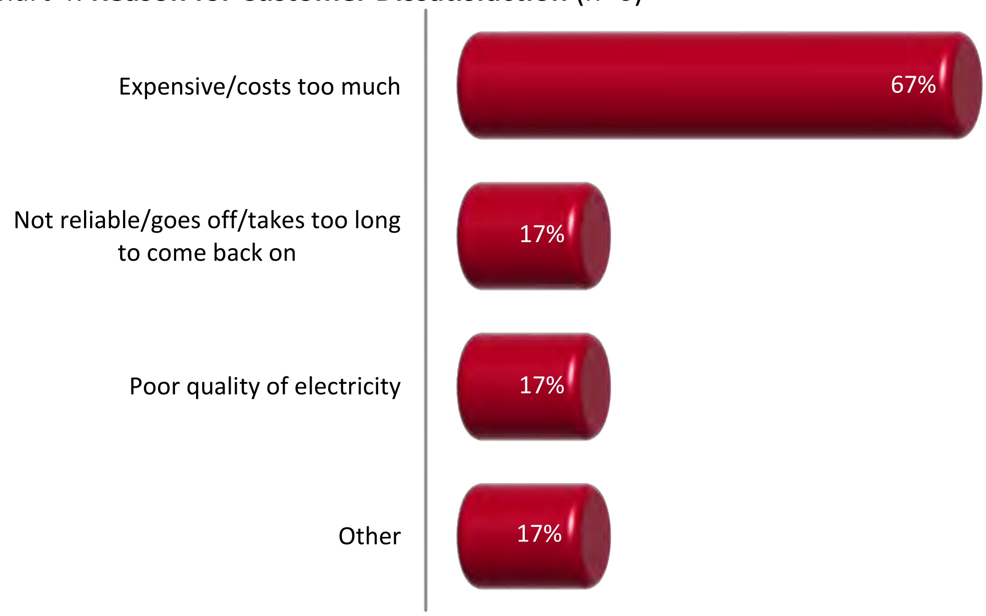
Table 2 compares this year's results to past waves of research and Chart 4 displays the reasons for dissatisfaction mentioned by customers.

Table 2: **Reasons for Customer Dissatisfaction**

Reasons	2021	2019	2017	2015	2013	2011	2009	2007	2005	2003
Rates										
Expensive/costs too much	**67%**	38%	73%	85%	50%	56%	48%	64%	73%	63%
Billing not fair/discriminatory	**0%**	13%	9%	NA	25%	8%	4%	9%	14%	13%
Billing confusing	**0%**	13%	9%	NA	25%	0%	4%	2%	10%	8%
Service Issues										
Not reliable	**17%**	25%	18%	31%	50%	20%	15%	22%	21%	23%
Poor quality electricity/ brownouts/problems with appliances	**17%**	13%	9%	8%	25%	4%	11%	5%	7%	21%
Other										
Don't like diesel/bad for the environment	**0%**	13%	18%	NA	50%	4%	0%	0%	1%	0%
Community/economy hurt by service/company	**0%**	0%	9%	NA	25%	0%	0%	2%	2%	2%
Don't like Hydro One	**NA**	NA	NA	NA	NA	0%	5%	5%	8%	3%
No reason/other	**17%**	25%	9%	23%	NA	8%	7%	7%	6%	2%

Percentages do not total 100% because customers were permitted more than one response.

Chart 4: **Reason for Customer Dissatisfaction** (n=6)



How to Improve Service (Q21)

Asked the most important thing Hydro One Remotes should be doing to improve service for them and their community, seven in ten respondents did not offer a response (71%). The most frequent suggestions were to improve services and lower costs (each 5%), and upgrade equipment, advise about financial assistance programs, and provide information sessions (each 3%). About 2% each mentioned fewer outages and provide translation.

Chart 5: **How to Improve Service**

Hydro Billing & Rates

Billing Accuracy (Qs 4 & 5)

More than eight in ten respondents indicated they are the person who usually (81%) or sometimes pays their Hydro bill (4%), while 15% indicated they are not the person who usually pays it.

Among those who sometimes or usually pay their Hydro bill (n=156), eight in ten assert that it is always correct (33%, up 1 point since 2019) or usually correct (50%, up 6 points since 2019), while 3% feel it is not very often or never correct and 14% are unsure.

The view that bills are generally accurate is at its second highest level since tracking began on this question (88%), though *always correct* responses are lower than those in 2013 (33% vs. 36%).

Chart 6: **Accuracy of Hydro Bills**

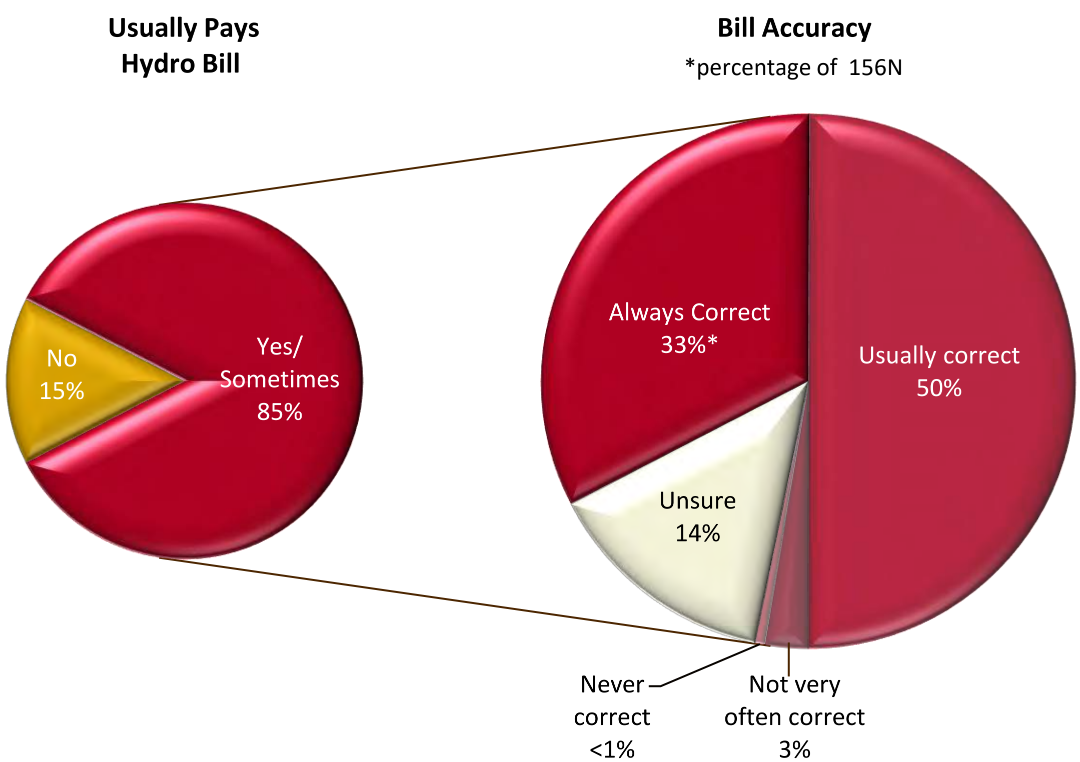
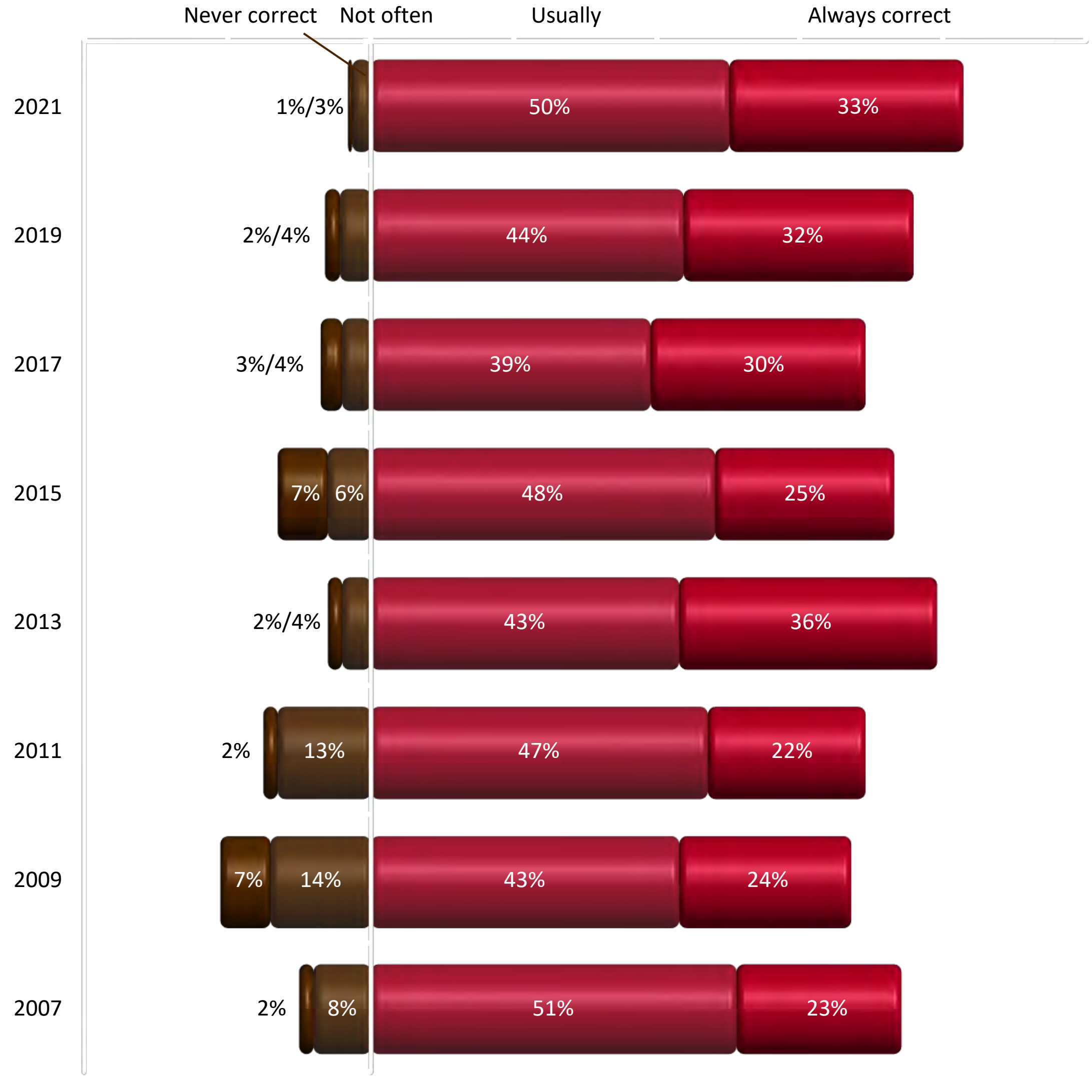


Chart 7: **Billing Accuracy**

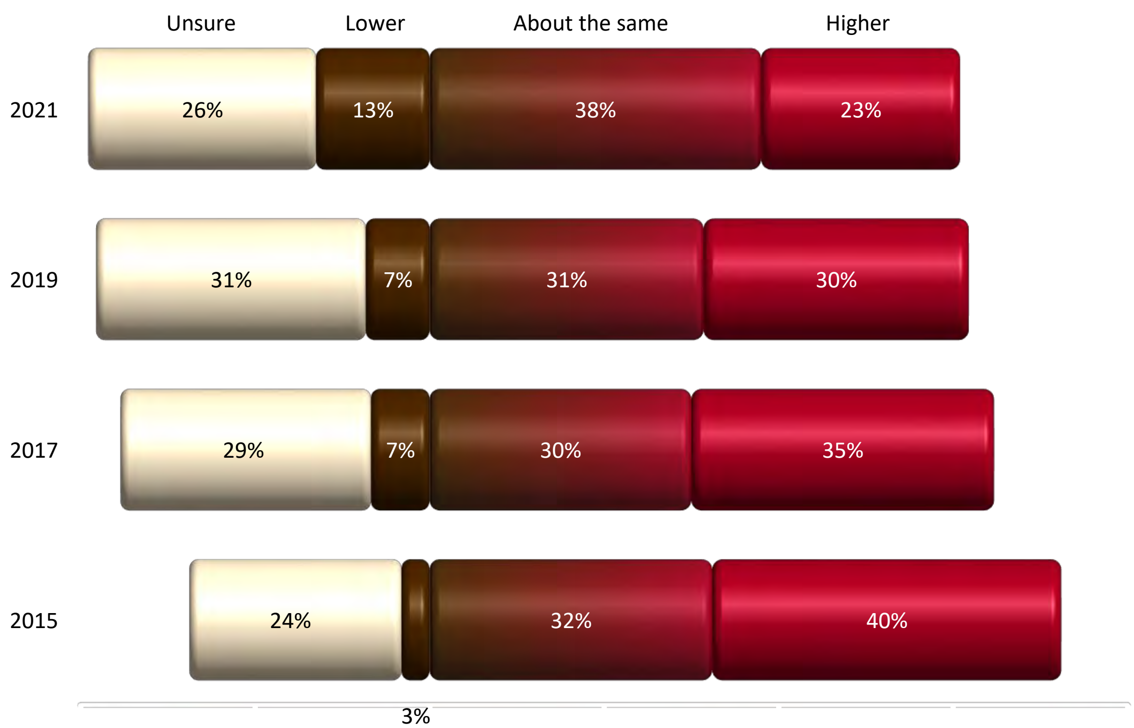


- Customers who are very satisfied with their Hydro One Remotes service are more likely to say their bill is always correct (58%) than those who are moderately satisfied (20%).

Rates vs. Rest of Ontario (Q16)

Six in ten Hydro One Remotes customers believe their Hydro rates are either the same as the rest of Ontario (38%) or higher (23%), while one in four are unsure (26%). About 13% of customers believe their rates are lower. The perception that their rates are higher has dropped steadily since this question was first asked in 2015.

Chart 8: **Rates vs. Rest of Ontario**



- Very satisfied respondents are more likely than satisfied respondents to think their bills are about the same (52% vs. 32% moderately satisfied) or lower than the rest of Ontario (21% vs. 9% moderately satisfied). Moderately satisfied respondents are more likely to think their bills are higher (29% vs. 8% very satisfied).

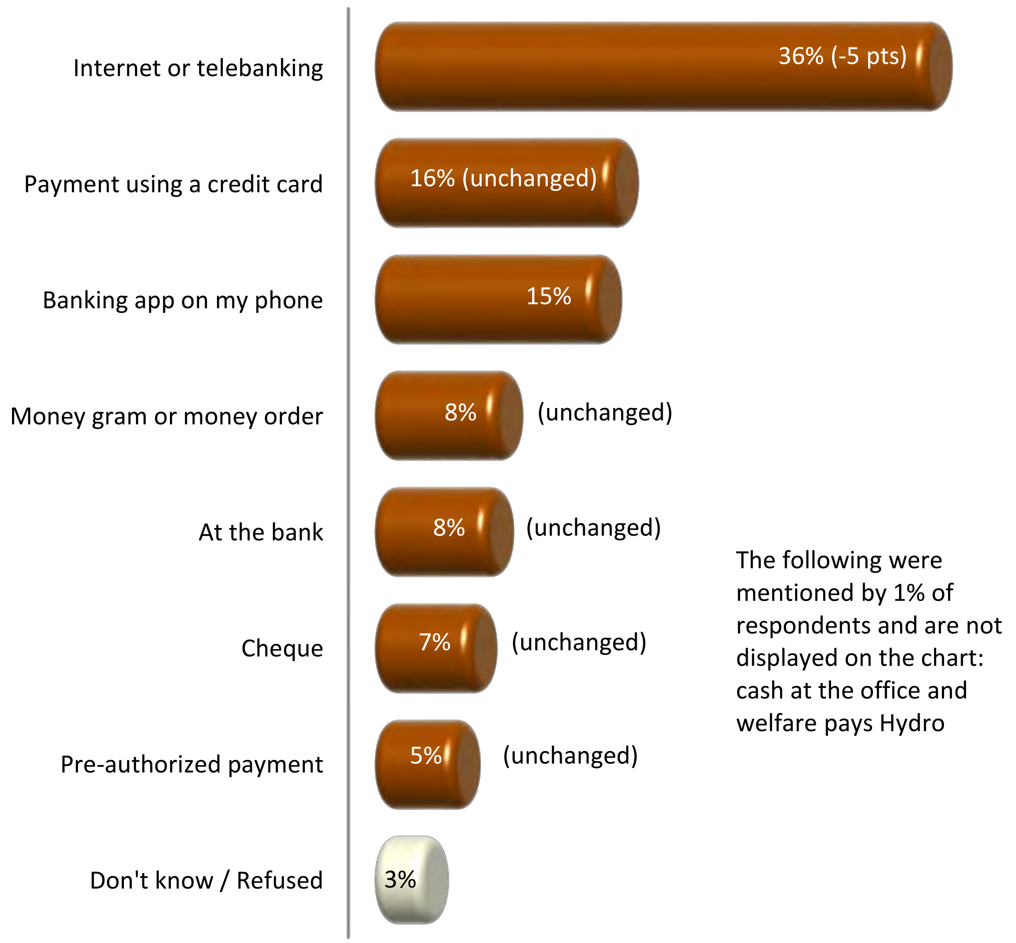
Preferred Bill Payment Method (Q12)

Customers were presented with a number of options for paying their Hydro bill and asked to select their one preferred method. More than a third of customers chose internet or telebanking (36%), 19% opted for credit card payments and 15% selected the banking app on their phone.

Fewer than one in ten respondents chose another payment option including a money order, at the bank (each 8%), by cheque (7%), pre-authorized payment (5%), at the office or by welfare (each 1%). Three percent (3%) of respondents were unsure how to respond.

Differences from 2019 are noted on Chart 9, but are largely unchanged. Caution should be used in compared current results to those in 2019 since the list of response options changed, adding *banking app on my phone*.

Chart 9: **Preferred Bill Payment Method**



- In communities with 9+ respondents, internet/telebanking is the preferred way of paying their Hydro bill in most communities. Pikangikum customers are more likely to prefer using their banking app (17% vs. 8% internet/telebanking) and Weagomow/North Caribou/Round Lake customers like internet/telebanking or using their banking app equally (each 33%).
- Paying their Hydro bill by cheque or internet/telephone banking increases with age, while using a banking app drops as age rises.
- 18 to 34 year olds are more likely to use money orders (15% vs. 8% respondents overall), 35 to 54 year olds are more likely to use pre-authorized payments (8% vs. 5% respondents overall) or credit/debit cards (21% vs. 16% respondents overall) and those 55+ are more likely to pay at the bank (14% vs. 8% respondents overall).
- Residential customers are more likely than business customers to pay their Hydro bill on their banking app, by telephone/internet banking, money order or cash, while business customers are more likely to pay by cheque, pre-authorized payment, credit/debit care or at the bank.

Customer Contact

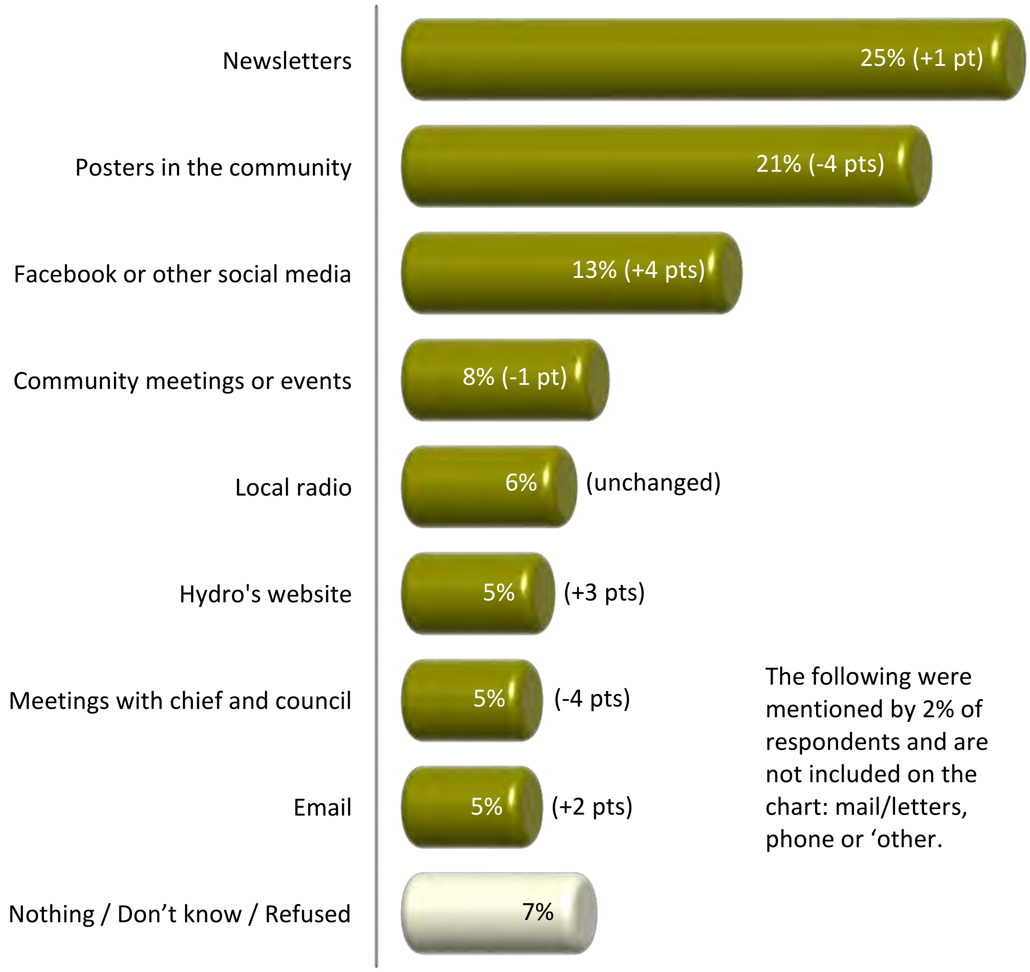
Preferred Method of Communication by Hydro One Remotes (Q19)

When asked the best method Hydro One Remotes should use to communicate with them about its service and programs, almost half of respondents chose either posters in the community (21%, -4 points since 2019) or newsletters (25%, +1 point). One in eight prefer communication through Facebook or other social media (13%, +4 points).

Other methods that appealed to fewer than one in ten customers are community meetings (8%, -1 point) and local radio (6%, unchanged).

Fewer customers selected Hydro's website, meetings with chief and council, email (each 5%), mail or phone (each 2%). Two percent (2%) mentioned another method and 7% were unsure.

Chart 10: **Preferred Method of Communication from Hydro One Remotes**

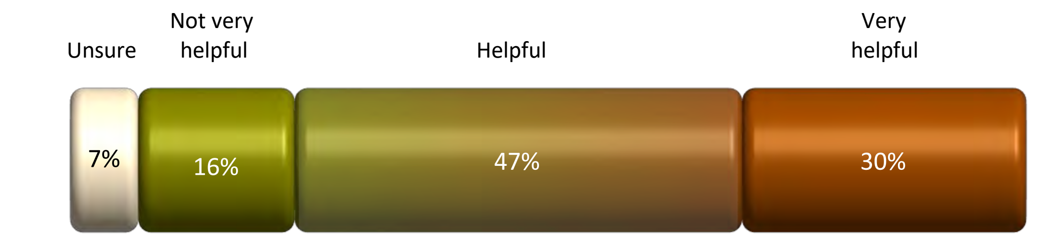


- Very satisfied Hydro One Remotes customers are more likely than moderately satisfied customers to favour newsletters, meetings with chief and council, posters, email, letters or phone communication from the utility. Moderately satisfied members are more likely to choose community meetings, local radio or Hydro’s website.

Customer Service in Respondents' Indigenous Language *(Q20)*

More than three in four respondents said it would be helpful (47%) or very helpful (30%) to have a customer service representative with whom they could discuss their Hydro bill in their Indigenous language. One in eight said this would not be very helpful (16%) and 7% were unsure.

Chart 11: **Customer Service in Respondents' Indigenous Language**



- Among communities with 9+ respondents, those most likely to say customer service in their Indigenous language would be helpful are residents of Big Trout Lake/KI, Deer Lake and Pikangikum (each 100%). Sultan residents are least likely to feel this would be helpful (22%).

Incidence of Contact *(Q6)*

Two thirds of customers said they did not contact Hydro One Remotes in the past year (64%), down 6 points since 2019 but higher than earlier waves of research.

As in previous years, the most common reason customers contacted the utility was to discuss their bill (16%, up 4 points since 2019). Other reasons for contact included because the power is out (10%, down 1 point), and needing information (8%, up 2 points). One in ten respondents contacted Hydro One Remotes for another reason (11%) and 1% did not recall.

Chart 12 summarizes 2021 responses and Table 3 compares current responses to previous waves of research.

Chart 12: **Incidence of Contact**

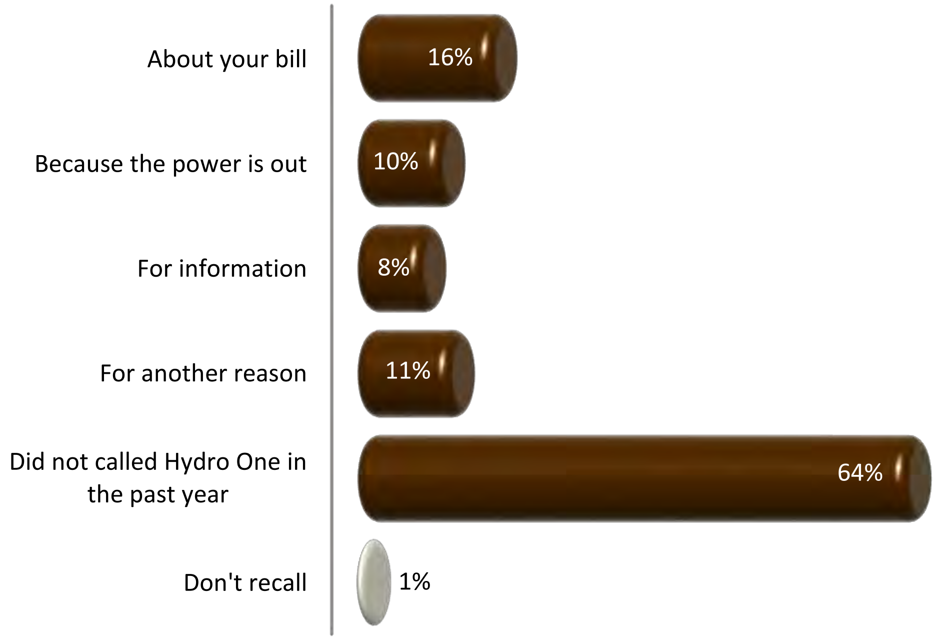


Table 3: **Incidence of Contact Over Time**

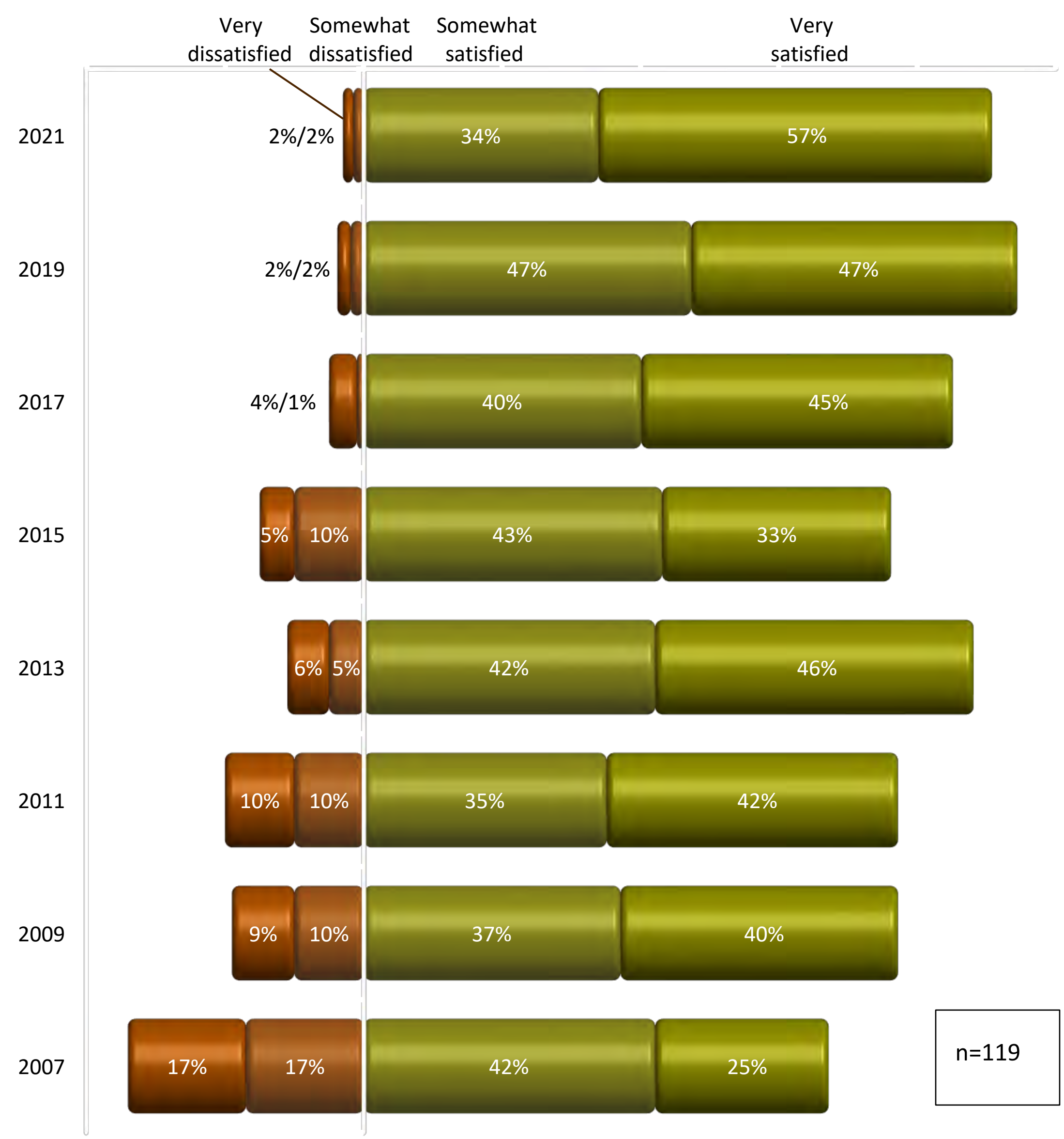
Nature of Inquiry	2021	2019	2017	2015	2013	2011	2009
About your bill	**16%**	12%	31%	26%	19%	24%	20%
For information	**8%**	6%	17%	17%	12%	13%	18%
Because power was out	**10%**	11%	15%	9%	11%	15%	15%
Another reason	**11%**	5%	12%	13%	9%	10%	9%
Did not call Hydro One Remotes in the past year	**64%**	70%	51%	58%	62%	54%	57%
Don't recall	**1%**	2%	1%	0%	1%	2%	2%

Percentages do not total 100% because customers were permitted more than one response

Satisfaction with Customer Contact (Q7)

Among customers who called Hydro One Remotes (n=119), respondents very satisfied with how the utility handled their contact reached its highest level yet recorded (57%, up 10 points over 2019 results). When very and somewhat satisfied responses were combined, this years' results fell to second place overall, 3 points behind 2019 responses at 91%. Just 4% of customers said they were dissatisfied and 6% were unsure.

Chart 13: **Satisfaction with Customer Contact**



Perceptions of Hydro One Remotes (Qs 8 - 10)

This research tested customers' agreement with three statements related to customer service, to explore customers' experiences and perceptions in key service areas. Hydro One Remotes scored best at *dealing with emergencies* (91% agree overall) and *staff being polite and friendly* (73%). Customers were less likely to agree that *when they call the Hydro One office someone usually answers quickly,* though more than half agreed (57%). Hydro One Remotes scored better than in 2019 on all statements and *dealing with emergencies* scored the highest of seven waves of research. The other two statements, although better than 2019, did not reach levels achieved prior to that. Responses to these questions suggest about one in four respondents did not call the Hydro One office.

Chart 14 summarizes 2021 responses and Table 4 compares current responses with past waves of research.

Chart 14: **Perceptions of Hydro One Remotes**

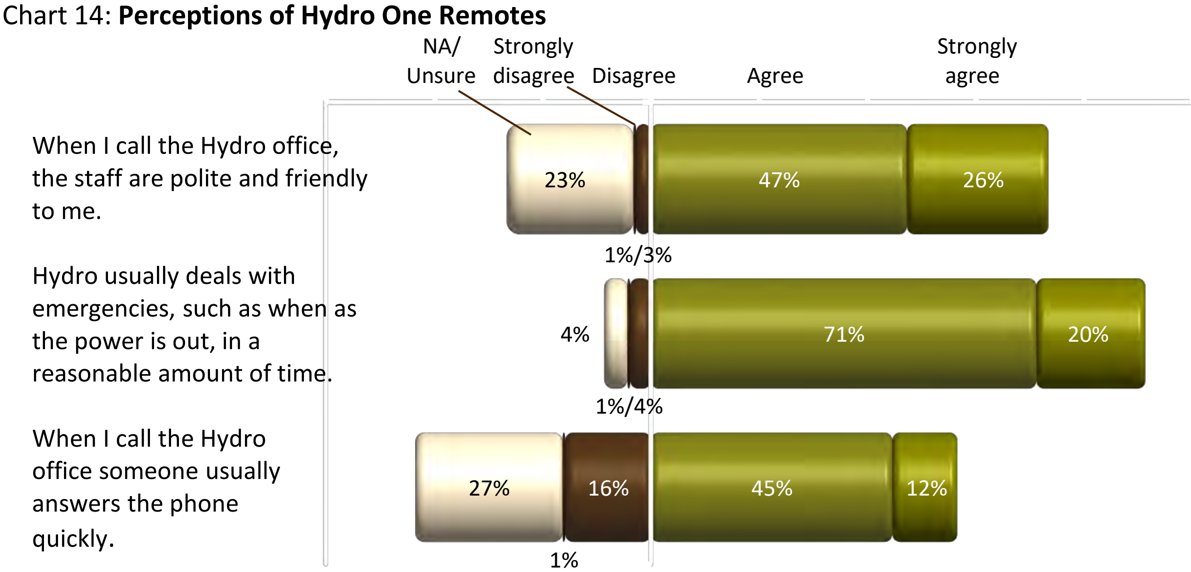


Table 4: **Perceptions of Hydro One Remotes**

Statement	2021	2019	2017	2015	2013	2011	2009
Hydro One usually deals with emergencies, such as when the power is out, in a reasonable amount of time.	**91% (20%)***	74% (15%)	82% (15%)	80% (15%)	88% (18%)	85% (20%)	86% (18%)
When I call the Hydro One office, the staff are polite and friendly to me.	**73% (26%)**	60% (16%)	79% (18%)	75% (17%)	80% (20%)	80% (18%)	80% (20%)
When I call the Hydro One office someone usually answers the phone quickly.	**57% (12%)**	48% (13%)	60% (13%)	62% (11%)	65% (11%)	61% (12%)	68% (12%)

*Unbracketed percentages combine agree and strongly agree responses, bracketed percentages isolate strongly agree responses.

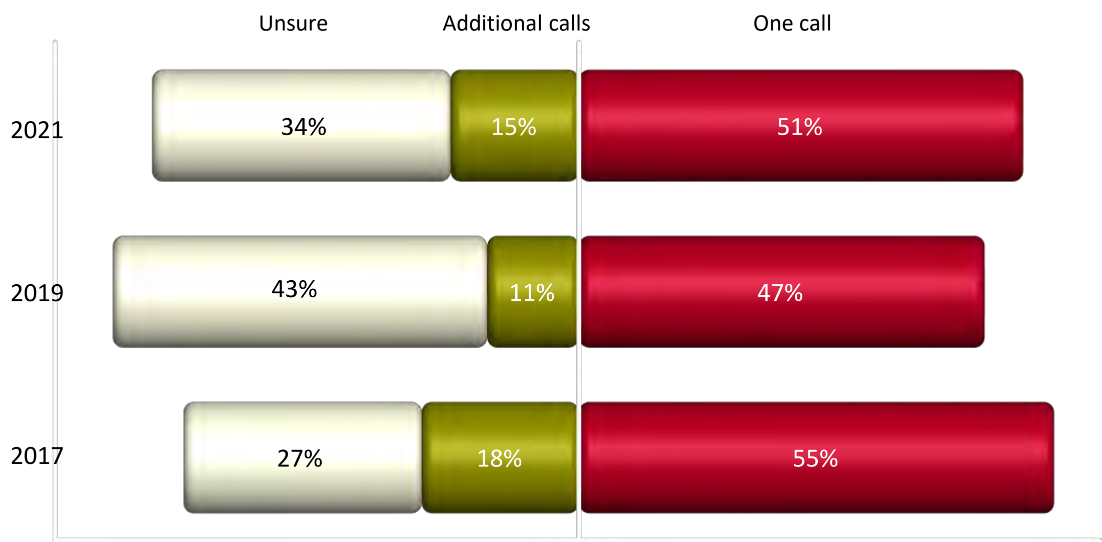
- For each of these statements, customers who are very satisfied with their Hydro One Remotes service are more likely to agree than moderately satisfied respondents.
- Customers who heat with electricity are twice as likely to strongly agree **Hydro usually deals with emergencies in a reasonable amount of time** (39%) than those who heat with another energy source (18%).
- Customers who heat with electricity are less likely to agree **Hydro answers the phone quickly when they call** (39%) than those who heat with another energy source (61%).

Number of Calls Needed for Resolution (Q11)

More than half of customers said their question or concern was resolved the first time they called Hydro One Remotes (51%, up 4 points since 2019), while 15% said an additional call was required (up 4 points) and 34% were unsure (down 9 points). These unsure responses suggest some respondents did not call the Hydro One office.

These results show improvement since 2019, but are not as favourable as in 2017.

Chart 15: **Number of Calls Needed for Resolution**



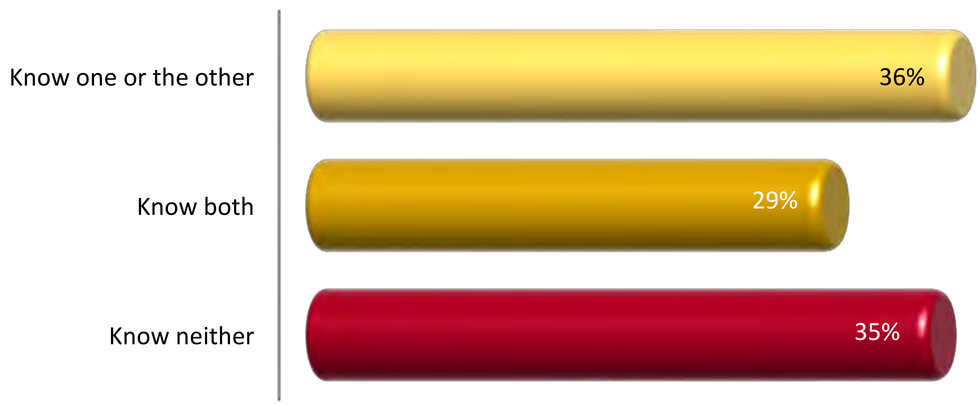
- Customers who contacted Hydro in the last year were more likely to say their question or concern was resolved the first time they called (71%) than those who had not contacted Hydro in the last year (40%).
- Those who had not contacted Hydro in the last year were more likely to be unsure of the outcome of their call (49%), compared to those who had contacted Hydro within the last year (8%).

Awareness of Local Operators & Meter Readers (Q13)

More than one third of customers know who both their operator and their meter reader is (29%, down 5 points since 2019), while slightly more know one but not the other (36%). A similar number know neither their meter reader nor their operator (35%).

A wording change does not allow further comparison to past results for this question.

Chart 16: **Awareness of Local Operators & Meter Readers**



Contact During Outages (Q15)

A majority of customers do not call anyone when there is an outage (60%, up 5 points since 2019). About two in ten call either the band office (9%, down 3 points) or the phone number on their bill (9%, down 1 point). Fewer customers call the meter reader (7%, up 3 points), the emergency hotline (5%, down 4 points) or the operator (5%, down 1 points). Five percent (5%) are unsure.

In communities of 9+ respondents, residents are most likely to call:

- **Armstrong/Whitesands/Collins** the emergency hotline (24% vs. 5% respondents overall)
- **Bearskin Lake** the band office or the phone number on the bill (each 9% vs. 9% respondents overall),
- **Big Trout Lake/KI** their operator (9% vs. 5% respondents overall),
- **Biscotasing** their meter reader (33% vs. 7% respondents overall),
- **Deer Lake** the band office or the phone number on the bill (each 8% vs. 9% respondents overall),

- **Pikangikum** the band office (17% vs. 9% respondents overall),
- **Sultan** their meter reader (44% vs. 7% respondents overall),
- **Sandy Lake** the band office (28% vs. 9% respondents overall), and
- **Weagamow/North Caribou/Round Lake** the band office (13% vs. 7% respondents overall).
- **Big Trout Lake/KI** residents are most likely not to call anyone when there is an outage (91%) and **Biscotasing** residents are least likely not to call (22%).

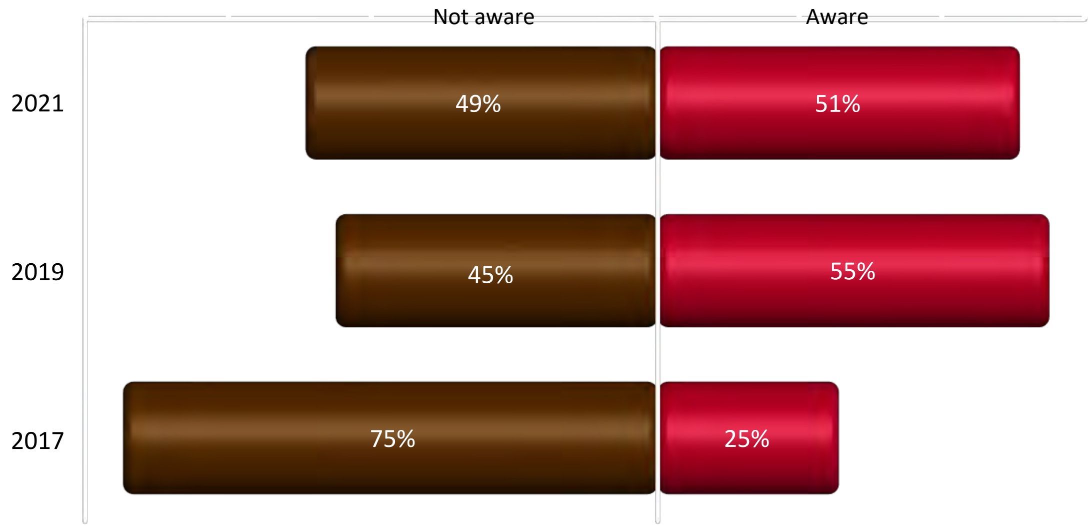
Chart 17: **Contact During Outages**

Electricity Support Programs

OESP (Q17)

Awareness of the Ontario Electricity Support Program (OESP) remains high (51%), though not quite as high as in 2019 (55%). Fewer than half of respondents were not aware of this program (49%, up 4 points since 2019).

Chart 18: **OESP Program**

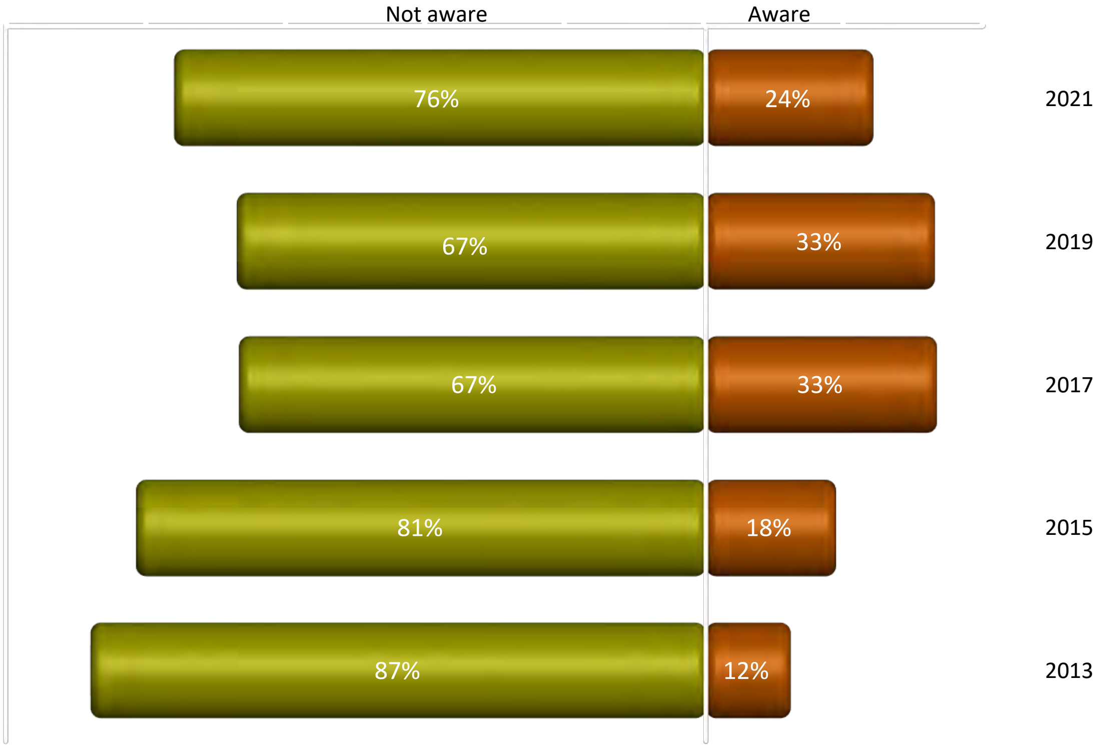


- Among communities with 9+ respondents, the following residents are more likely to have heard about OESP: Sultan (78%), Weagamow/North Caribou/Round Lake (73%), Armstrong/Whitesands/Collins (59%), Bearskin Lake (55%) and Deer Lake (54%), compared to respondents overall (51%). Those least likely to have heard of OESP live in Big Trout Lake/KI (36%) and Biscotasing (33%).

LEAP (Q18)

Awareness of the Low-Income Emergency Assistance Program (LEAP) is also lower among these respondents, with 24% of respondents aware of the program, down 9 points, and 76% unaware of it, up 9 points.

Chart 18: **LEAP Program**



- Among communities with 9+ respondents, the following residents are more likely to have heard about LEAP: Biscotasing (44%), Pikangikum (42%), Deer Lake (38%) and Sultan (33%), compared to respondents overall (24%). Those least likely to have heard of LEAP live in Sandy Lake (12%).
- Respondents who are satisfied with the service from Hydro One Remotes are more than twice as likely to have heard of LEAP (38%) than moderately satisfied respondents (17%).

Appendix C

Report on the Chiefs & Council Survey 2021 Results

Report on the
Chiefs & Council Survey
2021 RESULTS

Prepared for Hydro One
Remote Communities

January 2022

Viewpoints Research
Winnipeg, Manitoba
(204) 988-9253
www.viewpoints.ca

TABLE OF CONTENTS

EXECUTIVE SUMMARY

On behalf of Hydro One Remote Communities (Hydro One Remotes), Viewpoints Research conducted a telephone survey of thirteen Chiefs and Council members representing communities served by Hydro One Remotes. Interviews were conducted between November 23rd and December 9th. Leaders' verbatim responses to open-ended questions can be found in Appendix A.

Most Important Community Electricity Issue

Asked what they believe is the most important electricity issue in their community, t*he cost of electricity to the Band* and the *reliability of the service* were each the choice of three leaders (each 23%), followed by *electrical safety* (15%).

Other options, each selected by one respondent, were: *saving their community members money on their bills, having a good relationship with Hydro One Remotes with open communications, getting connected to the provincial electrical grid* and *the wait for connection to residential and commercial service* (each 8%).

Awareness of Hydro One Remotes Community Programs

Most leaders are aware of Hydro One Remotes' *streetlight and streetlight retrofit programs* and an *Energy Star rebate program* (each 69%), while eight leaders are aware of the *community sponsorship program* (62%). A majority are aware of *Reindeer* and a *commercial lighting retrofit program for Band-owned buildings* (each 54%). Just one leader was aware of the *Customer Advisory Board* (8%).

Promoting Hydro One Remotes Community Programs

When asked how best to promote Hydro One Remotes' community programs, leaders engaged most with the idea of *Hydro One Remotes staff coming to their community to give a presentation*. It was the first choice of six respondents (46%) and the second choice of five others (39%). *Mailouts and letters included in Hydro bills* was the first choice of three leaders and the second choice of three (each 23%).

Awareness of Hydro One Remotes Financial Support Programs

More than half of leaders were aware of the *Low-Income Electricity Assistance (LEAP) program* (53%, 7 respondents), while five were aware of the *Ontario Electricity Support Program (OESP)* (39%).

Promoting Hydro One Remotes Financial Support Programs

As with the community programs, leaders engaged most with the idea of *Hydro One Remotes staff coming to their community to give a presentation* about its financial support programs - the choice of five respondents (39%). *Mailouts and letters included in Hydro bills* was the choice of four leaders (31%) and two selected *letters sent directly to customers (15%).*

Awareness of Hydro One Remotes Community Investment Programs

A majority of leaders are aware of Hydro One Remotes' interest in developing *business partnerships with communities for fuel storage and renewable energy* (54%). Fewer are aware of *training Hydro Operators receive through Hydro One Remotes* (46%). Just two leaders are aware of *Hydro One's status in the PAR Program* and *as an environmental leader meeting ISO 1401 standards* (each 15%). None of the leaders interviewed is aware of the scope of *Hydro One's relationships with Indigenous-owned businesses* (100% unaware).

Merit of Hydro One Remotes Customer Outreach

Leaders thought four of the six Hydro One Remotes initiatives related to customer outreach the survey tested are either somewhat or very worthwhile. *Making newsletters available in English and in Indigenous language* was deemed very worthwhile by all but one leader (92%), who felt it was somewhat worthwhile (8%).

Twelve leaders felt *making program material available in Indigenous languages* is either very worthwhile (85%) or somewhat worthwhile (8%) and another respondent was unsure (8%).

Delivering the 2021 Artist Calendar is considered very worthwhile by eigth leaders (62%) and somewhat worthwhile by 39%.

The *Electrical Safety Colouring Book* was identified as very worthwhile by nine respondents (69%), somewhat worthwhile by three (23%) and not very worthwhile by one (8%).

Newsletters featuring stories on projects and people in the North is considered very worthwhile by eight leaders (62%) and somewhat worthwhile by five (39%).

While mass e-mails have the least merit of the outreach mentioned, five leaders suggest they are very worthwhile (39%) and eight said they are somewhat worthwhile (62%).

Hydro One Remotes Website

Leaders were asked, in their own words, what they would like to see on the new website Hydro One Remotes is currently creating, and several themes emerged in their responses. Six respondents would like to see *information about available initiatives and programs, and how to save on electricity costs* (46%). Three people mentioned *information and updates about the initiatives and energy usage in their communities.* Two people suggested each of the following: *an interactive social media platform that allowed comments and information from the community* and *how to easily contact Hydro One and ask questions in their Indigenous language* (each 23%). One person would like to see *job postings* on the website (8%) and three people did not provide a response (23%).

Hydro One Remotes' Handling of COVID-19

Leaders were asked to rate Hydro One Remotes on its handling of their community's COVID-19 concerns. All but one respondent provided a response, and those who did were all positive. Ten people felt Hydro One Remotes did very well (77%) and two said the utility did somewhat well in this regard (15%).

Among those who said Hydro did very well, 75% felt the utility's *communication was good* and 67% felt they *followed COVID-19 guidelines and protocols*. Those who said Hydro did somewhat well noted *the utility did not respond to some outages* and *did not follow COVID-19 safety protocols*.

Hydro One Remotes' Responsibilities

The survey tested thirteen Hydro One Remotes responsibilities, asking leaders to rate the utility as doing a very good, good, fair or poor job in each area. Hydro One Remotes earned the highest ratings for *responding to emergencies* (92% very good/good combined) and *providing reliable electric power* (93%).

Keeping Council fully informed about bill collections and disconnections earned 93% good/very good ratings and 8% poor ratings.

A majority of leaders gave the utility good/very good ratings for: *providing their community with information regarding planned power outages* (85%), *keeping in touch with customers* (78%), *protecting land, water and air, keeping in touch with Council on important matters, communicating with community leaders when power is likely to come back on after an outage, educating communities about safety around powerlines* (each 69%), *responding to concerns raised by chief and council* (63%) and *working with Councils on project planning in communities* (54%).

Fewer leaders gave Hydro One Remotes good or very good ratings for *cost estimates* (38%) and *timely service connection* (39%).

Quality of Service

A majority of leaders feel the overall service provided by Hydro One Remotes has improved over the past five years (54%, 7 respondents), while six respondents said it has stayed the same (46%) and no one said it has worsened.

Reasons for Improvement

Among leaders who said service has improved, three mentioned each of the following: *an upgraded power generator* and *same day response to outages/fast work* (each 43%). One respondent cited *training provided to the local band* (14%).

Hydro One Remotes' Strengths

Asked the one thing Hydro One Remotes does best, almost half of leaders spoke of the utility's capacity to *provide electricity to their community and maintain its generators* (46%, 6 respondents). Four respondents noted the *reliability of the service* (31%) and one each cited *communication with Council* and *providing their community the time needed to address issues* (each 8%).

Areas of Hydro One Remotes' Service Needing Improvement

Leaders offered their thoughts on the single most important thing Hydro One Remotes needs to improve on. Four respondents spoke to the *interactions of Hydro One staff with the local community in terms of courtesy, recognition and communication* (31%). Three others mentioned the *speed with which houses are provided electrical service* (23%) and two identified the *cost of installation and provision of Hydro service* (23%).

Watay Powerline

A series of questions were asked of nine respondents whose communities are expected to be connected to Ontario's provincial electricity grid within the next few years via the Watay Powerline.

Eight of nine leaders feel their community is ready to be connected to the power grid (89%), but only two of these said they are very ready (22%), while the rest feel only somewhat ready (67%). One leader concedes their community is not very ready for this change (11%).

Two thirds of leaders feel backup power is essential once their community is on the grid, and anticipate maintaining the existing generators to meet this need (67%). Another specified a diesel generator with a 2,000+ megawatt capacity (11%) would provide suitable backup power.

Leaders are unclear whether being on the provincial grid with increase their Hydro costs (33%), whether they will stay about the same (33%) or be lower (22%).

Asked how reliable they anticipate grid-connected electrical service will be, expectations are mixed. Four respondents expect it will be less reliable (44%), three think it will be the same (33%) and one anticipates it being more reliable (11%).

Five leaders feel the current Watay schedule for their community meets their expectations (56%), while two said it does not (22%).

Once on-grid, leaders are most likely to anticipate improved electrical capacity to connect more houses (44%, four respondents), while two expect higher Hydro costs (22%). One each mentioned less maintenance or reduced environmental impact.

GOALS & METHODOLOGY

Goals

On behalf of Hydro One Remote Communities (Hydro One Remotes), Viewpoints Research conducted a telephone survey of thirteen Chiefs and Council members representing communities served by Hydro One Remotes. Interviews were conducted between November 23rd and December 9th, 2021. A second survey with Hydro One Remotes customers was also conducted in December 2021/January 2022, and is reported on in a separate document. The survey explored:

- Perceptions of the most important electrical safety issue in their community,
- Awareness of Hydro One Remotes programs available to communities,
- How best for Hydro One Remotes to promote its programs in their community,
- Awareness of community investment initiatives Hydro One Remotes has or is interested in developing,
- The value of customer outreach initiatives recently undertaken by Hydro One Remotes,
- Ideas the Remote Communities website currently under development,
- Perceptions of Hydro One Remotes' handling of their communities' COVID-19 concerns, and why,
- Perceptions of the job Hydro One Remotes is doing with various aspects of its work as their community's electricity provider,
- Perceptions of the quality of service provided by Hydro One Remotes, and reasons for their assessment, and
- Perceptions of Hydro One Remotes' strengths and areas for improvement.

The survey also explored respondents' perceptions of changes coming to their communities when they are connected to the Watay Powerline.

Methodology

Hydro One Remote Communities serves 15,000+ people in 22 off-grid communities in Northern Ontario. Viewpoints Research undertook to contact the leadership in these communities to explore their awareness and perceptions of, and satisfaction with, Hydro One Remotes.

Hydro One Remotes provided Viewpoints with the contact names and phone numbers of chiefs and council members in the communities it serves in order to contact them to participate in the survey. Thirteen leaders were interviewed.

Reporting

This report highlights the overall views and perceptions of the Hydro One Remotes Communities' leaders interviewed.

RESEARCH FINDINGS

Most Important Community Electricity Issue

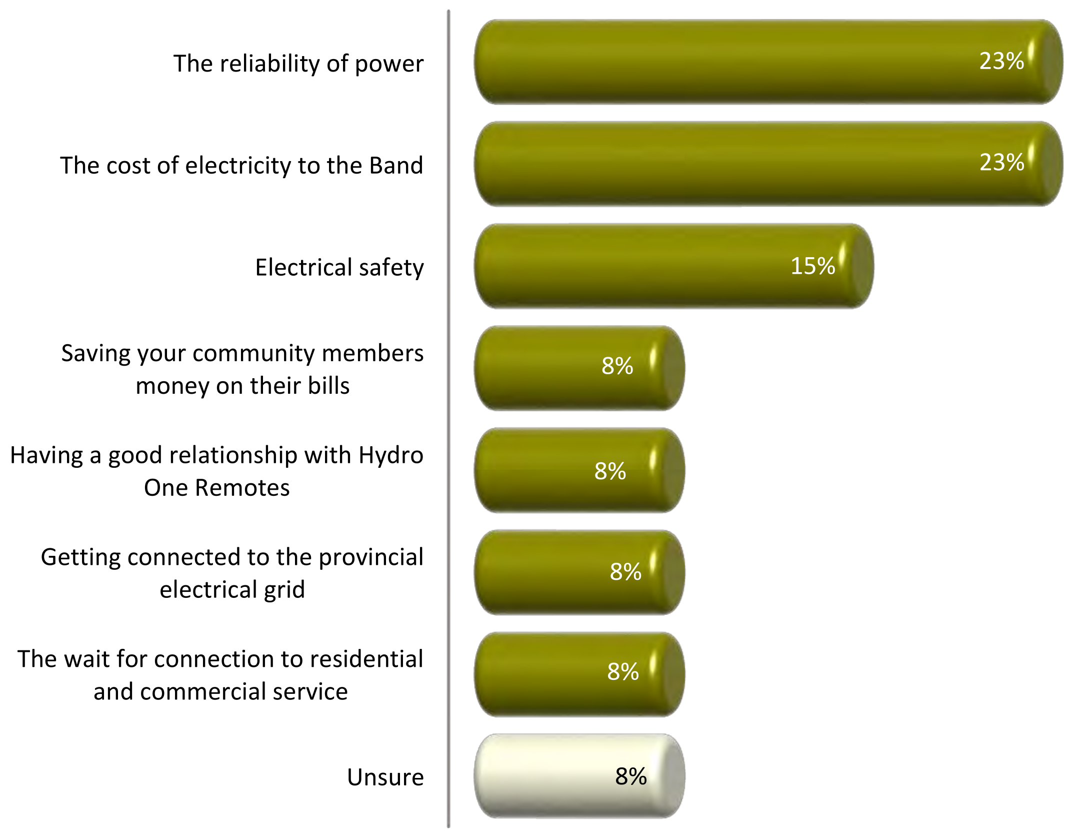
Leaders were asked what they believe is the most important electricity issue in their community, from a list of responses provided by the interviewer.

The cost of electricity to the Band and the *reliability of the service* were each the choice of three respondents (each 23%), followed by *electrical safety* (15%, two respondents).

Other options, each selected by one respondent, were: *saving their community members money on their bills, having a good relationship with Hydro One Remotes with open communications, getting connected to the provincial electrical grid* and *the wait for connection to residential and commercial service* (each 8%).

No one chose *capacity and connection restrictions, an affordable cost to bands for new connections* or *protecting land, water and air.* One leader was unsure how to answer the question.

Chart 1: **Most Important Community Electricity Issue**



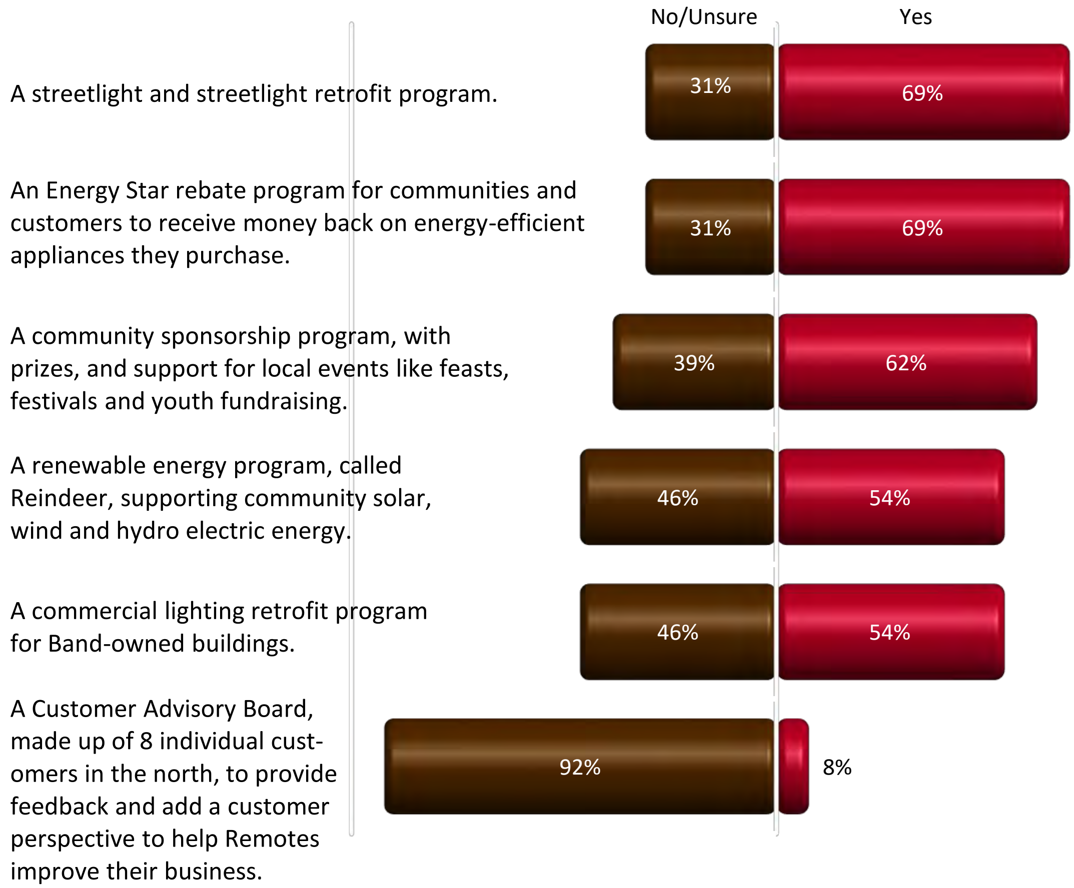
Awareness of Hydro One Remotes Community Programs

Most leaders are aware of Hydro One Remotes' *streetlight and streetlight retrofit programs* and an *Energy Star rebate program* (each 69%, 9 respondents), while eight leaders are aware of the *community sponsorship program* (62%).

A majority are aware of *Reindeer* and a *commercial lighting retrofit program for Band-owned buildings* (each 54%, 7 respondents).

Just one leader was aware of the *Customer Advisory Board* (8%).

Chart 2: **Awareness of Hydro One Remotes Community Programs**

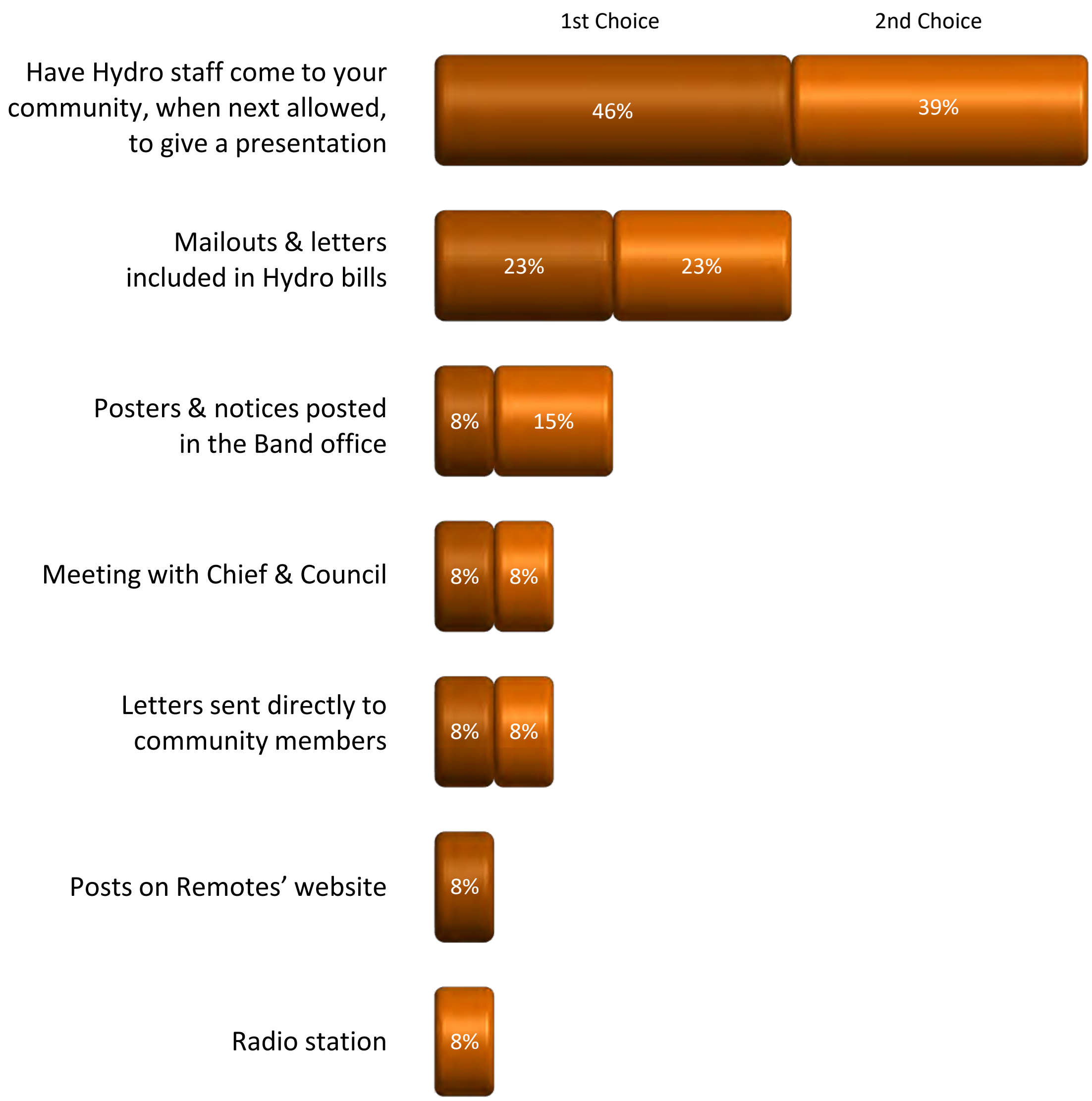


Promoting Hydro One Remotes Community Programs

Leaders engaged most with the idea of *Hydro One Remotes staff coming to their community to give a presentation* when asked how best to promote its community programs. It was the first choice of six respondents (46%) and the second choice of five others (39%). *Mailouts and letters included in Hydro bills* was the first choice of three leaders and the second choice of three (each 23%).

Other options were the combined choices of three or fewer leaders, and are displayed on Chart 3, below.

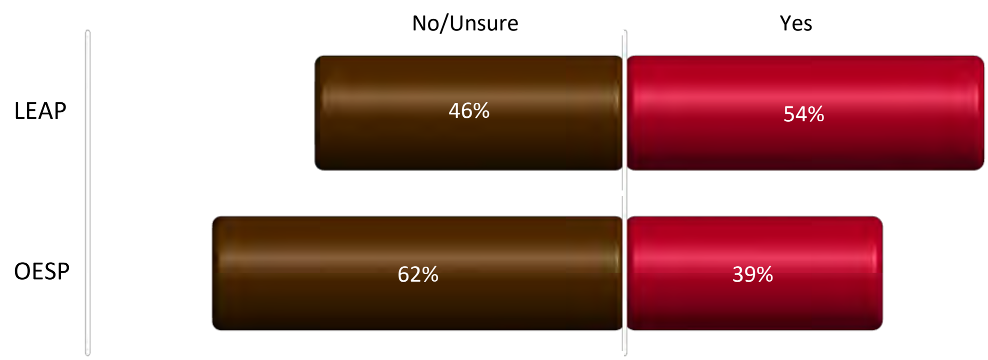
Chart 3: **Promoting Hydro One Remotes Community Programs**



Awareness of Hydro One Remotes Financial Support Programs

Leaders were asked their awareness of two Hydro One Remotes programs that help individual customers with their bills. More than half of respondents were aware of the *Low Income Electricity Assistance (LEAP) program* (53%, 7 respondents), while five leaders were aware of the *Ontario Electricity Support Program (OESP)* (39%).

Chart 4: **Awareness of Hydro One Remotes Financial Support Programs**

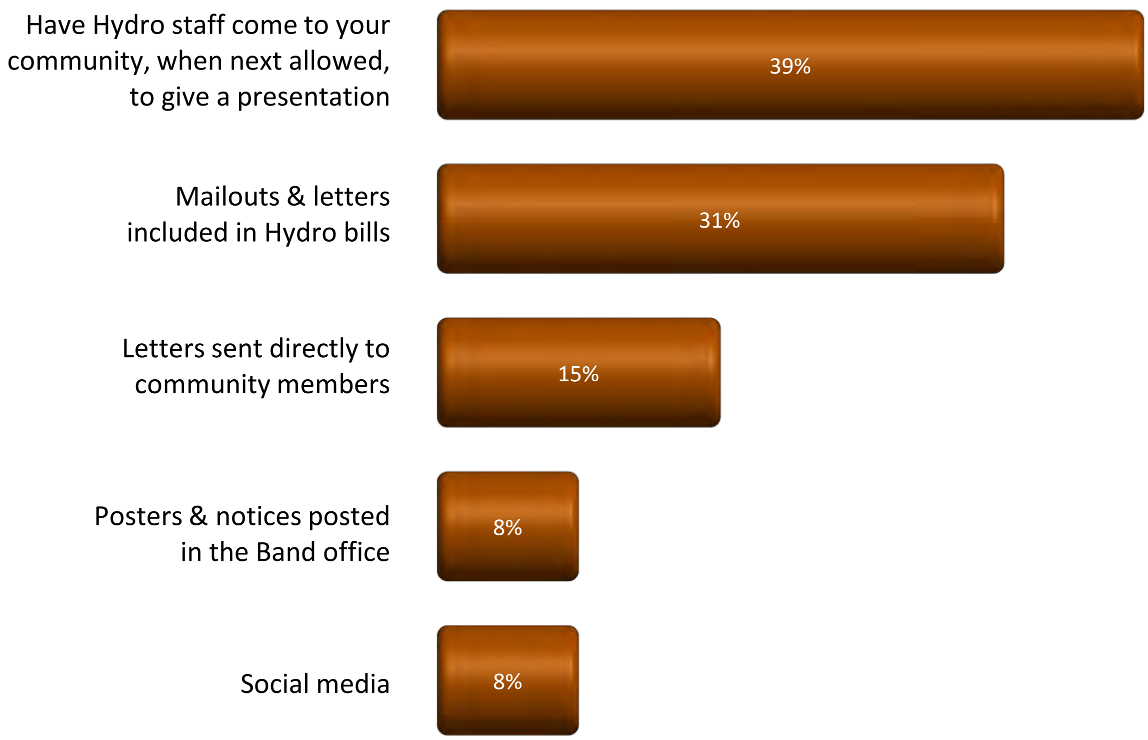


Promoting Hydro One Remotes Financial Support Programs

As with the community programs, leaders engaged most with the idea of *Hydro One Remotes staff coming to their community to give a presentation* about its financial support programs - the choice of five respondents (39%). *Mailouts and letters included in Hydro bills* was the choice of four leaders (31%) and two selected *letters sent directly to customers* (15%).

Other options were the choice of one leader each, and are displayed on Chart 5.

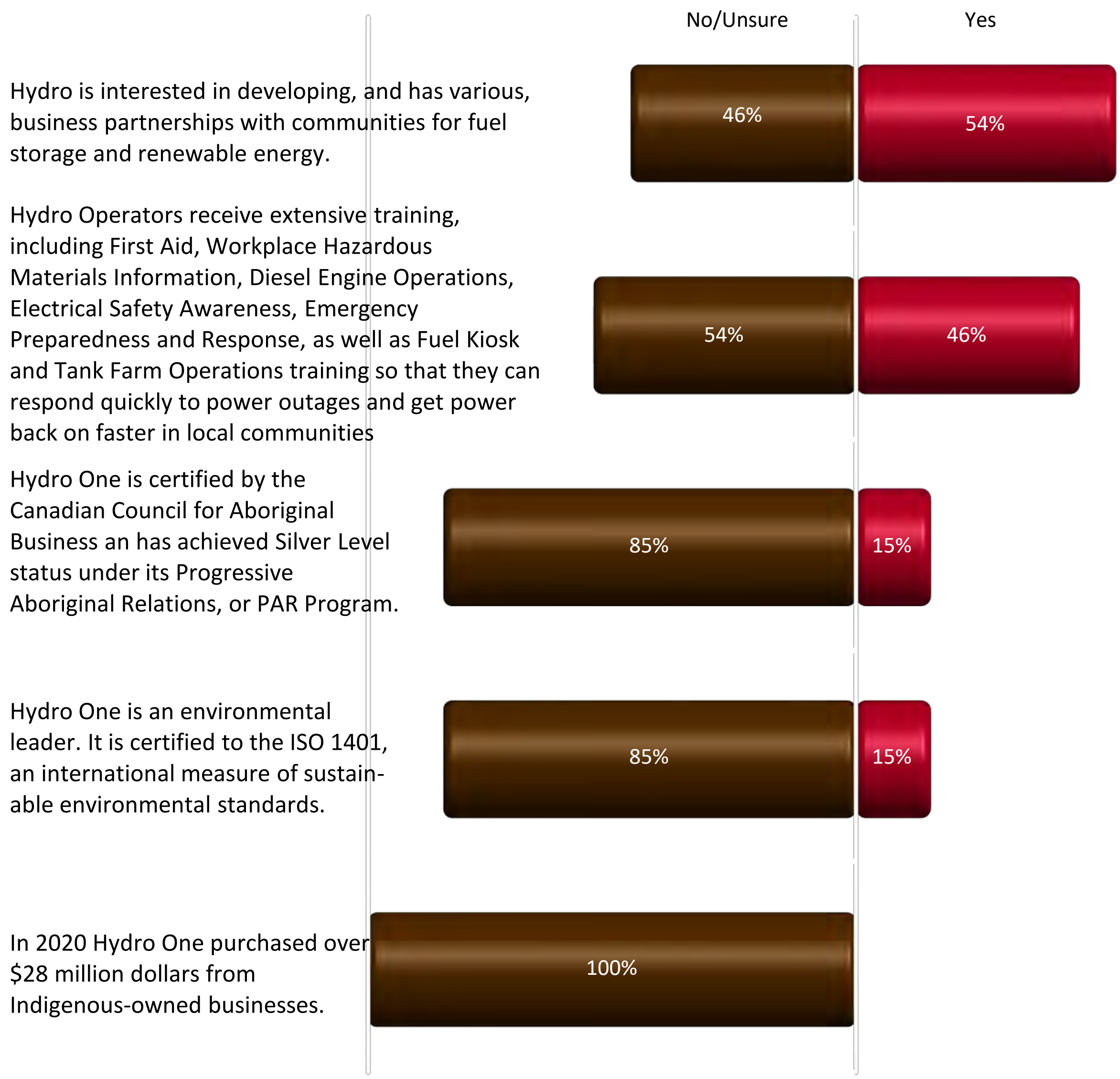
Chart 5: **Promoting Hydro One Remotes Financial Support Programs**



Awareness of Hydro One Remotes Community Investment Programs

A majority of leaders are aware of Hydro One Remotes' interest in developing *business partnerships with communities for fuel storage and renewable energy* (54%, 7 respondents). Fewer are aware of *training Hydro Operators receive through Hydro One Remotes* (46%, 6 participants). Just two leaders are aware of *Hydro One's status in the PAR Program* and *as an environmental leader meeting ISO 1401 standards* (each 15%). None of the leaders interviewed is aware of the scope of *Hydro One's relationships with Indigenous-owned businesses* (100% unaware).

Chart 6: **Awareness of Hydro One Remotes Community Investment Programs**



Merit of Hydro One Remotes Customer Outreach

Leaders thought four of the six Hydro One Remotes initiatives related to customer outreach the survey tested are either somewhat or very worthwhile. *Making newsletters available in English and in Indigenous language* was deemed very worthwhile by all but one leader (92%), who felt it was somewhat worthwhile (8%).

Twelve leaders felt *making program material available in Indigenous languages* is either very worthwhile (85%, 11 respondents) or somewhat worthwhile (8%, 1 respondent) and another respondent was unsure (8%).

Delivering the 2021 Artist Calendar is considered very worthwhile by eight leaders (62%) and somewhat worthwhile by 39% (5 leaders).

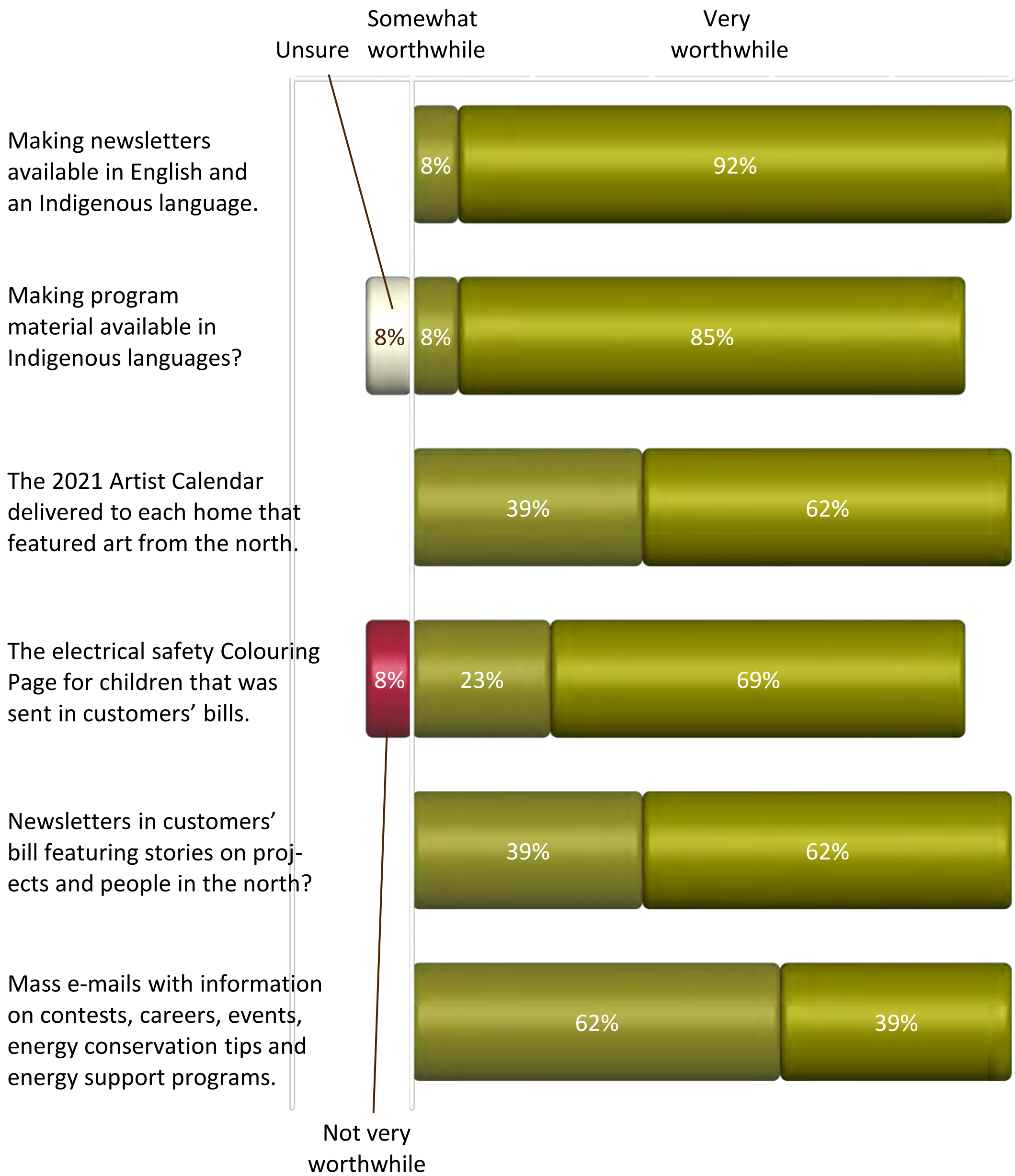
The *Electrical Safety Colouring Book* was identified as very worthwhile by nine respondents (69%), somewhat worthwhile by three (23%) and not very worthwhile by one (8%).

Newsletters featuring stories on projects and people in the North is considered very worthwhile by eight leaders (62%) and somewhat worthwhile by five (39%).

Mass e-mails had five leaders suggesting they are very worthwhile (39%) and eight who said they are somewhat worthwhile (62%).

Chart 7 on the following page displays respondents' responses to these questions.

Chart 7: **Merit of Hydro One Remotes Customer Outreach**

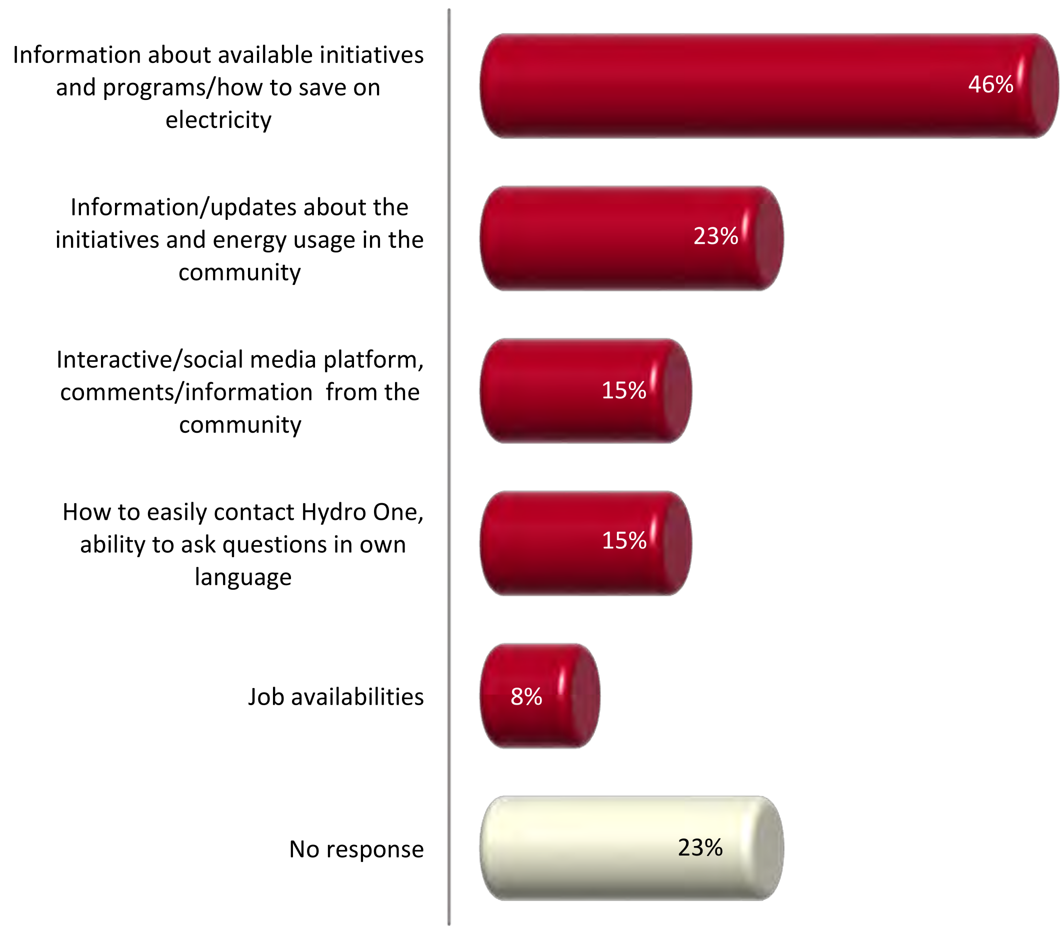


Hydro One Remotes Website

Leaders were asked, in their own words, what they would like to see on the new website Hydro One Remotes is currently creating, and several themes emerged in their responses. Six respondents would like to see *information about available initiatives and programs, and how to save on electricity costs* (46%). Three people mentioned *information and updates about the initiatives and energy usage in their communities.* Two people suggested each of the following: *an interactive social media platform that allowed comments and information from the community* and *how to easily contact Hydro One and ask questions in their Indigenous language* (each 23%). One person would like to see *job postings* on the website (8%) and three people did not provide a response (23%).

Respondents' verbatim responses to this question can be found in Appendix A.

Chart 8: **Hydro One Remotes Website**



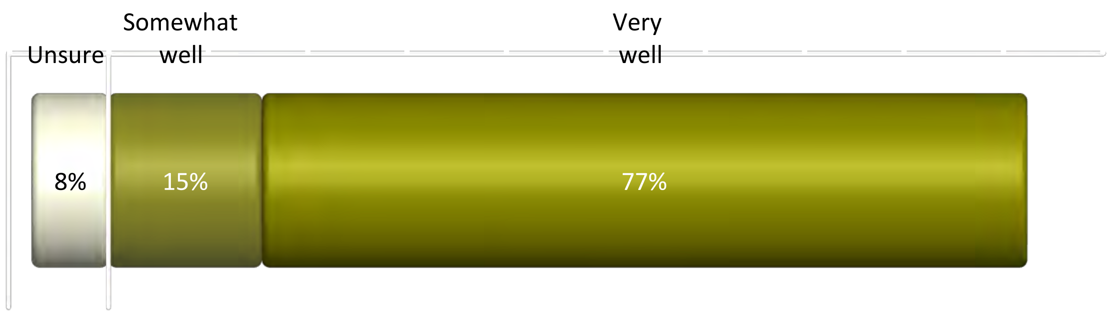
Hydro One Remotes' Handling of COVID-19

Leaders were asked to rate Hydro One Remotes on its handling of their community's COVID-19 concerns. All but one respondent provided a response, and those who did were all positive. Ten people felt Hydro One Remotes did very well (77%) and two said the utility did somewhat well in this regard (15%).

Among those who said Hydro did very well, 75% felt the utility's *communication was good* and 67% felt they *followed COVID-19 guidelines and protocols*. Those who said Hydro did somewhat well noted *the utility did not respond to some outages* and *did not follow COVID-19 safety protocols*.

Respondents' verbatim responses to this question can be found in Appendix A.

Chart 9: **Hydro One Remotes' Handling of COVID-19**



Hydro One Remotes' Responsibilities

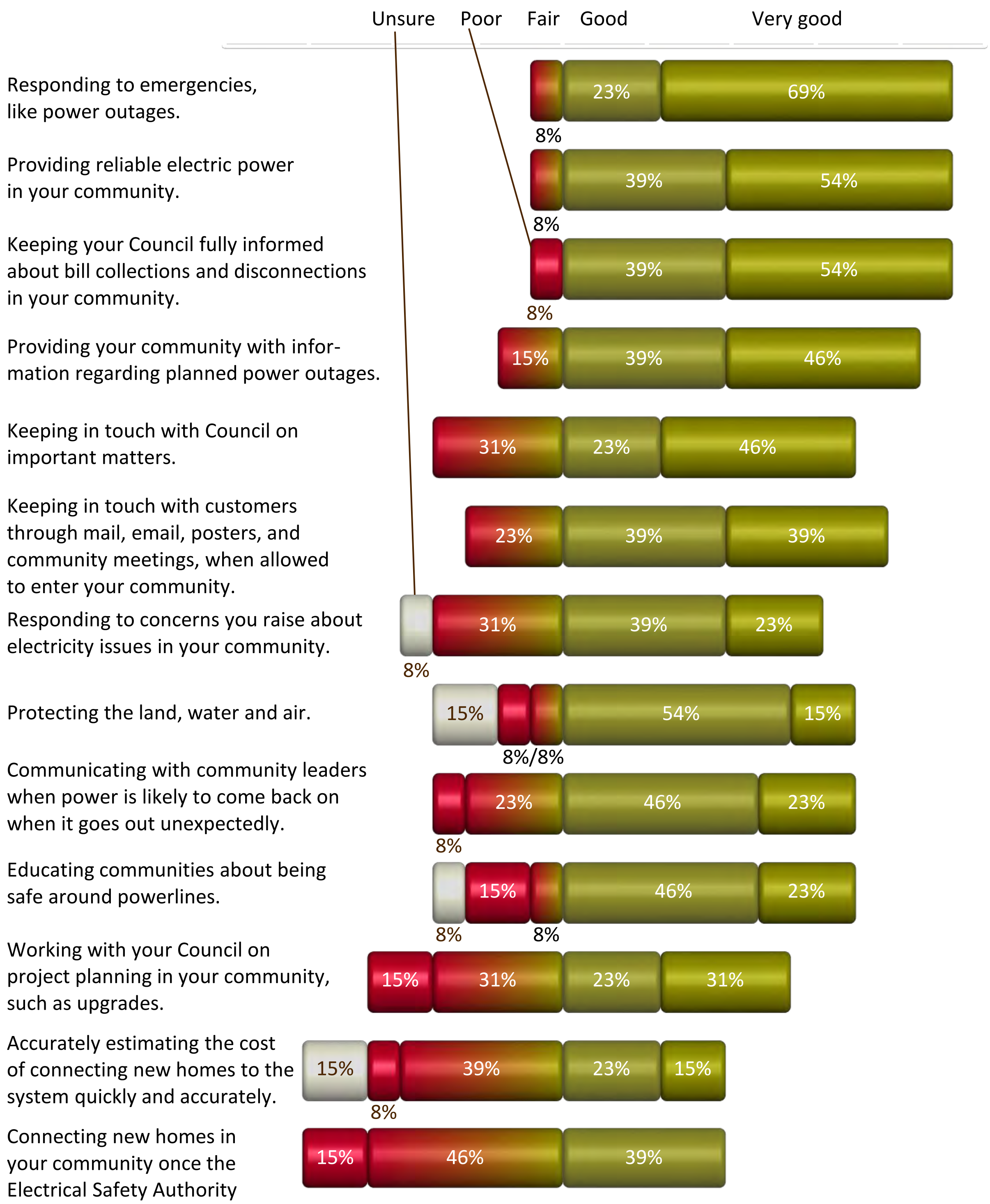
The survey tested thirteen Hydro One Remotes responsibilities, asking leaders to rate the utility as doing a very good, good, fair or poor job in each area. Hydro One Remotes earned the highest ratings for *responding to emergencies* (92% very good/good combined) and *providing reliable electric power* (93%).

Keeping Council fully informed about bill collections and disconnections earned 93% good/very good ratings and 8% poor ratings.

A majority of leaders gave the utility good/very good ratings for: *providing their community with information regarding planned power outages* (85%), *keeping in touch with customers* (78%), *protecting land, water and air, keeping in touch with Council on important matters, communicating with community leaders when power is likely to come back on after an outage, educating communities about safety around powerlines* (each 69%), *responding to concerns raised by chief and council* (63%) and *working with Councils on project planning in communities* (54%).

Fewer leaders gave Hydro One Remotes good or very good ratings for *cost estimates* (38%) and *timely service connection* (39%).

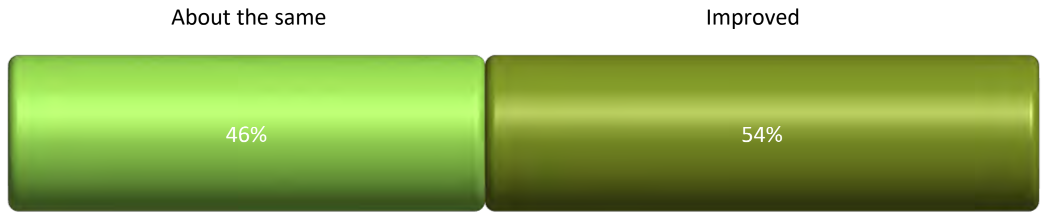
Chart 10: **Hydro One Remotes' Responsibilities**



Quality of Service

A majority of leaders feel the overall service provided by Hydro One Remotes has improved over the past five years (54%, 7 respondents), while six respondents said it has stayed the same (46%) and no one said it has worsened.

Chart 11: **Quality of Service**

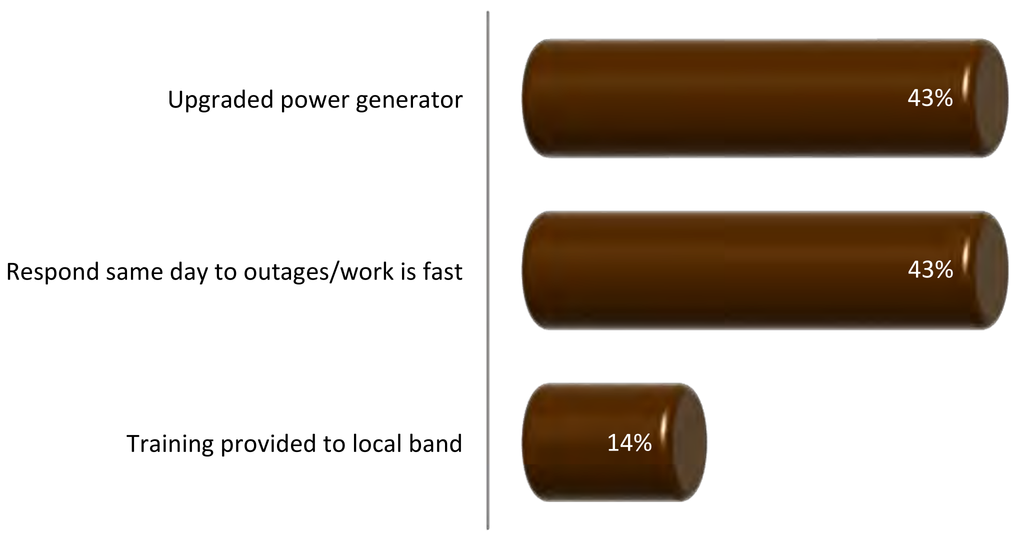


Reasons for Improvement

Among leaders who said service has improved (n=7), three mentioned each of the following: *an upgraded power generator* and *same day response to outages/fast work* (each 43%). One respondent cited *training provided to the local band* (14%).

Respondents' verbatim responses to this question can be found in Appendix A.

Chart 12: **Reasons for Improvement**



Hydro One Remotes' Strengths

Asked the one thing Hydro One Remotes does best, almost half of leaders spoke of the utility's capacity to *provide electricity to their community and maintain its generators* (46%, 6 respondents). Four respondents noted the *reliability of the service* (31%) and one each cited *communication with Council* and *providing their community the time needed to address issues* (each 8%). One leader did not answer the question.

Respondents' verbatim responses to this question can be found in Appendix A.

Chart 13: **Hydro One Remotes' Strengths**

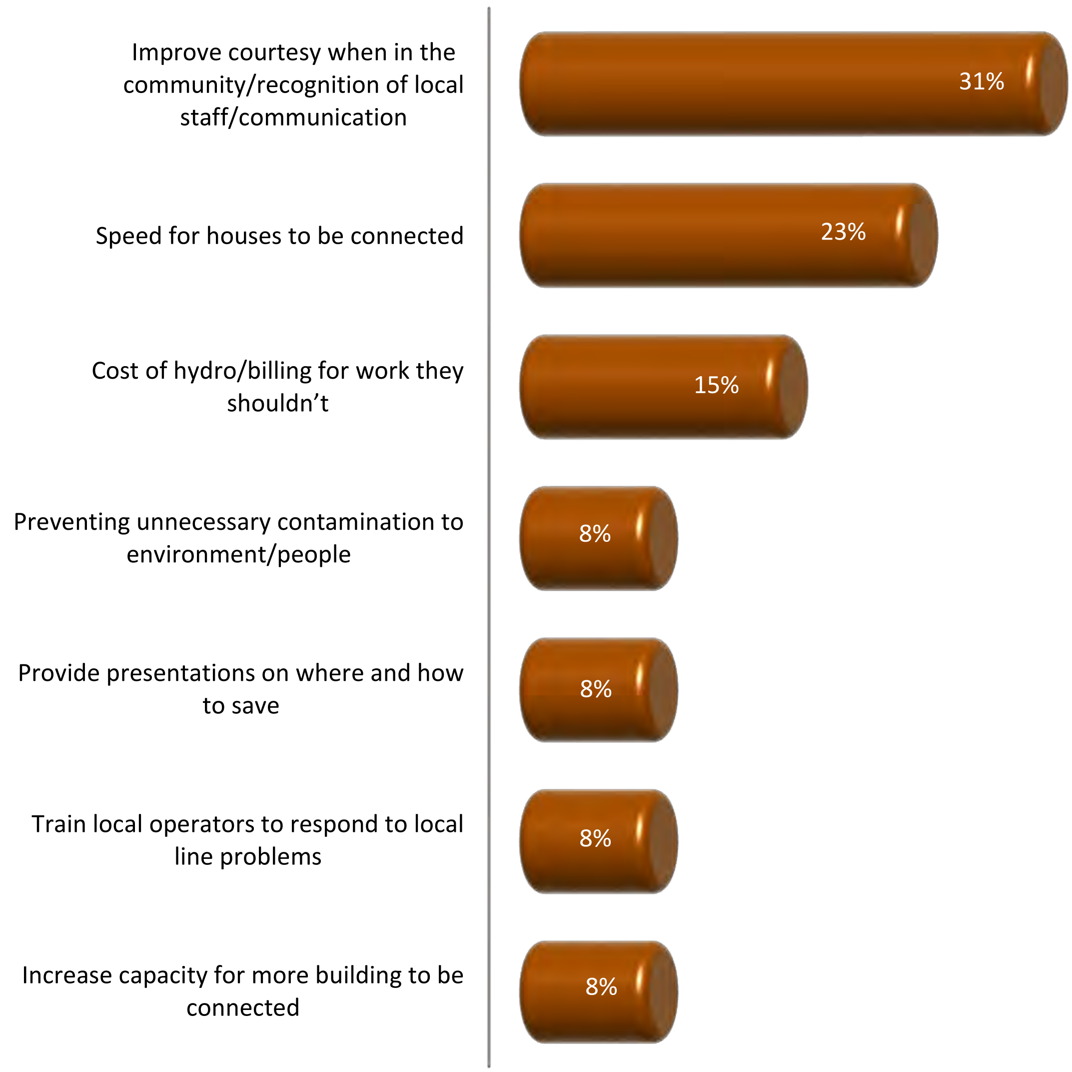
Areas of Hydro One Remotes' Service Needing Improvement

Leaders offered their thoughts on the single most important thing Hydro One Remotes needs to improve on. Four respondents spoke to the *interactions of Hydro One staff with the local community in terms of courtesy, recognition and communication* (31%). Three others mentioned the *speed with which houses are provided electrical service* (23%) and two identified the *cost of installation and provision of Hydro service* (23%).

Other areas were mentioned by one respondent and are displayed on Chart 14, below (each 8%).

Respondents' verbatim responses to this question can be found in Appendix A.

Chart 14: **Areas Needing Improvement**



Watay Powerline

A series of questions were asked of nine respondents whose communities are expected to be connected to Ontario's provincial electricity grid within the next few years via the Wataty Powerline.

Readiness for Grid Connection

Eight of nine leaders feel their community is ready to be connected to the power grid (89%), but only two of these said they are very ready (22%), while the rest feel only somewhat ready (67%). One leader concedes their community is not very ready for this change (11%).

Backup Power

Two thirds of leaders feel backup power is essential once their community is on the grid and anticipate maintaining the existing generators to meet this need (67%). Another specified a diesel generator with a 2,000+ megawatt capacity (11%) would provide suitable backup power. Two leaders were unsure (22%).

On-Grid Costs

Leaders are unclear whether being on the provincial grid with increase their Hydro costs (33%), whether they will stay about the same (33%) or be lower (22%). One respondent was unsure (11%).

On-Grid Reliability

Asked how reliable they anticipate grid-connected electrical service will be, expectations are mixed. Four respondents expect it will be less reliable (44%), three think it will be the same (33%) and one anticipates it being more reliable (11%).

Watay Timeline

Five leaders feel the current Watay schedule for their community meets their expectations (56%), while two said it does not (22%), one is unsure and another declined to answer the question (each 11%).

What Will Change On-Grid

Leaders are most likely to anticipate improved electrical capacity to connect more houses (44%, four respondents), while two expect higher Hydro costs (22%). One each mentioned less maintenance, reduced environmental impact or were unsure (each 11%).

APPENDIX A

Verbatim Responses

Q24 Hydro One Remotes is currently creating a Remote Communities website to help the company better communicate with customers. The website will have information on programs for customers and communities, community operations and more. What would you like to see on the new website?

- Programs that Hydro One has got that support First Nations.
- Make it easier to get hold of Hydro One and understand their programs.
- What work they do.
- Explain how to save on electricity bills e.g. the expense of heating with baseboard heaters. Explain how the electricity works.
- Photos of what has been happening with Hydro initiatives and the amount of energy being used in the community.
- People's comments on how to better relationships, ways people can save energy, and have information in syllabics.
- What other communities are doing with Hydro One and job availabilities.
- A place where you can have interactive activities so information is not just going one way, a social media platform.
- Where to call with questions in our language, e.g. billing and promotions.
- Information about the initiatives and programs like LEAP and OESP.

Q26 What are the main reasons why you give Remotes that assessment?

- They've sent us their protocols in advance, as well as advance notice when they're arriving. And when they're here, they follow the guidelines and protocols.
- They are careful, they social distance and they are nice.
- When they asked to come, we let essential workers come in when we had lockdowns. We need service in community, and when they were asking to come in, we all agreed to let them come. They stayed in their bubble, and contacted us first to come into the community and they stayed where they were supposed to.
- They stayed at the hydro generation site and have their accommodation site. They don't integrate with the community. They send us email when they want to come up.
- When they came, I saw them not wearing their mask. When they approached, they were not wearing a mask and staying 6 feet apart.
- They usually called. They stay away from people. They stay at the hydro compound and don't go to public places. They come in do the work, stay at compound and go.
- They called us every time they want to come. The communication went very well. They followed protocol and didn't wander in the community.
- There was proper communication. They sent fax and emails to key people in community.
- Before they come in, they contact us, with their plans, what they are doing. They are not in touch with our people. They do their business and go right back out.
- The communication they had when they had to come into community. They informed the First Nation and Council they were coming. They didn't just show up.
- They tell us when they are coming and practice protocols in the community. They have been responding very well.
- In isolated communities, we do have problems when power is out for 2 or 3 days. Within those days our food goes to waste and we've had to throw it out. While the community was closed, we had outages where nobody came. It would be good if there was something put in place where its a priority to get power up and running. The majority of people are on limited incomes or they are elders, and the food in the freezer has to get you through the month. With power outages, we as the band lose our food too and can't help out. It would be good if we had generators to keep the houses and fridges going.

Q42 What are the main reasons why you say (the overall service that Hydro One Remotes provides to your community) has improved?

- At the beginning, there was not enough generation, then they made more available. A few years ago they severed the old compound and have built a new compound and facility with a loading station available. The old system had more damage to the environment with its pump and hose system. Now, with a dock, there is less chance of spillage.
- The work is fast.
- We get more buildings hooked up, and more houses to build this summer.
- The power generator was upgraded. Before, there was no power left to create more houses.
- When we have power outages they come in right away; the same day or within a couple hours. Before it took them days to come in.
- The service and training they provide to our local band.
- The turn around time with connections and informing us regarding needs of community e.g. streetlights.

Q44 What would you say in the one thing that Hydro One Remotes does best.

- They give us electricity.
- They are very reliable.
- Putting in poles and connecting Hydro.
- When there is an emergency, like with generators, they come right away.
- Keeping power on all the time.
- Their work. When they install the poles and lines, they are doing a good job.
- Communicating with the community through Council.
- Maintaining generators.
- Reliable electricity.
- Providing power considering our location.
- Providing somewhat reliable power.
- Giving us time to address issues.

Q45 What would you say is the single most important thing that Hydro One Remotes needs to improve on?

- Continuing on with protecting unnecessary contamination to the environment and people.
- The price of Hydro.
- How long we have to wait for hook ups.
- They have to communicate with the Chief and Council when needed, when there are problems in the community with disconnections, and come and hook us up right away when we have ESA approvals.
- Train local operators to respond to local line problems.
- They need to improve their courtesy when coming into the community.
- Presentations on where and how to save, and where we can get rebates. Come in and do presentations.
- Hydro One needs to put more recognition on our local staff. Our service agreement has not changed in over 30 years. There are small incremental increases but its very small. Yet local staff continue to provide the work while the pay is disgraceful and peanuts. Local staff provide the best service to our community.
- Come and connect new houses as soon as possible once everything is approved.
- They are billing for work they shouldn't. We call Hydro Remotes and they bill us to estimate hook ups but they don't charge a nearby community that is off-reserve.
- We have more buildings that need power. We need more power from the plant to connect to new buildings and infrastructure.
- Communication when the power goes out.

Q46 Is there anything else you would like to add or comment on?

- Hydro One is doing good in the community, looking after the generators. Whenever we have something like power outage they do come right away.
- Recently we tried to add one more staff member so the 2 working don't get burned out. Their pay would have to decrease. One has been there 15 years, the other 25 years. Their pay would have to decrease to pay a 3rd operator. There is no increase in pay, yet service and the community has grown.
- Our main concern right now is waiting for houses to be connected. It's wintertime.

- $18,000 to pay them for quote to tell me how much it's going to cost for a connection impact assessment, on a project that is going to come in at about $350,000. It's all done in-house and that price is ridiculous. They talk about the Reindeer program and the streetlight retrofit. We buy the lights, they do the work, and their cost is 50% more than us getting another contractor.

- Some have 100 amp. service but can't operate a hair dryer and toaster at the same time. Microwaves and toasters will trip. The Christmas season is very hard because Christmas light will trip.

Q48 What are your thoughts on what backup power may look like in your community?

- We need back up power because of forest fires and what not. I'm hoping to utilize the generators we currently have.

- Backup power is very important. We've heard that grid line power can go out for long periods of time. Back up power can be reliable to power the community.

- We were told would not be getting backup power, and it is very disappointing.

- Generator, diesel - maybe 2,000+ megawatts.

- We need backup power.

- If we could keep the generating station as a back up, that would be good.

- Hydro is going to keep the generators already here for back up.

Q52 What do you think will change most when your community is grid-connected?

- The environment and climate change will be less damaged because of less fuels.
- Capacity. We hopefully can hook up more buildings without being capped and hopefully it will bring reliable power to the community.
- Less maintenance.
- Hydro bills will increase.
- There will be more power for the community so we don't have to be restricted.
- Reliable power and we can have buildings built to expand the community.
- We'll be able to connect more houses.
- The cost of Hydro may increase from what we have now.

Appendix D

Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities

FEASIBILITY OF USING EXISTING DIESEL GENERATING STATIONS FOR BACKUP POWER IN REMOTE GRID-CONNECTED COMMUNITIES

DECEMBER 2018

PREPARED FOR:

PREPARED BY:

REMOTE COMMUNITIES INC.

EXECUTIVE SUMMARY

Sixteen remote communities are slated for connection to the new Wataynikaneyap transmission system. The overall duration of power outages in the communities is expected to increase. Backup power generation has been considered as a way to keep yearly outage durations similar to historical values. This report finds that using existing diesel generating stations to provide backup power is practical over the first 40 years after connection to the transmission system.

TABLE OF CONTENTS

1 INTRODUCTION

Hydro One Remote Communities Inc. (Remotes) was retained by Opiikapawiin Services LP (OLSP) to prepare a report to determine the suitability of existing generation assets to provide backup power in communities that will be connected to the Wataynikaneyap Power (Watay) transmission system. Previous reports by BBA and Ontario Power Authority (OPA) estimated that each community could experience combined outage time of 3 to 7 days per year, depending on the length of the new transmission lines to the existing provincial grid. There are a few alternatives to provide backup power during transmission outages. BBA recommended that existing diesel generating stations (DGS) be used for the first few years to provide backup power. This report focuses on the feasibility of using those existing diesel generating assets for backup service.

This report was prepared with the cooperation and input of OSLP, Indigenous Services Canada (ISC), and Ontario Ministry of Energy. Their contribution was invaluable and is greatly appreciated.

2 OVERVIEW

The sixteen communities to be connected to the transmission system are shown on the following map. Seven of the communities own and operate their own diesel generating station as an Independent Power Authority (IPA). The other nine communities are powered by stations owned and operated by Remotes.

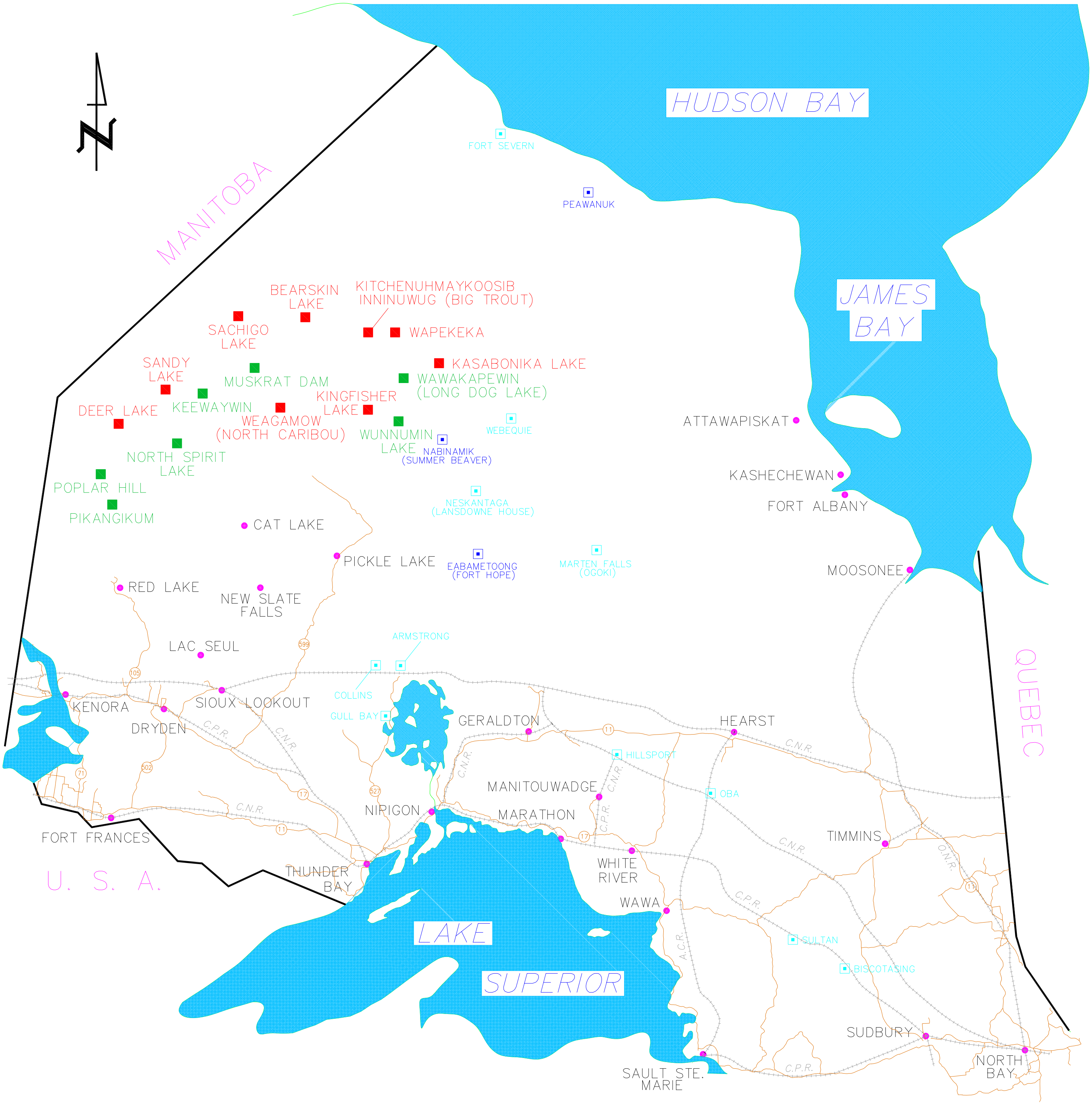
All stations are currently run in a Prime Power capacity which means they run 24/7/365 to provide the primary power supply to each community. Backup Power stations would only be run when there is a transmission system outage.

This report addresses the following:

- Development of a Service Standard for backup generation
- A 40-year peak load forecast for each community
- The suitability of each existing DGS to serve as a backup station during transmission system outages
- Modifications required to convert a Prime Power DGS to backup service
- Costs for conversion, yearly operation and maintenance, and potential future capital upgrades
- Fuel storage requirements and cost

hydro one Remote Communities Inc.

REMOTE NORTHERN COMMUNITIES IN ONTARIO



LEGEND

- TOWNS ON ELECTRICAL GRID
- HYDRO ONE REMOTE COMMUNITIES TO BE CONNECTED TO WATAY TRANSMISSION SYSTEM
- INDEPENDENT (IPA) COMMUNITIES TO BE CONNECTED TO WATAY TRANSMISSION SYSTEM
- HYDRO ONE REMOTE COMMUNITIES TO REMAIN ON DIESEL GENERATION
- INDEPENDENT (IPA) COMMUNITIES TO REMAIN ON DIESEL GENERATION

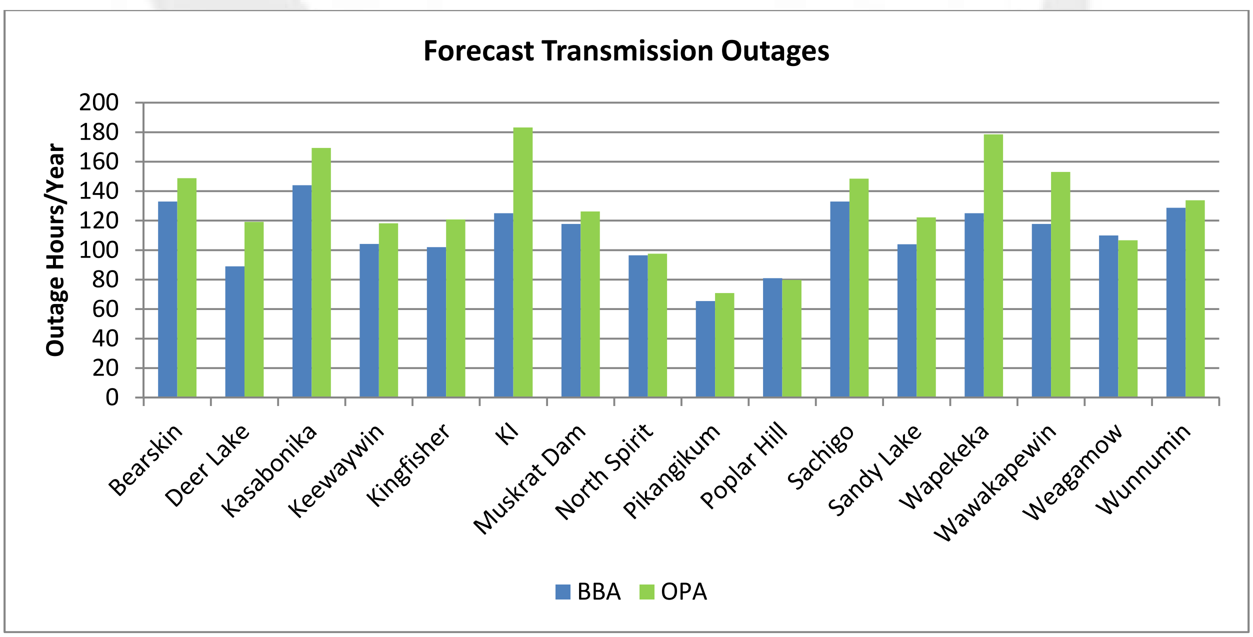
DEC 2018

4 OUTAGES

The main driver for backup generation is the forecast duration of transmission system outages over a year. Previous technical reports were completed by the OPA in their original draft technical report (released August 2014) and more recently by BBA based on Watay's current transmission system design. Both reports estimated transmission system outages for each community based on the type and length of the transmission line feeding the community. The forecasts generally agree with each other and range from almost three days of combined outages in Pikangikum (shortest transmission line) to 6 to 7 days of outages in communities fed by the longest transmission lines (see table below). Hydro One Networks provided some input for the OPA report so those numbers do reflect what Hydro One would expect for a similar line in Northwestern Ontario.

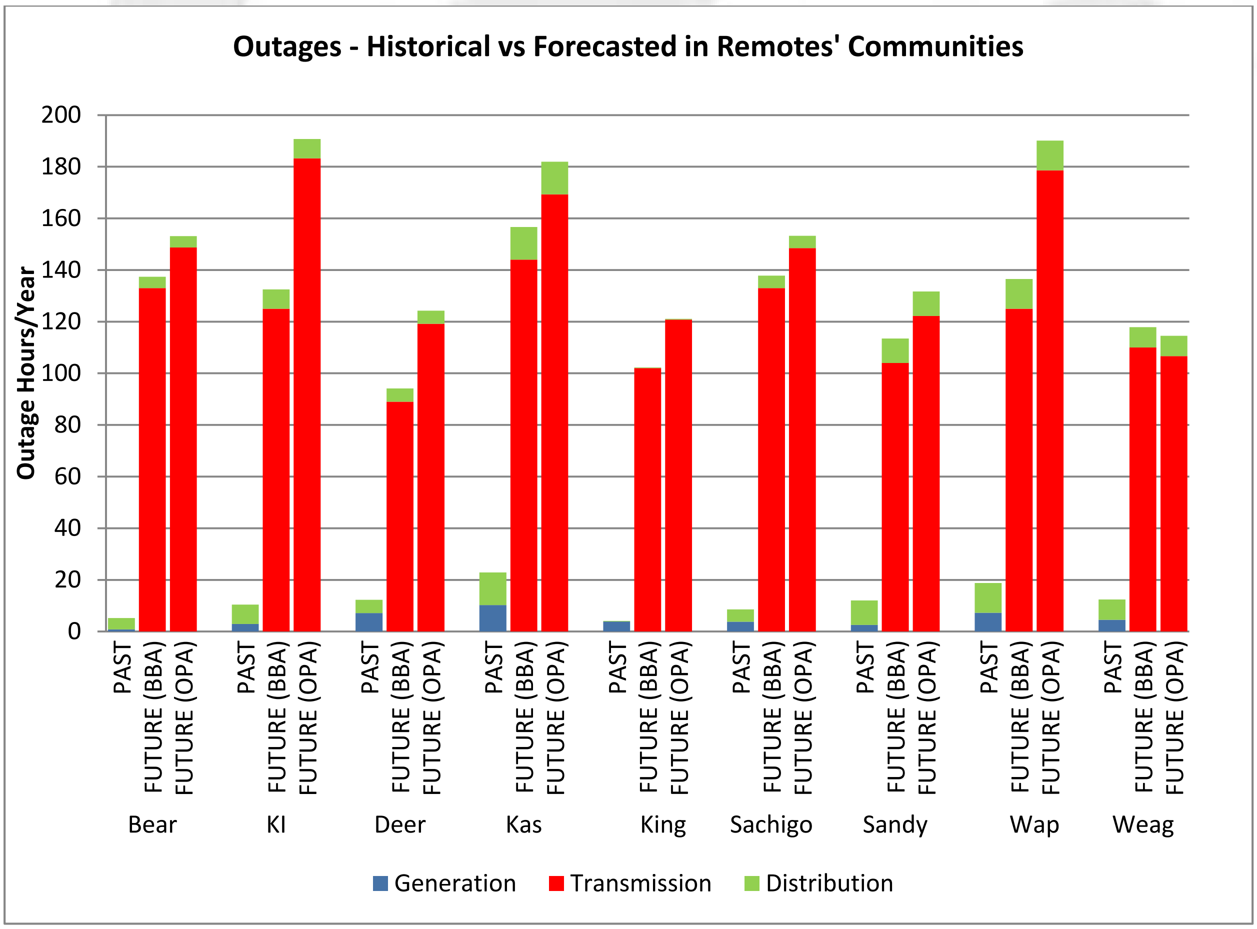
Most communities in Ontario are connected to more than one transmission line. If one line has a fault, the community can be powered by the other line. The remote communities will be connected to only one transmission line (called a radial line). Because these radial lines will be very long, there is more opportunity along the lines for outages to occur.

There are ten categories used to classify transmission outages (unknown, scheduled, loss of supply, trees, lightning, defective equipment, weather, environment, human element, foreign interference). Some types of outages happen yearly (lightning, trees). Others are very infrequent (wind storms, ice storms). To account for this, the estimated outage numbers are the expected annual long-term average. In some years there could be much less transmission outages than the estimates and in other years there could be more.



Historical outage data is only available for the Remotes' communities. A 5-year average (2013-2017) was used to represent historical outages in Remotes' communities. Those were broken out into generation outages (caused by the DGS) and distribution system outages. The distribution system outages will still occur when the communities are connected to the transmission system. Typical distribution system outages are caused by a tree falling on a line, a car hitting a pole, or a house fire.

The following chart shows an increase in power outage duration expected in Remotes' communities when they are connected to the transmission system. Having a local backup station would reduce the outage duration to near historical levels in Remotes' communities. A backup station would likely result in a decrease in outage duration in IPA communities over their historical levels.



5 LEVEL OF SERVICE STANDARD

A Level of Service standard is required to quantify that the existing DGS assets are capable of providing suitable backup generation. This level of service was developed by considering community requirements (see Appendix 7), standard backup power requirements, and Remotes' experience in diesel generation.

1. RESPONSE TIME – The average time over the course of the year for backup power to come online will be within two hours of a transmission system outage. A two hour goal was selected because some communities indicated during consultation with OLSP that the battery backup in communications equipment is sufficient for 2-4 hours. This may be for cell phone equipment as Bell Canada has confirmed that their equipment has backup ranging from 14 to over 60 hours.

   There are also health and safety concerns in some communities that require timely power restoration. Some home based medical equipment (ie. home dialysis, sleep apnea machines) reportedly have a backup time of 2 hours.

   Note that this response time applies only to the backup power supplied by the DGS. This is not related to Remotes' response time for distribution outages. Distribution response times are expected to remain the same.

2. FUEL STORAGE – Fuel will be replenished using the yearly winter road. The amount of fuel will be adequate to supply the following requirements for one complete year:
   - Fuel for monthly generator testing (1.5 hours per month)
   - Fuel for estimated transmission system outages (based on BBA estimate) at an average load of 70% of the peak load.
   - Fuel for a 5-day outage in January to allow enough time to fly in additional fuel if the outage is expected to last longer. Five days was chosen because if a number of communities are affected, it could take a few days to get fuel to all of them based on availability of fuel transport planes.

3. TROUBLE RESPONSE – If the generating station fails to provide backup power when needed, a repair crew will be dispatched. The timeline for repair will be influenced by expected duration of outage, outdoor temperature, and ability to fly into the community. If backup power in more than one community fails to operate, response time could be delayed.

6 STATION ASSESSMENTS

To determine the suitability of each DGS to serve in a backup capacity, assessments of the stations were required. These assessments looked at the condition of the gensets, switchgear, auxiliary components, fuel tanks and systems, buildings, yards, and signs of contamination. The assessments were not intended to ensure a station was up to a standard that Hydro One would expect for a new station, but rather a level that would be suitable for reliable backup service for many years to come. An overview for each community is included in this report (Appendix 1). Each overview gives specifics for the DGS and details what would be required for conversion to a backup station.

6.1 IPA STATIONS

Assessments were done at five of the IPA communities. The Pikangikum DGS is slated for removal, so no visit was required. Travel to Wawakepewin is difficult so pictures and documents sent by others were used to assess the DGS.

Remotes had previously surveyed the Wunnumin DGS in 2016 and the Muskrat Dam DGS in 2017 as part of a different project. Those surveys were used for this assessment. Remotes visited the stations in Keewaywin, Poplar Hill, and North Spirit Lake in early September 2018 to gather relevant information. The station in Poplar Hill burnt down so only the bulk fuel system and the trailer genset powering the community were assessed.

The IPA gensets are almost all newer vintage with low hours. Many of the stations have newer switchgear. All have modern fuel storage and delivery systems. The only concern was visual signs of contamination at some of the stations.

Contamination at the IPA stations is an issue beyond the scope of this report. The community summary sheets give some detail on the visual contamination seen at some sites. Optional costs are given in Section 12.3 to provide backup generation using new generators at a new site in lieu of operating at a potentially contaminated site.

Overall the IPA stations are suitable for backup service with some minor alterations that are required for all stations. Future ownership of the IPA stations is beyond the scope of this report and requires consultation with the communities and other involved parties. At the very least, Remotes would be willing to operate and maintain the stations to offer back up power as a contractor to the First Nation, ISC, or Watay.

6.2 REMOTES STATIONS

Remotes' DGS's vary in design and vintage but overall are very similar. They all require basically the same changes for conversion to backup service. All are in good condition and have been well maintained. Some engines have higher hours than IPA gensets, but still have much more serviceable life remaining than will be required for backup.

7 FORECASTS

7.1 LOAD FORECAST

A peak load forecast was created to determine how long the existing DGS assets could meet community demand (Appendix 5). The forecast gives the expected peak loads for the 40 years after the communities are connected to the transmission system.

Communities serviced by Remotes have not had any restrictions on service size for a long time whereas some IPA communities still have restrictions. That could lead to a higher growth rate in the IPA communities once those restrictions are lifted. IPA communities could also see a move to more electric heat since rates will be lower. Rates in the Remotes serviced communities will be comparable to current rates for residential, so there shouldn't be much increase in electric heat in homes. However commercial buildings will have a lower rate and may convert to electric heat.

In Remotes' communities that will be connected, the historical average annual increase in the peak load is 2.7%, calculated from 2001 to 2018. Recent peak load data from the IPA communities is not available, but based on older data, their growth rate has been noticeably higher than the Remotes serviced communities.

There was a request to include a 4% load growth in the forecast to match what has been used in previous transmission system calculations. This report will use both the 4% growth requested and the 2.7% historical growth in Remotes serviced communities.

7.2 LOAD FORECAST RESULTS

A graph showing the load forecast for each community is included in the community summary sheets. The generation and electrical limits of each station were used to determine in which year the demand will exceed the station's capability. The generation limits were set as the prime rating of all the gensets combined. The electrical limit was set as the kVA limit of the switchgear and transformers assuming that the power factor is close to unity.

Depending on the growth rate, the current DGS assets are suitably sized to provide full backup into the 2030's and possibly closer to 2050. Exceptions are a couple of communities that reach their electrical limit sooner.

It is important to underscore that once the community peak load exceeds the station limits, the station is still suitable for backup power for many years thereafter. The peak load occurs for only minutes per year. The likelihood that the peak community demand will coincide with a transmission system outage is slim for the first few years after the station limit is reached. It is likely that the station will be able to provide full backup for a few years after the station limit is exceeded.

7.3 FUEL FORECAST

The fuel requirements for backup service were calculated based on the requirements previously outlined in the Level of Service Standard. The number of bulk tanks required to store that amount of fuel in 2061 was calculated for the 4% growth rate and is identified in the community summary sheets. Those tanks would remain at the station. Any tanks not required could be relocated and repurposed for use in the community.

The fuel requirements were calculated for each community, accounting for testing fuel, fuel for transmission outages (based on an average load equal to 70% of the community peak demand), and contingency fuel for a 5-day outage in January (based on an average load equal to 85% of the community peak demand). Should the contingency fuel not be used, it would remain in the tanks for backup use in the next year. Diesel fuel can be stored for at least two years without adding conditioner.

Appendix 6 gives the fuel forecast for each community by year, using both the 2.7% and 4% growth rates. One forecast includes the 5-day contingency fuel as that is the basis for fuel storage requirements. The other forecast does not include the contingency as that is what fuel costs are based on.

8 STATION CAPITAL MODIFICATIONS

For the generating stations to be operated in a backup capacity, they require some relatively small changes. Some are required prior to entering backup service. Others can be completed in the short term.

8.1 PRIOR TO BACKUP SERVICE

8.1.1 Building Heat

The generating buildings must be kept at a suitable temperature to protect electronics and equipment.

All the IPA stations, other than Wunnumin, currently use electric unit heaters. Remotes' stations and Wunnumin use waste heat from the running generator to heat water that circulates through the building (Secondary Heat System). Unit heaters in each room use the heated water to provide building heat. Once a station is converted to backup, an engine will no longer be running continuously to provide heat to the secondary heat system.

An electric or oil-fired boiler could provide heat to the secondary heat system. However the secondary heat system does require regular maintenance (coolant changes, pump maintenance) and a boiler would add to that. Therefore electric unit heaters would be the most reliable source of building heat.

As part of the switch to electric heat, the secondary heat system would be drained of coolant to eliminate the chance of a spill. The piping system itself would be left in place until the entire station is decommissioned in the future.

8.1.2 Engine Block Heat

Diesel engines are kept at a warm temperature so they start easily and so they don't require a long warm up period before they can be loaded. The IPA stations currently use electric block heaters for this purpose. Remotes' engines are heated by the secondary heat system. Since that system will no longer be in service, electric block heaters will require installation.

8.1.3 Programming

The computer programs that run the stations will need some modification to add some new operating logic for backup service.

8.1.4 Station Service

The station will require power from the distribution system for heat and lighting. One option is to back feed through the main breaker. Another option is to install a new distribution service for the station. This will be determined once the fault levels are analyzed. Note that station service will be metered at the commercial rate.

8.1.5 Protections

The protections on the DGS connection to the distribution system will need some modification based on fault levels available to the station. If station service is provided through the main breaker, it will also affect the protections.

8.1.6 Communications

Reliable communications are required to effectively monitor and operate a backup station. A fibre optic internet connection will be used if it is available at each DGS. If it is not available, satellite communication will be used. Monthly cost for fibre and satellite are almost identical. They have been included in the operating costs for each station.

8.2 SHORT TERM

8.2.1 Bulk Fuel

Bulk fuel storage tanks that are not required for backup storage will be available for removal and use by others. If they are left on site, they will be prepared for long term storage to preserve them for potential future use. This can be completed anytime within the first year of the station becoming a backup.

8.3 LONG TERM

8.3.1 Generating Equipment

No large capital expenditures to the existing generating equipment are expected. When a community's demand reaches the station's limits, the station will still be able to provide full power for most of the year. It will just be limited at certain times in the winter when the load is particularly high. Most communities will not reach this point for 10-20 years after being connected to the transmission system. At some point, a decision will be required to determine how to address outages that exceed the station capacity. Some options are:

- Use switches in the community to enact rolling blackouts. This would mean that part of the community would be powered to provide heat while another part of the community is kept dark. After a certain period of time, the power is switched from one part to the other.
- Another possibility is for the community to enact some sort of demand management program during transmission outages whereby residents are encouraged to conserve energy so that everyone can have backup power for necessities.
- If complete backup power is still required during peak loads, a new generator could be installed. It is recommended to standardize on one genset model and size for all future genset installations. A 2MW containerized genset with its own switchgear would be more cost effective than replacing a genset or switchgear in the DGS. It should be installed at the DGS to make use of existing bulk fuel storage, but would have its own connection to the distribution system rather than connecting through the DGS switchgear and transformers.

8.1.7 Auxiliaries

There are some minor capital costs that will occur occasionally. Buildings typically require some maintenance every few years to ensure they continue to protect their contents from the environment. Computer equipment (PLC and SCADA that automate the station) will become obsolete over time. Capital costs every 10 years to account for these sorts of requirements have been included.

9 OPERATIONS & MAINTENANCE REQUIREMENTS

9.1 MAINTENANCE

Leaving engines and equipment sitting idle for long periods is actually harmful to them. Often they won't start or perform as intended. Engines and moving equipment should be exercised regularly. It is recommended that all gensets and auxiliary equipment be run unloaded for 1.5 hours every month. This monthly run may be initiated locally, by the station programming, or remotely from Thunder Bay. These runs will provide some confirmation that the station is ready to provide backup power.

Each station will require a thorough yearly inspection and maintenance. Many checks should be completed once per year to ensure that a station remains reliable. Based on information from Remotes' maintenance department, these checks are expected to take two weeks every year per station. The depth and frequency of the station checks would be reviewed after a couple of years of backup operation and adjusted accordingly. The proposal is to split the two weeks of maintenance into two one-week trips about six months apart.

Gensets and other power equipment are usually tested occasionally at close to their maximum capacity to ensure they are capable of that capacity when required. Use of load banks is not intended for this purpose. Rather it is assumed that these verifications can be performed when the station is used for backup. However if community demand during backup service does not allow for proper load testing at least once per year, this issue should be re-visited and load bank testing should be considered.

Maintenance service intervals would follow what Remotes currently does for gensets in prime power service. Those intervals are based on manufacturer's recommendations. The number of hours placed on the gensets should be low enough that they will never require a major overhaul. However if a genset does accumulate enough hours to trigger an overhaul, the overhaul costs will have to be weighed against other alternatives on a case by case basis. The overhaul could be deferred or a new containerized genset could be installed.

9.2 OPERATION

The stations could be run remotely, but some operational aspects still require the on-site presence and expertise of a local operator. Since the station is not going to run constantly, the workload is not as high as with a prime power station. There will be no oil changes for the operator to do, less daily checks, etc. However there will still be regular fuel system checks that are mandated by code. Site security (locked doors and gates) is also something that must be done locally. A local presence during a backup event is also extremely helpful.

An operator will still require regular training. This has been accounted for by including a cost for a trainer during one of the two maintenance weeks each year.

Since Remotes expects to be operating the distribution system in each of these communities, provisions for accommodations (staff houses) and transportation in the communities are expected to be in place. Costs for those items will be covered by the distribution system budget.

10 LOCAL EMPLOYMENT OPPORTUNITIES

The operator position is the only real opportunity for local employment associated with a backup station. At this point, it is expected that the amount of time an operator will be required to look after the DGS will be 20 hours per week or less.

The only other employment associated with backup power is the three person maintenance crew dedicated to the backup stations. These positions will be certified trades positions (heavy duty diesel mechanics and industrial electricians). They will be based in Thunder Bay at Remotes' Service Centre. It may be possible in the future to explore having these positions filled by community members that have gone through Hydro One's apprenticeship program or a similar apprenticeship program if one is offered through Watay.

11 ADDITIONAL BENEFITS

Some critical infrastructure in the communities already has emergency power (ie. nursing stations). Other critical infrastructure is slated to get emergency power in the near future if it doesn't already exist (water plants, wastewater plants, lift stations, schools, communications equipment, airports, fire halls). Each installation is costly and requires regular maintenance to ensure it will work when needed. There have been instances where emergency generators would not start after sitting idle for long periods. There is also increased environmental risk in having fuel stored at multiple locations in the community.

Using the DGS as backup could eliminate the need for emergency power during transmission system outages, but not during distribution system outages. If a critical infrastructure location can withstand the length of a typical distribution system outage, but not a lengthy transmission outage, using the existing DGS for backup could be a cost effective alternative to installing and maintaining a dedicated emergency generator at that location.

12 COSTS

12.1 COST BREAKDOWN

Costs were estimated for the initial DGS conversion to backup, plus Operation & Maintenance and Capital costs for 40 years of service. Details of the costs in each of those areas is given below.

Initial Conversion

Costs to cover the work outlined in Section 8.1. The IPA communities have some additional costs to allow for inspection of their generators and equipment before they enter backup service. These costs were allocated over the first three years as that is the expected timeline to get all the communities connected to the transmission line.

Operation & Maintenance

This includes, costs for fuel, electricity for heating and lighting, monthly communication fees, operator labour, maintenance and training labour, engine fluids, one week at site for emergency repiars, and flights for site work.

Sustainment Capital

The stations will require some capital investment every few years for building repairs, replacement of obsolete equipment, etc. This cost has been applied to each station every ten years.

Capital Upgrades

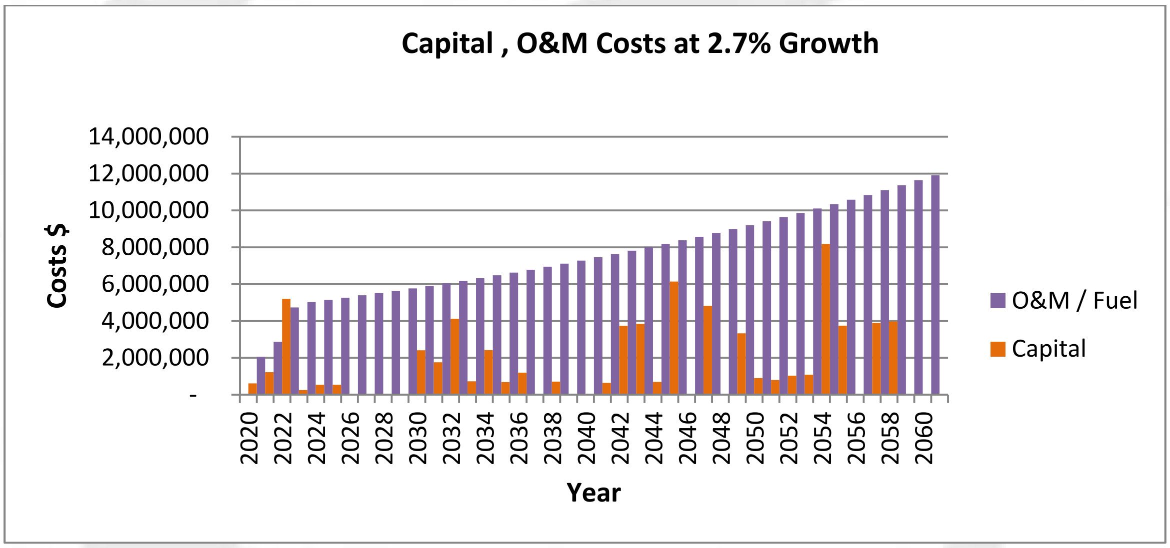
Future investment to increase the electrical or generation limits of the stations. Electrical upgrades are assumed to be replacement/upgrade of the existing switchgear or transformers. Generation upgrade costs are for the addition of a 2MW trailerized genset with its own switchgear and transformer that will run in parallel with existing equipment.

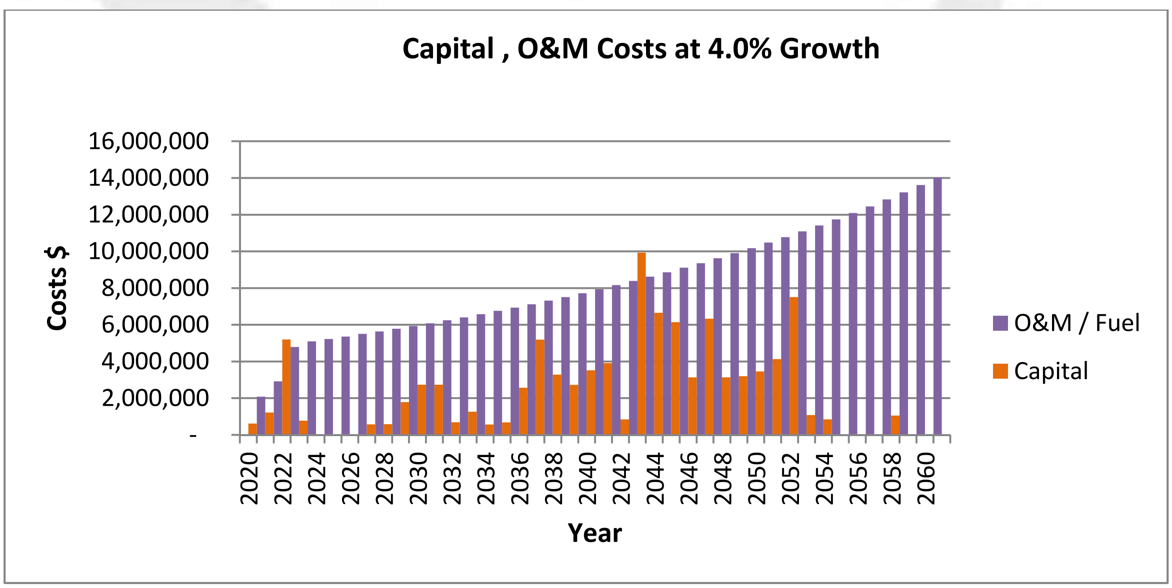
12.2 COST SUMMARY

Cost summary spreadsheets are included in Appendix 2 and Appendix 3. Appendix 2 includes all costs for 40 years of operation including capital upgrades required to provide full community backup. Appendix 3 includes all costs other than the capital upgrades. Both summaries are calculated using 2.7% and 4% load growth. The load growth affects the fuel usage and the year in which station limits are reached. An escalation factor of 2% has been used to account for inflation. An accompanying spreadsheet in Appendix 2 gives supporting rationale for the O&M and Capital costs.

With no capital upgrades (Appendix 3 summary), there would come a time where the station could not provide full backup power to the community during times of peak demand. The station would still be able to provide full backup for much of the year and partial backup at other times.

Costs are also summarized in the following graphs. The O&M costs are relatively steady and mostly increase due to escalation. The capital costs vary significantly from year to year depending on when stations require capital upgrades.





12.3 CONTAMINATED SITE ALTERNATIVE

Some of the IPA communities could have contamination that could present an issue for operating as a backup station. If contamination becomes an issue, the backup power could be provided using a new trailerized generator on a different site in the community. That new site would need to be prepared with a gravel base and security fencing. Some of the existing bulk fuel tanks would be moved to that site and connected to the new generator. The existing station could then be decommissioned. The cost to install this new backup scenario is estimated to be $2.7 million per community.

12.4 INITIAL 10-YEAR COST

The recommendations in Section 15 discuss providing backup power until 2030. Appendix 4 shows a breakdown of the costs for that period of operation. Some capital costs are required for transformer upgrades. Those upgrades could be deferred if partial backup is acceptable in those communities during periods of high demand.

13 NEXT STEPS

The next steps to prepare for backup generation using existing DGS assets are as follows:

1. In IPA communities, Remotes' operation of backup stations requires that Remotes be the licensed distributor in the community. IPA communities have requested that Remotes be their distributor, but this needs to be confirmed before Remotes can prepare to operate the IPA stations.
2. Ownership, operation, and liability limitations of the IPA stations requires discussion amongst all the involved parties (Community, Remotes, Watay, and Indigenous Services Canada). If DGS backup is approved, this discussion should happen immediately thereafter as it could take some time to reach an agreement, particularly concerning any potential contamination liability. If contamination becomes a roadblock to reaching an agreement, an option is to operate containerized gensets at a new site.
3. Funding for backup power for all communities needs to be determined.
4. If backup power is approved, it should be added to IESO's Remote Community Connection Plan or similar to ensure that the work that must be completed before the stations enter backup service is appropriately scheduled.

14 CONCLUSION

Since transmission power outages are anticipated to be between 3 to 7 days per year on average, local backup generation is a logical investment to prevent lengthy outages that could cause health concerns, hardship, equipment damage, and even evacuation of the communities. Existing backup diesel generating stations can be easily repurposed to serve as the local backup with minimal investment. Their ongoing operating and maintenance costs are quite low. This makes existing diesel generating assets a logical choice to provide backup power.

15 RECOMMENDATION

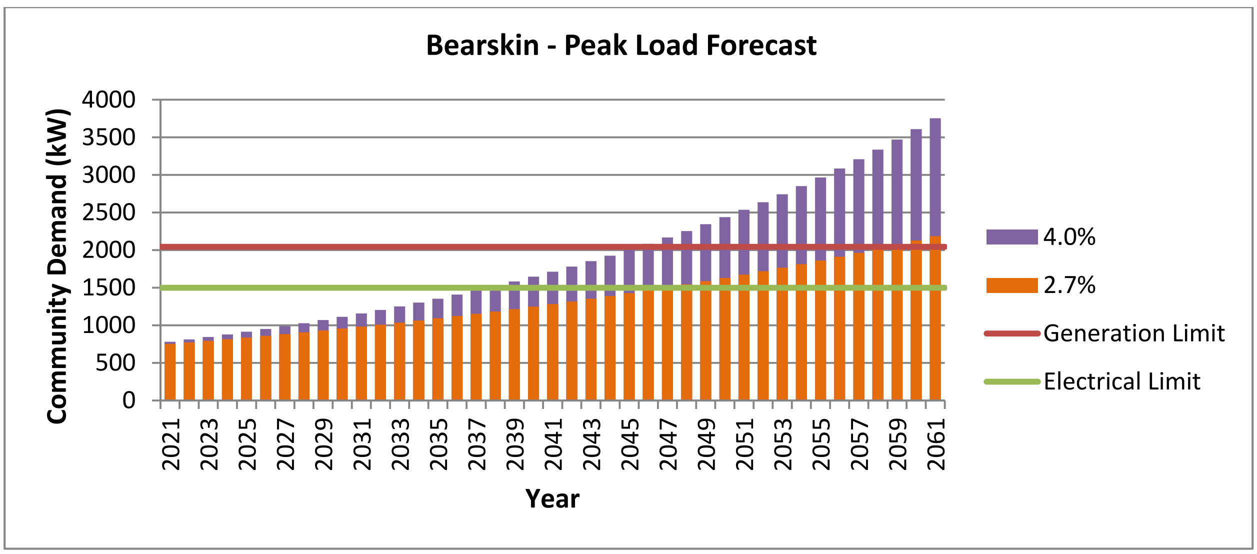
Only actual operation of the transmission system will determine its true reliability. It is recommended that the existing diesel assets be designated for backup use until 2030 as only minor capital investment is required in that timeframe. Four stations (Kasabonika, Keewaywin, North Spirit Lake, Weagamow) could require electrical upgrades depending on load growth. A few other stations could approach their electrical limit, but that would be so close to 2030 that those upgrades could be deferred. No generation upgrades would be required.

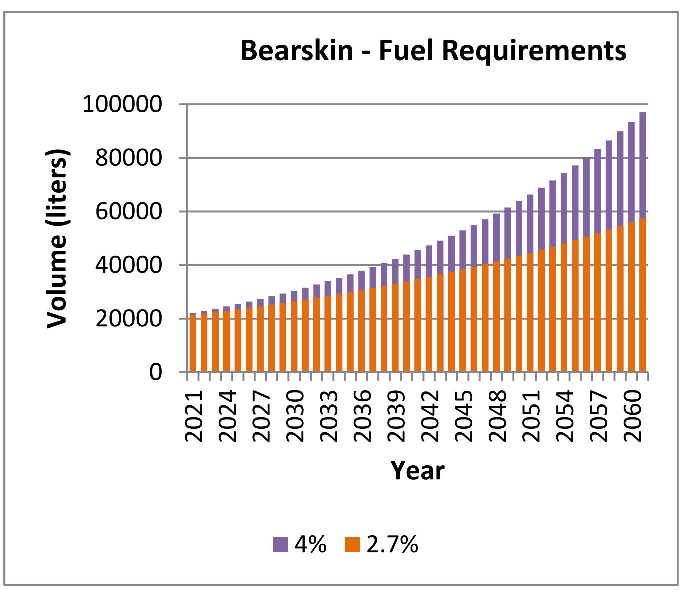
If the transmission system goes into service in all communities by 2023 as anticipated, a 2030 timeline will allow for proper assessment of the transmission line reliability and give a good indication of actual load growth. Near the end of this initial commitment, a review will be required to determine if continued backup is required and financially feasible. If load growth proves to be on the low end of what's expected, the stations could provide full backup for a few years beyond 2030 without requiring any large capital investments.

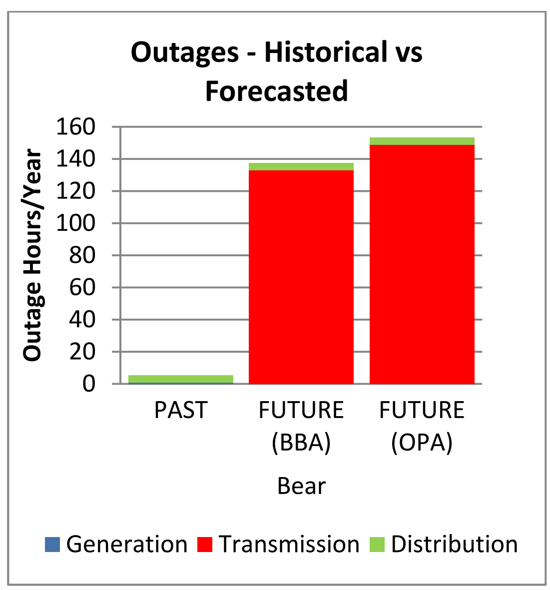
APPENDIX 1 – COMMUNITY SUMMARY SHEETS

Bearskin Lake DGS Summary

Current Configuration			
Genset Model	Cat C27	Cat C15	Cat 3512B
Genset Rating (kW)	619	410	1015
Genset Speed (rpm)	1800	1800	1200
Genset Hours	50,000	8,000	14,000
Number of fuel tanks	6		
Total bulk fuel storage (L)	290,000		
2018 Peak Demand (kW)	695		
Generation Limit (kW)	2044		
Electrical Limit (kVA)	1500		
Number of 50,000L tanks required in 2061	4		







Summary
The Bearskin DGS is in excellent condition. The station has been very reliable with negligible generation outages. Two gensets will have low hours when the community is connected to the transmission line. The C27 is scheduled for replacement in 2019 so it too will have low hours.

The station is well sized to provide full backup until 2045 or beyond. The initial investment required to convert to backup is minimal.

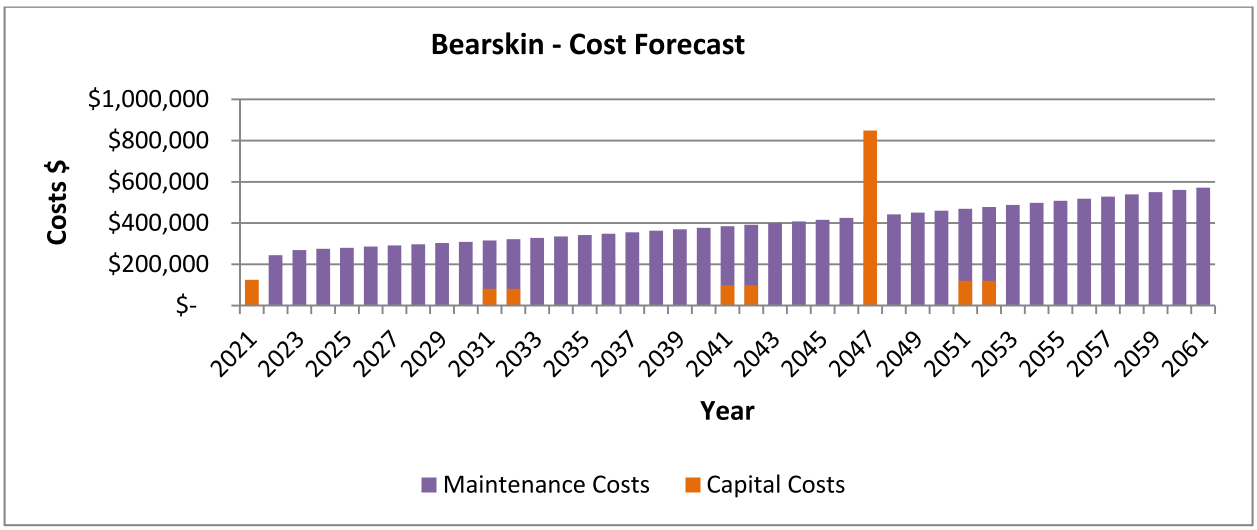
Prior To Backup Service
Convert building heating to electric, install electric block heaters, dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

Short Term Requirements
Mothball two redundant bulk tanks or remove them for use elsewhere

Potential Long Term Requirements
Uprades to the electrical equipment around 2040 would increase the capability of the station for close to 10 years until the generating equipment becomes a limitation.

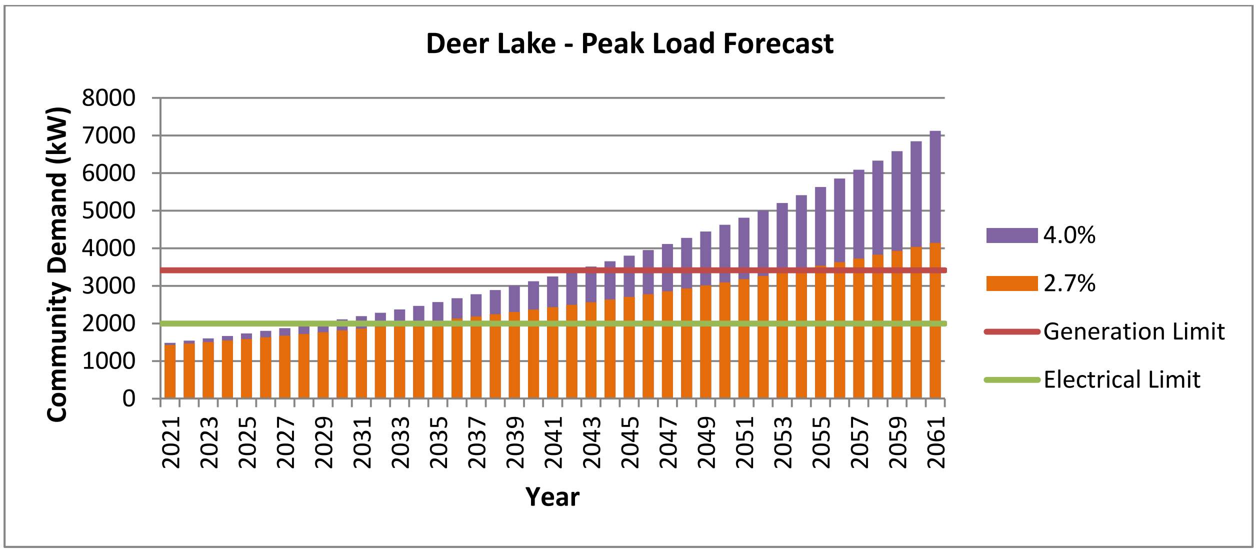
A future generation upgrade would consist of installing a 2MW containerized unit to run in parallel with the DGS. That would satisfy demand beyond 2061.

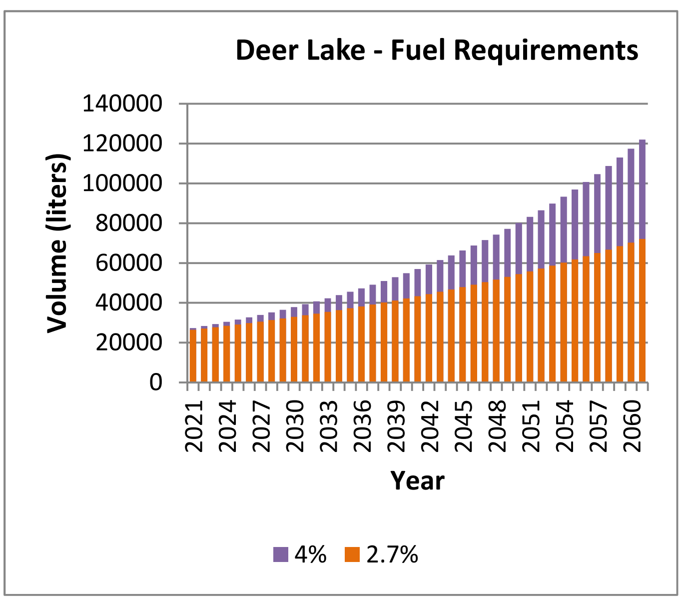
Cost Summary (2.7% growth)

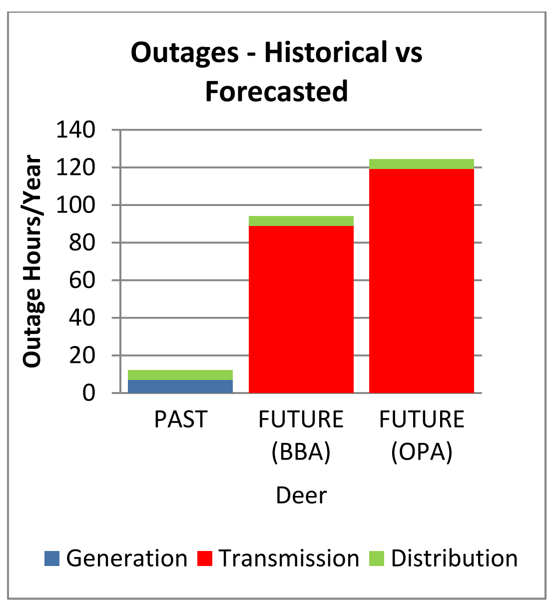


Deer Lake DGS Summary

Current Configuration			
Genset Model	Cat 3516B	Cat C27	Detroit 12V4000
Genset Rating (kW)	1500	635	1280
Genset Speed (rpm)	1200	1800	1800
Genset Hours	1,500	13,000	42,000
Number of fuel tanks	6		
Total bulk fuel storage (L)	276,000		
2018 Peak Demand (kW)	1319		
Generation Limit (kW)	3415		
Electrical Limit (kVA)	2000		
Number of 50,000L tanks required in 2061	7		







Summary
The Deer Lake DGS is in excellent condition. The overall duration of generation outages is low. Two gensets will have low hours when the community is connected to the transmission line. The Detroit genset is slated for replacement in 2022. That could be affected by the timeline of the transmission line connection. In any event, the unit would be in a state where it would be reliable for backup service.

The generation portion of the station is sized to provide full backup until the mid 2040's. The electrical portion is more restrictive but is suitable until around 2030. The initial investment required to convert to backup is minimal.

All bulk fuel tanks will remain for future use.

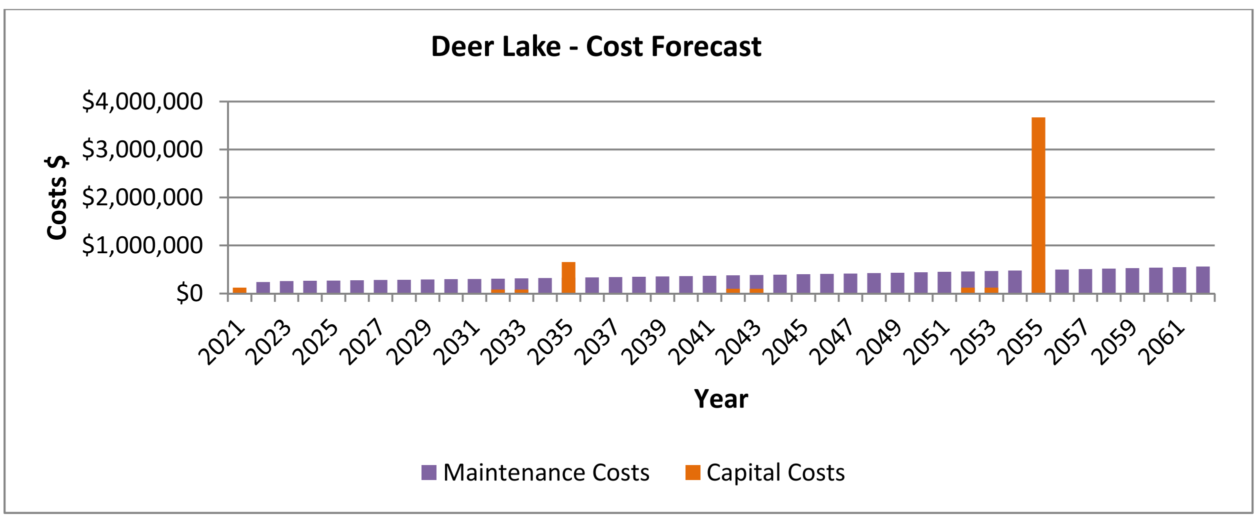
Prior To Backup Service
Convert building heating to electric, install electric block heaters, dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

Short Term Requirements
None

Potential Long Term Requirements
Uprades to the electrical equipment around 2030 would increase the capability of the station for over 10 years until the generating equipment becomes a limitation.

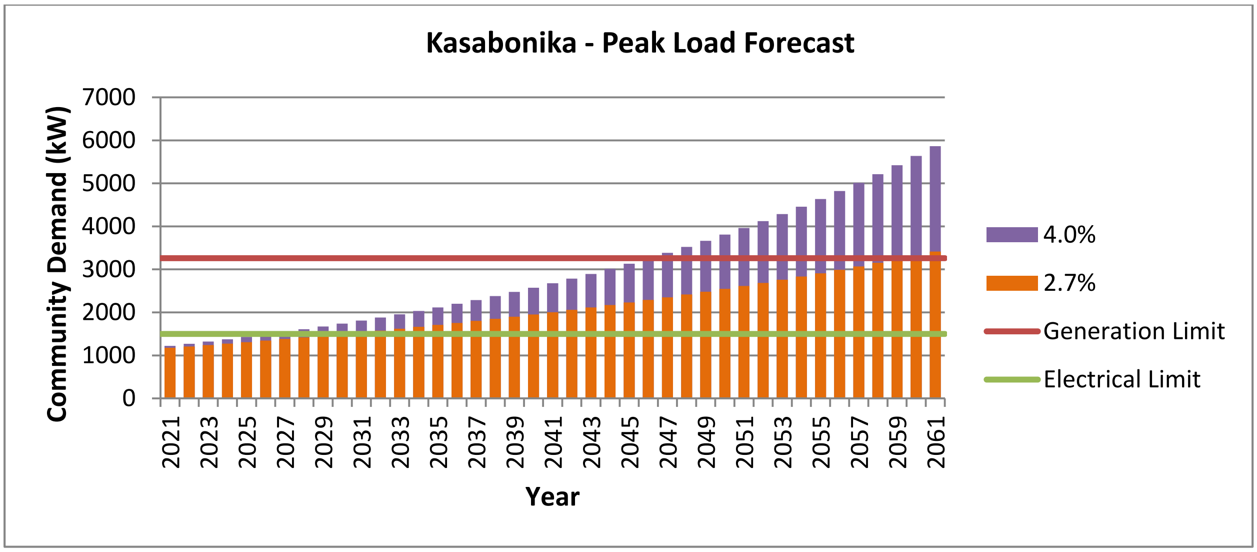
A future generation upgrade would consist of installing a 2MW containerized unit to run in parallel with the DGS. That should satisfy demand until 2061.

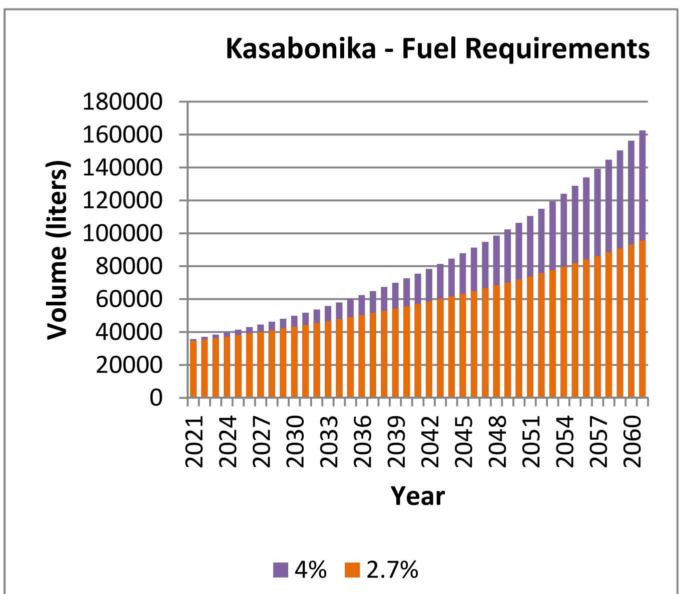
Cost Summary (2.7% growth)

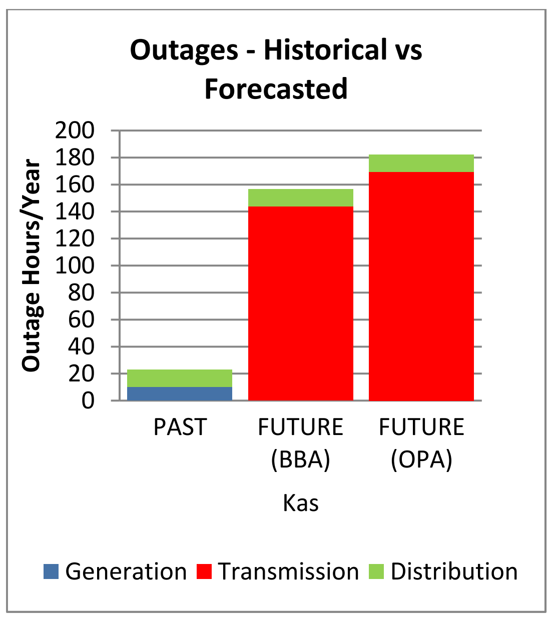


Kasabonika Lake DGS Summary

Current Configuration			
Genset Model	Cat 3516	Cat 3516B	Cat C27
Genset Rating (kW)	1125	1500	635
Genset Speed (rpm)	1200	1200	1800
Genset Hours	84,000	3,500	22,000
Number of fuel tanks	6		
Total bulk fuel storage (L)	348,000		
2018 Peak Demand (kW)	1086		
Generation Limit (kW)	3260		
Electrical Limit (kVA)	1500		
Number of 50,000L tanks required in 2061	7		







Summary

The Kasabonika DGS is in good to excellent condition. The C27 and the control room are in the oldest part of the station but it is still in good shape. The 1125kW unit is in a modern part of the building and the 1500kW unit is in an addition added in 2015. The overall duration of generation outages is low. Two gensets will have plenty of life left when the community is connected to the transmission line. The 1125kW unit has an expected life of 120,000 hours, and is scheduled for replacement in 2024 but replacement is unlikely if it is only going to serve as backup. The existing genset would undergo proper maintenance to continue operating as a backup.

The generation portion of the station is sized to provide full backup until close to 2050. The electrical portion is more restrictive but is suitable until the late 2020's. The initial investment required to convert to backup is minimal.

All bulk fuel tanks will remain for future use.

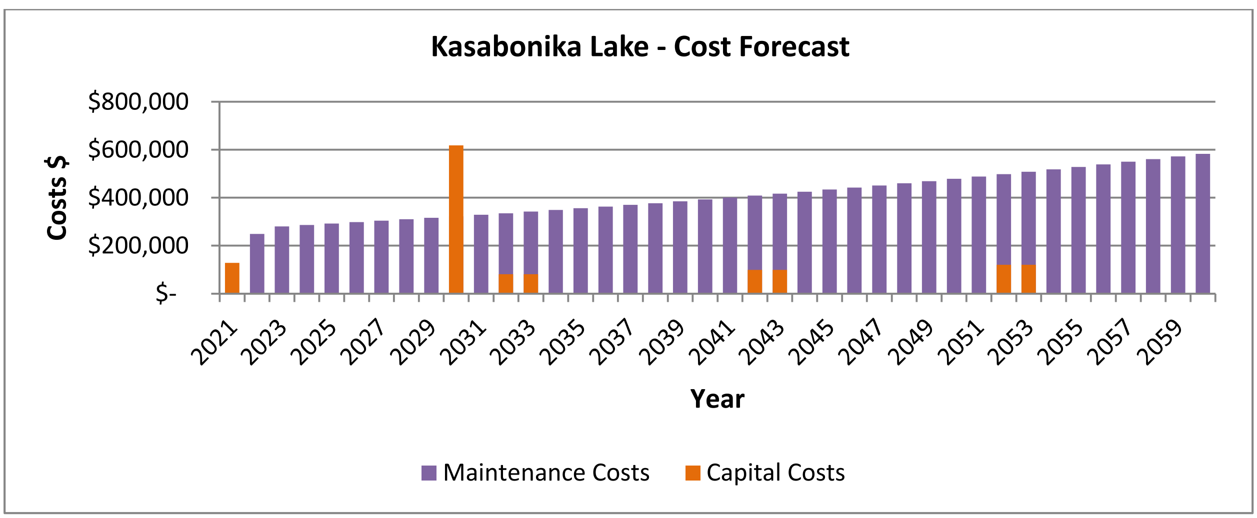
Prior To Backup Service
Convert building heating to electric, install electric block heaters, dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

Short Term Requirements
None

Potential Long Term Requirements
Upgrades to the electrical equipment prior to 2030 would increase the capability of the station for close to 20 years until the generating equipment becomes a limitation.

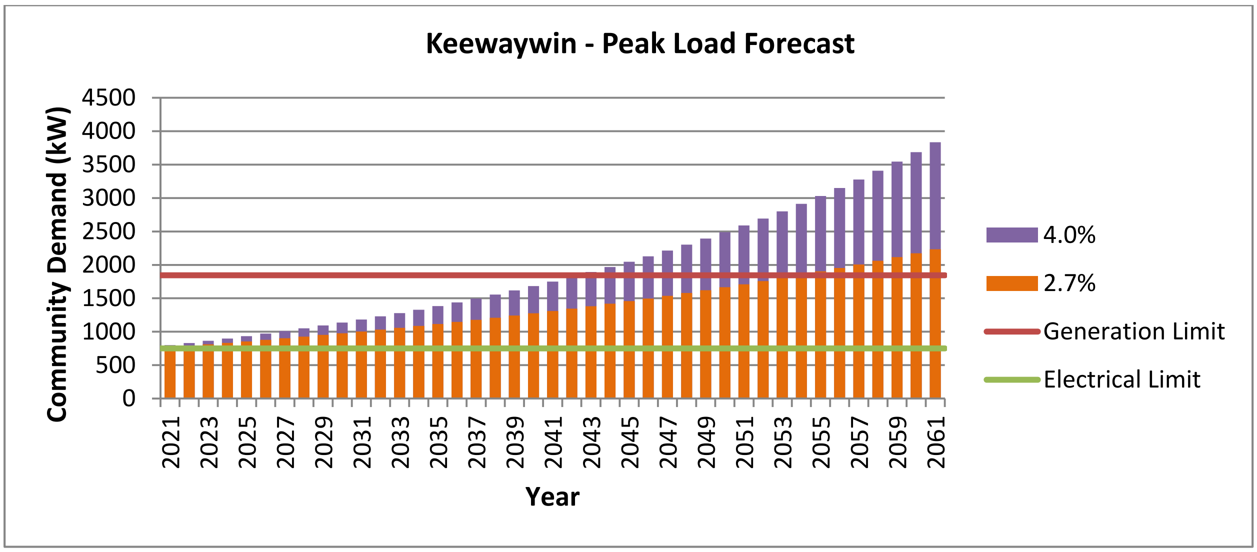
A future generation upgrade would consist of installing a 2MW containerized unit to run in parallel with the DGS. That would satisfy demand until 2061.

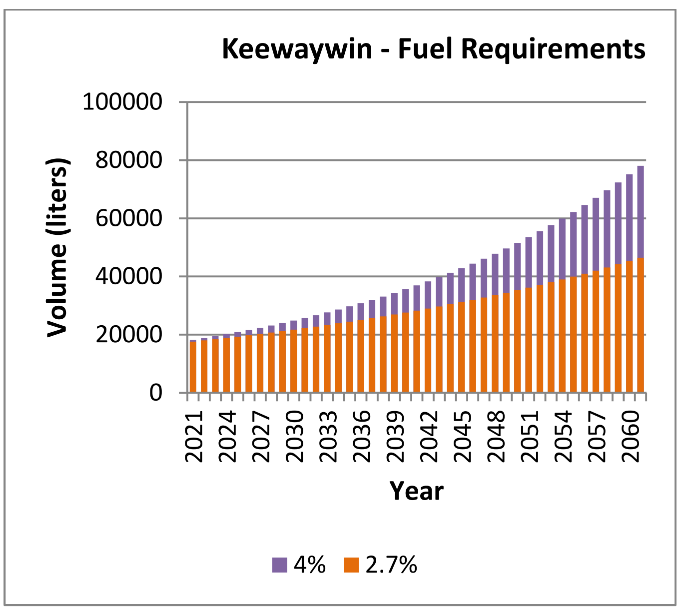
Cost Summary (2.7% growth)



Keewaywin DGS Summary

Current Configuration			
Genset Model	Cat C27	Cat C18	Cat C18
Genset Rating (kW)	725	560	560
Genset Speed (rpm)	1800	1800	1800
Genset Hours	500	6,000	5,300
Number of fuel tanks	12		
Total bulk fuel storage (L)	600,000		
2018 Peak Demand (kW)	N/A		
Generation Limit (kW)	1845		
Electrical Limit (kVA)	750		
Number of 50,000L tanks required in 2061	4		





Summary

The Keewaywin DGS is in fair condition. With a thorough cleaning and a little maintenance, the building would be suitable for backup use. The biggest concern is contamination on the site. There are many areas that look to be contaminated, particularly where oil is stored near the station and where fuel is dispensed into a truck near the bulk fuel tanks.

The gensets all have low hours at this time. However they could require major overhauls at 20,000 hours before connection to the transmission line. A few months prior to backup service, Remotes would like to do a survey of the generating assets to determine if they require any work to ensure they are reliable for backup generation. Labour costs for this inspection have been included.

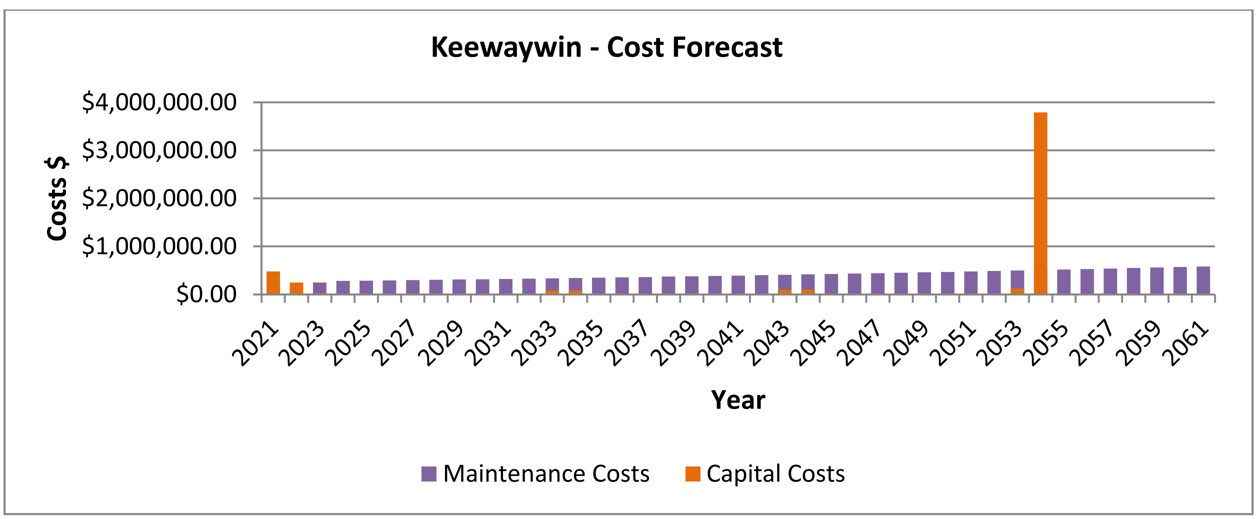
The generation portion of the station is sized to provide full backup until the mid 2040's. The electrical portion will restrict full backup capability almost immediately. In fact it appears that the station may already be running close to its electrical limit. An electrical upgrade should be considered soon, even before the transmission line arrives.

Prior To Backup Service
Dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

Short Term Requirements
Mothball eight redundant bulk tanks or remove them for use elsewhere.
If the electrical capacity is not increased prior to entering backup service, an electrical upgrade will be required immediately.

Potential Long Term Requirements
A future generation upgrade would consist of installing a 2MW containerized unit to run in parallel with the DGS. That would satisfy demand until 2061.

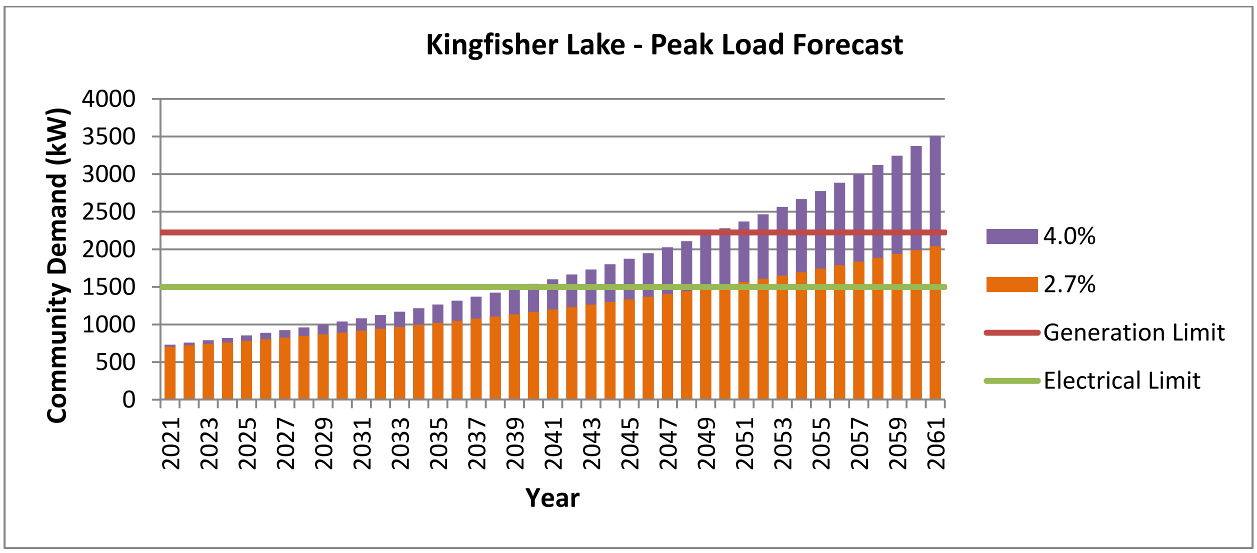
Cost Summary (2.7% growth)

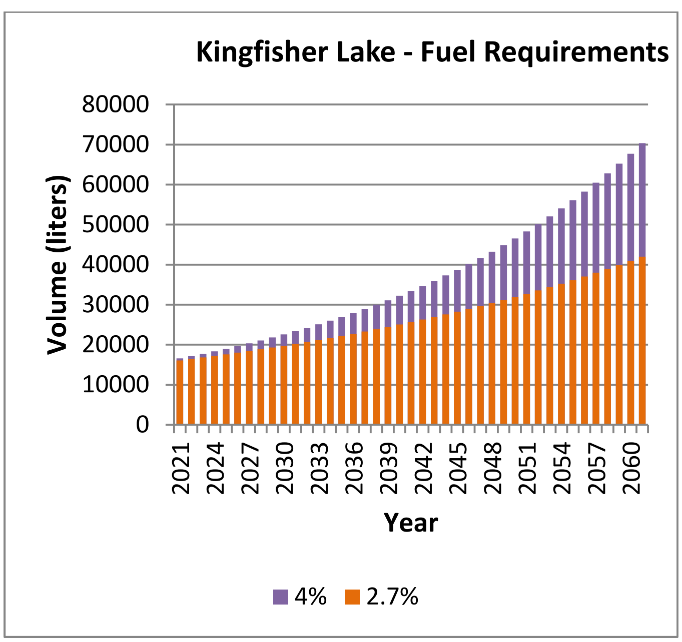


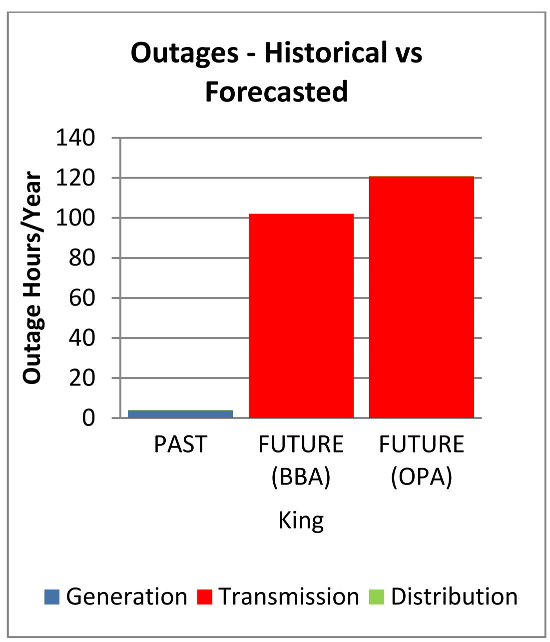
Visual Signs of Potential Contamination

Kingfisher Lake DGS Summary

Current Configuration			
Genset Model	Cat C15	Cat 3512C	Cat C27
Genset Rating (kW)	455	1045	725
Genset Speed (rpm)	1800	1200	1800
Genset Hours	41,000	400	5,500
Number of fuel tanks	7		
Total bulk fuel storage (L)	387,000		
2018 Peak Demand (kW)	650		
Generation Limit (kW)	2225		
Electrical Limit (kVA)	1500		
Number of existing tanks required in 2061	3		







Summary

The Kingfisher DGS is in good to excellent condition. The C15, C27, and the control room are in the oldest part of the station but it is still in good shape. The 3512 is in a modern part of the building. The overall duration of generation outages is very low. Two gensets were replaced in 2017 so will have lots of life left when the transmission line arrives. The C15 is forecast for replacement in 2024. Replacement is unlikely if it is only going to serve as backup. The existing genset would undergo proper maintenance to continue operating as a backup.

The station is well sized for long term backup. The generation portion of the station can provide full backup until the mid 2050's. The electrical portion is adequate until at least the early 2040's. The initial investment required to convert to backup is minimal.

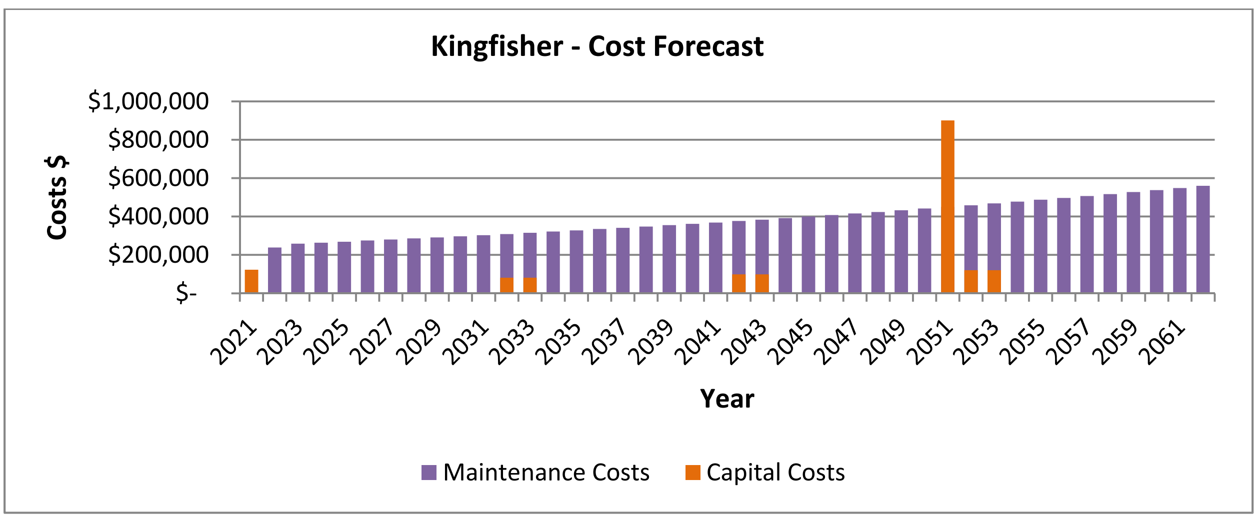
Three of the existing vertical tanks and the transfer tank are required for backup. The three remaining vertical tanks would be mothballed. They are not suitable for use elsewhere.

Prior To Backup Service
Convert building heating to electric, install electric block heaters, dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

Short Term Requirements
Mothball three redundant bulk tanks.

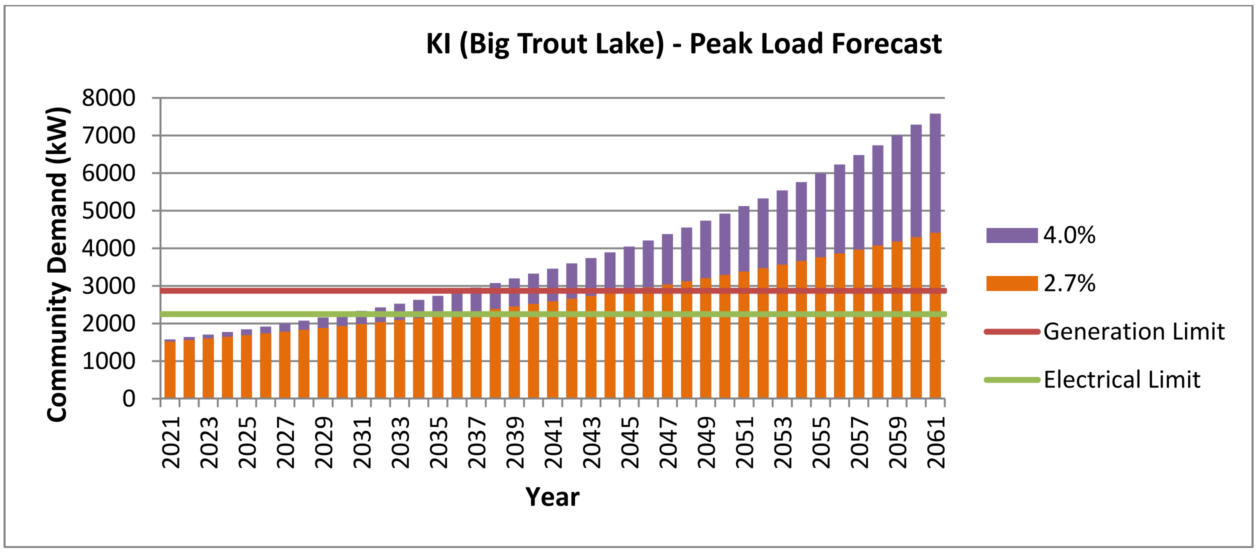
Potential Long Term Requirements
Upgrades to the electrical equipment sometime after 2040 would increase the capability of the station until at least the 2050's when generating equipment could become a limitation. Depending on growth, it's possible that a generation upgrade may not be required, but a cost is included to install a 2MW containerized unit to be run in parallel with the DGS.

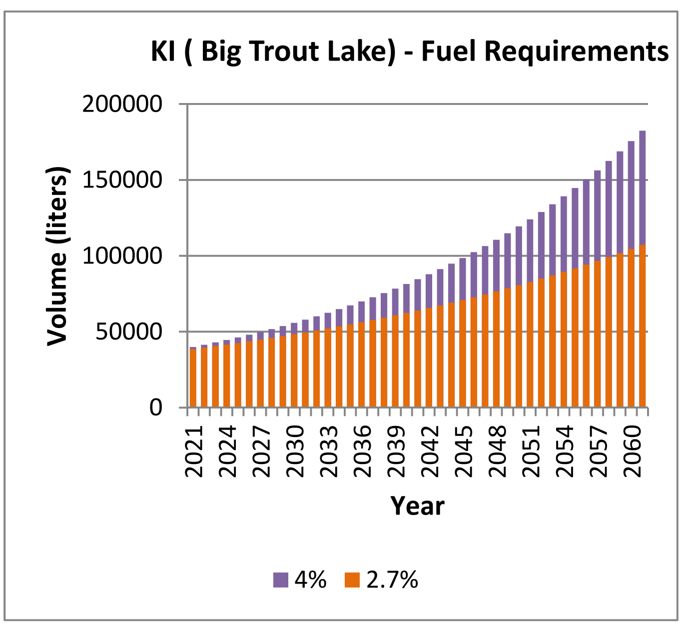
Cost Summary (2.7% growth)

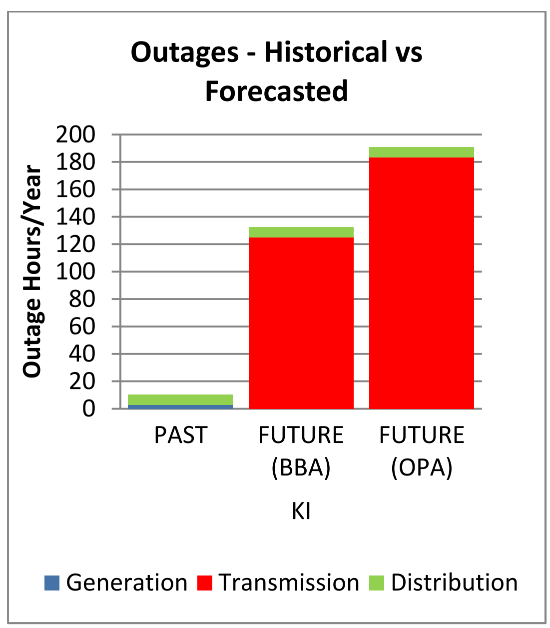


Kitchenuhmaykoosib Inninuwug (Big Trout Lake) DGS Summary

Current Configuration			
Genset Model	Cat 3412	Cat 3512	Cat 3516
Genset Rating (kW)	635	1135	1100
Genset Speed (rpm)	1800	1800	1200
Genset Hours	53,000	48,000	51,000
Number of fuel tanks	3		
Total bulk fuel storage (L)	150,000		
2018 Peak Demand (kW)	1404		
Generation Limit (kW)	2870		
Electrical Limit (kVA)	2250		
Number of existing tanks required in 2061	8		







Summary

The Big Trout Lake DGS is in fair to good condition. The 3412, 3512, and the control room are in the oldest part of the station but it is still in good shape. The 3516 is in a more modern part of the building. The overall duration of generation outages is very low. Two gensets (3412 and 3512) are scheduled for replacement in 2020 so will have lots of life left when the transmission line arrives. The 3516 is a 1200rpm unit so has plenty of life remaining.

The generation portion of the station can provide full backup until close to 2040. The electrical portion is adequate until around 2030. The initial investment required to convert to backup is minimal.

All three bulk fuel tanks are required for storage. Although they fall well short of the eight tanks required in 2061, they will provide sufficient fuel storage until about 2035.

Prior To Backup Service

Convert building heating to electric, install electric block heaters, dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

Short Term Requirements

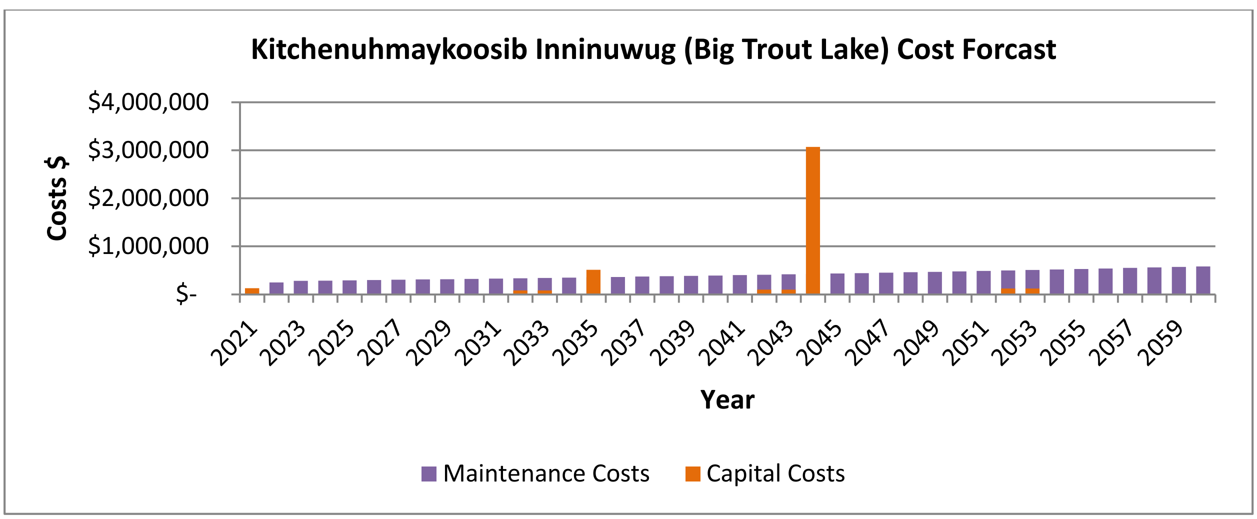
None

Potential Long Term Requirements

Upgrades to the electrical equipment around 2030 would increase the capability of the station until the generating equipment becomes a limitation.

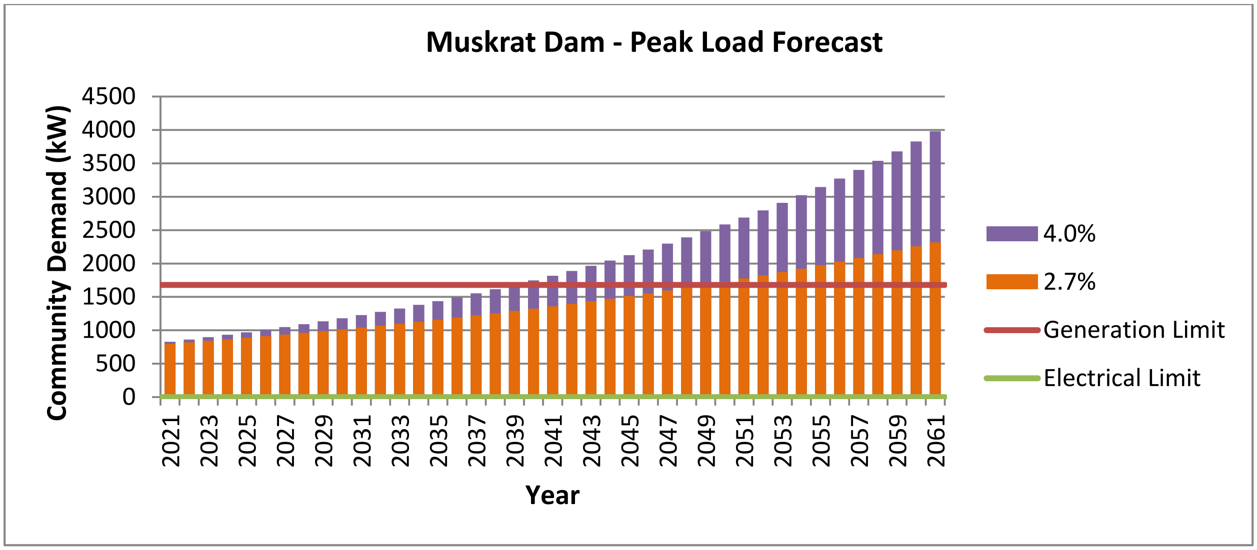
A future generation upgrade would consist of installing a 2MW containerized unit to run in parallel with the DGS. That would satisfy demand until the mid 2050's and possibly to 2061 depending on load growth.

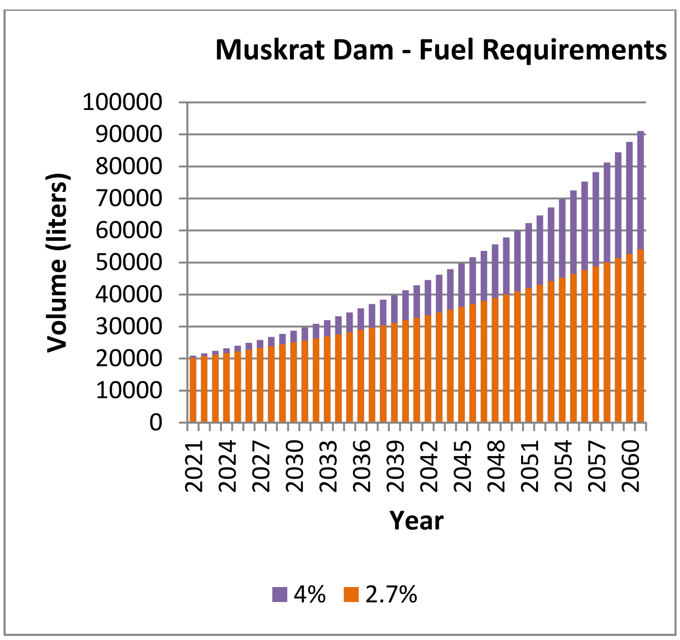
Cost Summary (2.7% growth)



Muskrat Dam DGS Summary

Current Configuration (engine hours from Nov/17)			
Genset Model	Kohler	Cat C18	Cat C27
Genset Rating (kW)	410	545	725
Genset Speed (rpm)	1800	1800	1800
Genset Hours	N/A	13,000	18,500
Number of fuel tanks	14		
Total bulk fuel storage (L)	775,000		
2018 Peak Demand (kW)	N/A		
Generation Limit (kW)	1680		
Electrical Limit (kVA)	N/A		
Number of existing tanks required in 2061	4		





Summary

The Muskrat Dam DGS was in poor condition during Remotes' visit in late 2017. It is in need of a very good cleaning. It also needs a lot of repairs to seal up holes in the walls and fix equipment that is no longer working. It is useful as a backup station but does require some work before then.

The two Cat gensets are useful for backup as long as they are properly maintained prior to then. They will both require major overhauls in the next year or two. If those are completed and other manufacturers recommended maintenance is closely followed, they have enough life to last until 2061. A few months prior to backup service, Remotes would like to do a survey of the generating assets to determine if they require any work to ensure they are reliable for backup generation. Labour costs for this inspection have been included.

The ground was mostly snow covered during the visit so contamination could not be verified. The site was apparently cleaned just a few years ago when the new tank farm was installed. Still there would have to be an assessment of any contamination prior to Remotes taking responsibility for the station.

The generation portion of the station is sized to provide full backup until about 2040. The electrical capacity is not known at this time but will likely require an upgrade within the first few years based on the electrical capacities of the other IPA stations. An electrical upgrade cost has been included a couple of years after the station begins backup operation.

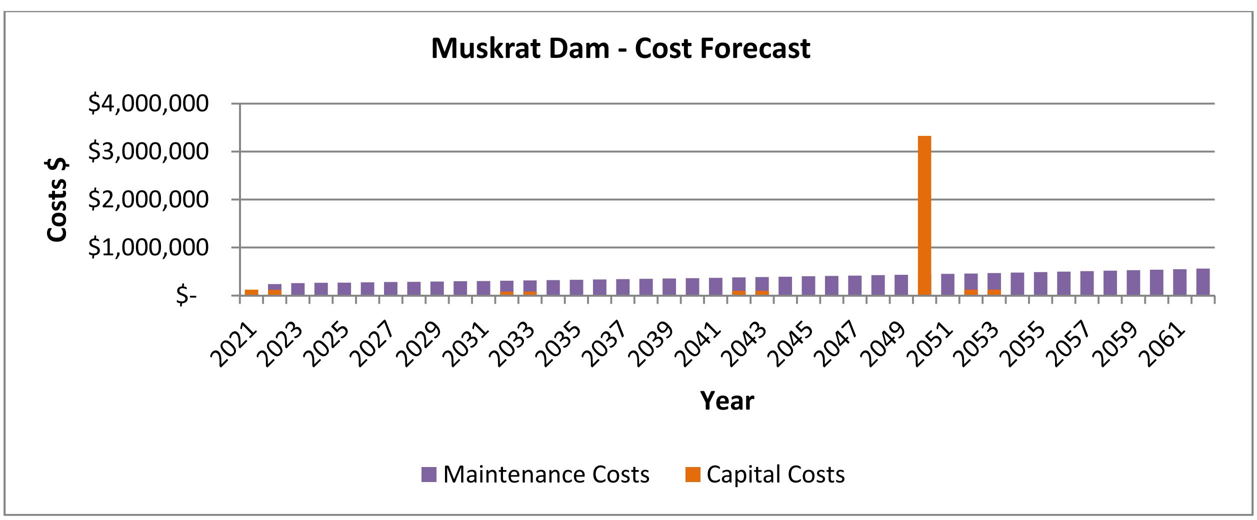
Prior To Backup Service
Dispose of excess fuel, install communications, install fencing and secure yard, install electrical connection for station service, investigate and install modifications to programming.

Short Term Requirements
Mothball ten redundant bulk tanks or remove them for use elsewhere.

Potential Long Term Requirements
An upgrade to the electrical equipment will increase the capability of the station to about 2040 when generation becomes a limitation.

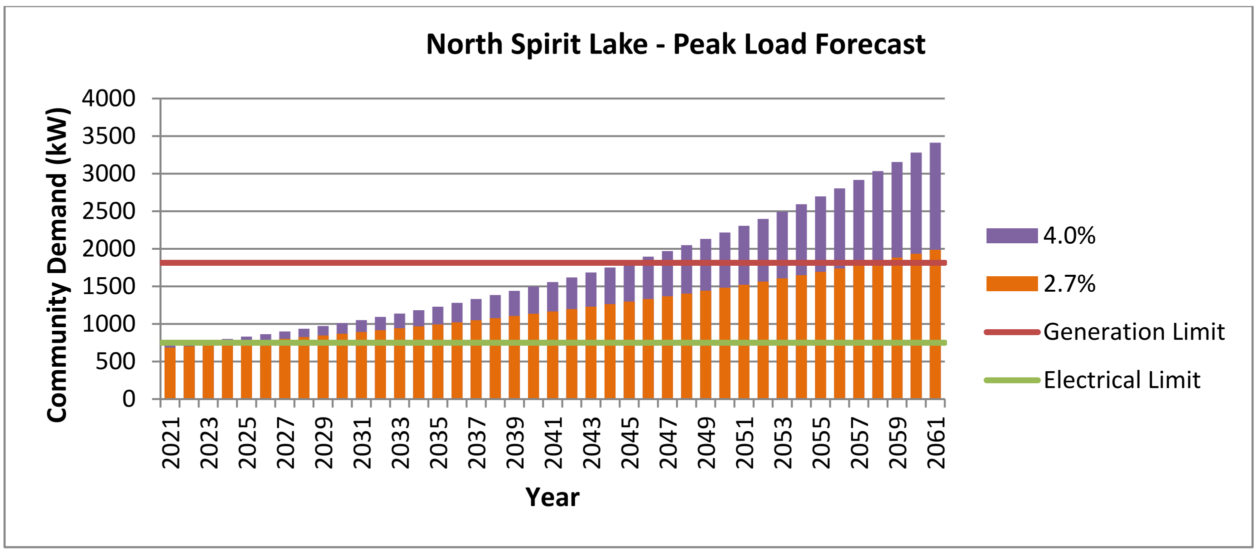
A future generation upgrade would consist of installing a 2MW containerized unit to run in parallel with the DGS. That would satisfy demand until 2061.

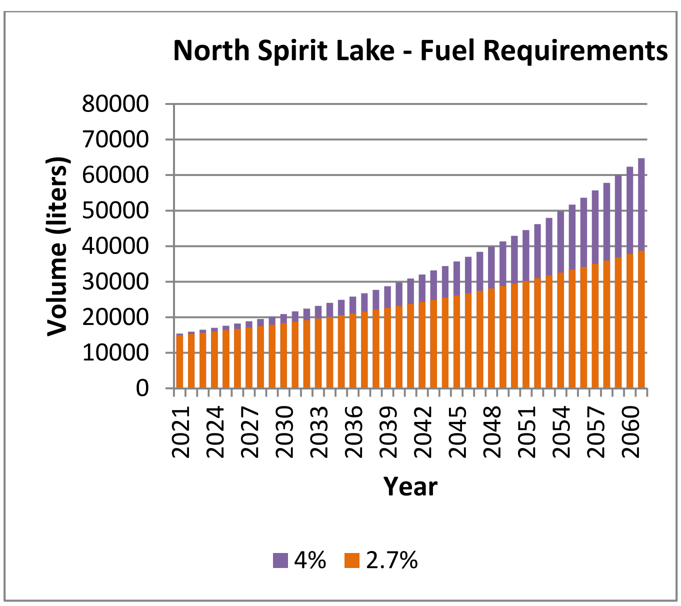
Cost Summary (2.7% growth)



North Spirit Lake DGS Summary

Current Configuration			
Genset Model	Cat C27	Cat C18	Cat C18
Genset Rating (kW)	725	545	545
Genset Speed (rpm)	1800	1800	1800
Genset Hours	5,300	7,600	8,800
Number of fuel tanks	12		
Total bulk fuel storage (L)	600,000		
2018 Peak Demand (kW)	N/A		
Generation Limit (kW)	1815		
Electrical Limit (kVA)	750		
Number of existing tanks required in 2061	3		





Summary

The North Spirit Lake DGS is in good condition. It is just in need of a good cleaning.

The gensets are all useful for backup as long as they are properly maintained prior to then. They may require major overhauls prior to connection to the transmission line. If all recommended maintenance is completed they have enough life to last until 2061. A few months prior to backup service, Remotes would like to do a survey of the generating assets to determine if they require any work to ensure they are reliable for backup generation. Labour costs for this inspection have been included.

The generation portion of the station is sized to provide full backup until the late 2040's. The electrical portion will restrict full backup capability almost immediately. In fact it appears that the station may already be running close to its electrical limit. An electrical upgrade should be considered soon, even before the transmission line arrives.

The yard does not have perimeter fencing. Some was started but not yet completed.

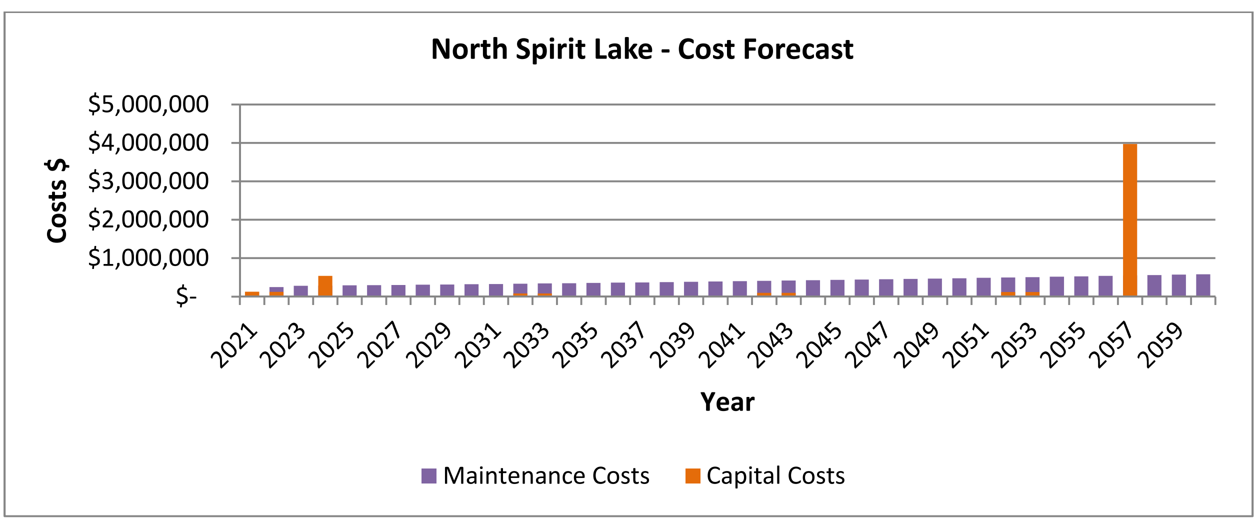
There was some staining on the ground near the bulk tanks that could be a sign of contamination (see attached pictures). It looks like it's very light but would require assessment.

Prior To Backup Service
Dispose of excess fuel, install communications, install fencing and secure yard, install electrical connection for station service, investigate and install modifications to programming.

Short Term Requirements
Mothball nine redundant bulk tanks or remove them for use elsewhere.
If the electrical capacity is not increased prior to entering backup service, an electrical upgrade will be required immediately.

Potential Long Term Requirements
A future generation upgrade would consist of installing a 2MW containerized unit to run in parallel with the DGS. That would satisfy demand well beyond 2061.

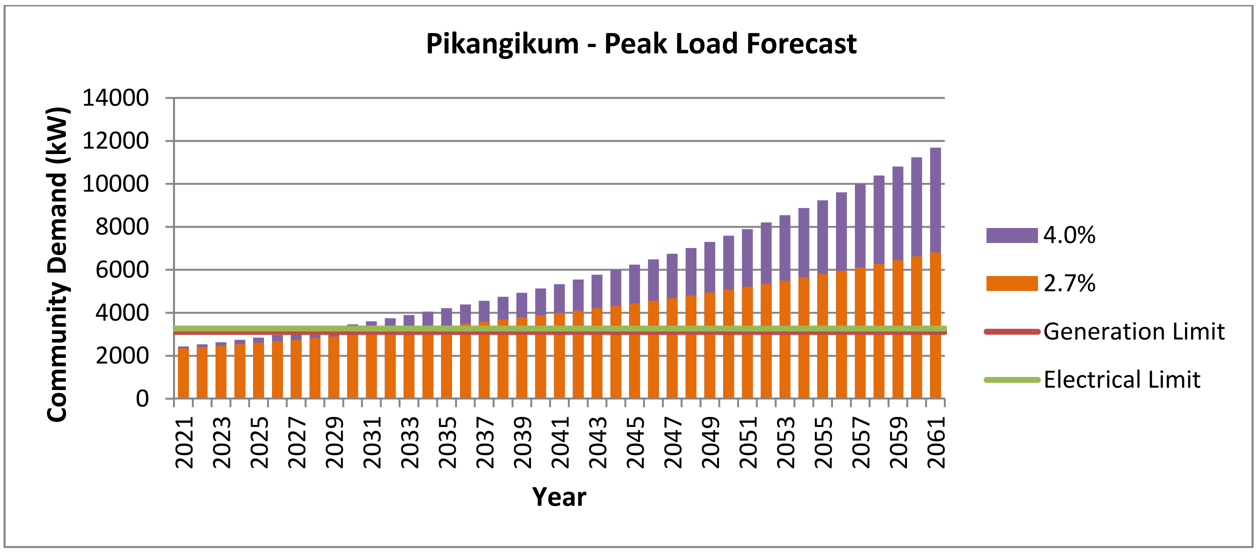
Cost Summary (2.7% growth)

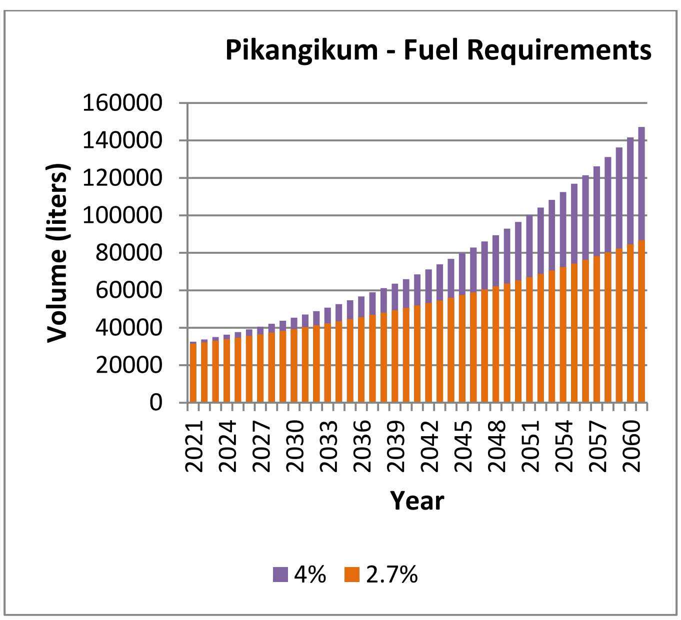


Visual Signs of Potential Contamination

Pikangikum Summary

Proposed Configuration			
Genset Model	Kohler Container	Kohler Container	2MW Container
Genset Rating (kW)	555	555	2000
Genset Speed (rpm)	1800	1800	1800
Genset Hours	0	0	0
Number of fuel tanks	3		
Total bulk fuel storage (L)	150,000		
2018 Peak Demand (kW)	N/A		
Generation Limit (kW)	3110		
Electrical Limit (kVA)	3110		
Number of existing tanks required in 2061	10		





Summary

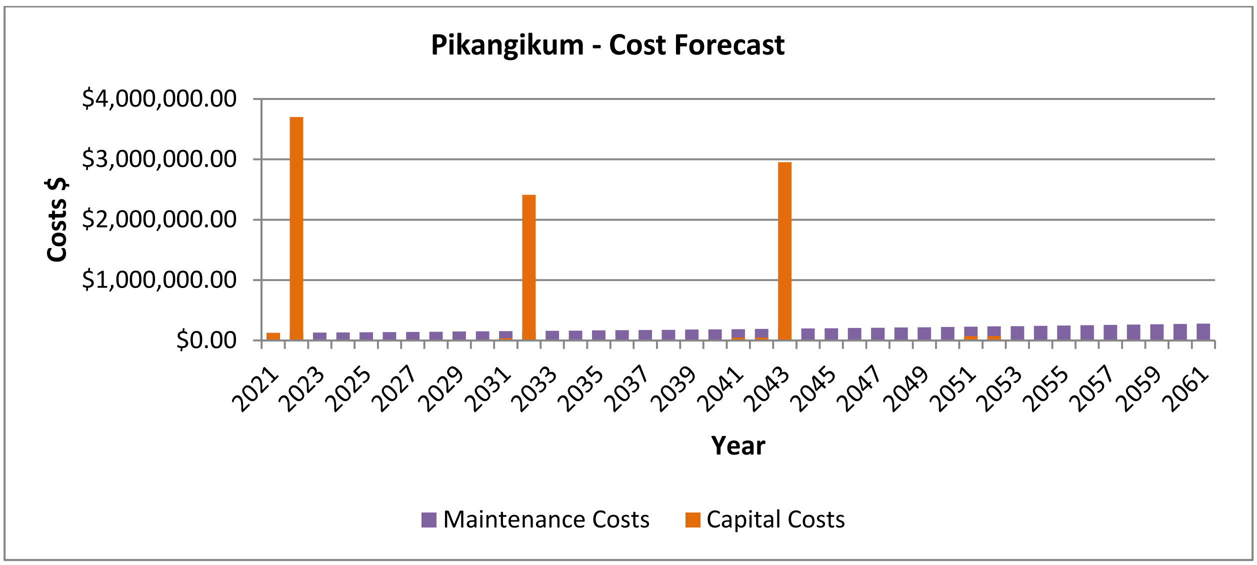
The current DGS is being removed as part of the transmission connection project. The DGS was not suitable for backup power. There are two 555kW containerized units at the community school that will be available for backup. Apparently the school connection to the distribution system was not sized to handle the complete community demand.

Further discussion and analysis to develop a backup solution that works for the community need to take place. For the purposes of costing in this report, the proposal is to use the two existing 555kW units in conjunction with a new 2MW containerized genset at an appropriate site in the community. This combination will provide full backup power until about 2030. Three bulk fuel tanks will be required as well. They will provide sufficient storage until the community demand exceeds the generation capacity.

Potential Long Term Requirements

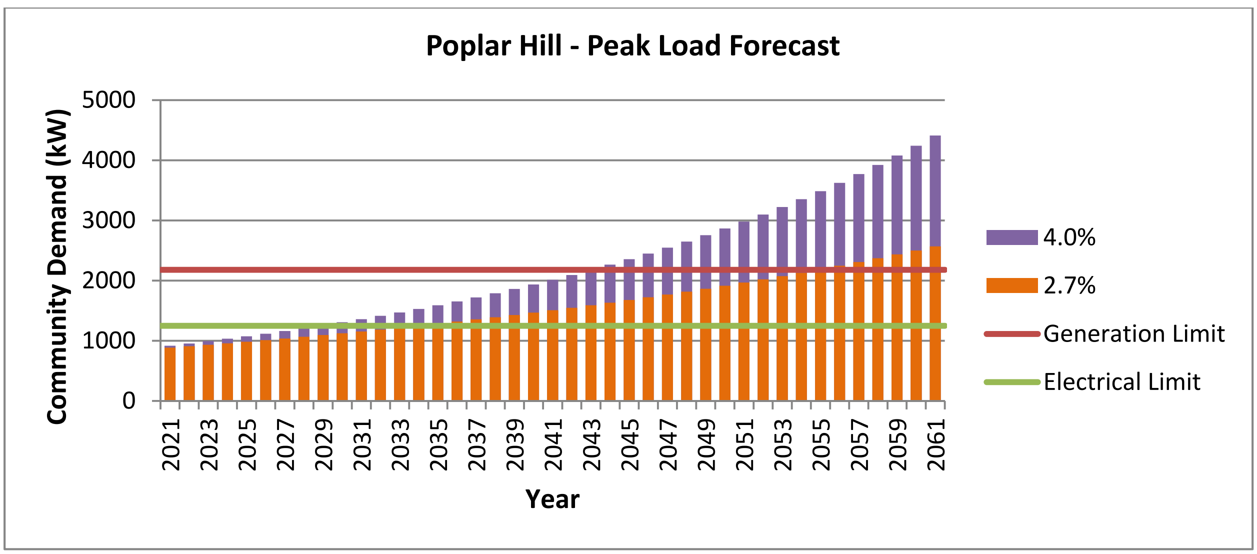
A new site should leave adequate room for a future 2MW unit and additional bulk tanks if a future upgrade is desired. Future upgrades would consist of a second 2MW unit around 2030 and a third 2MW unit around 2040.

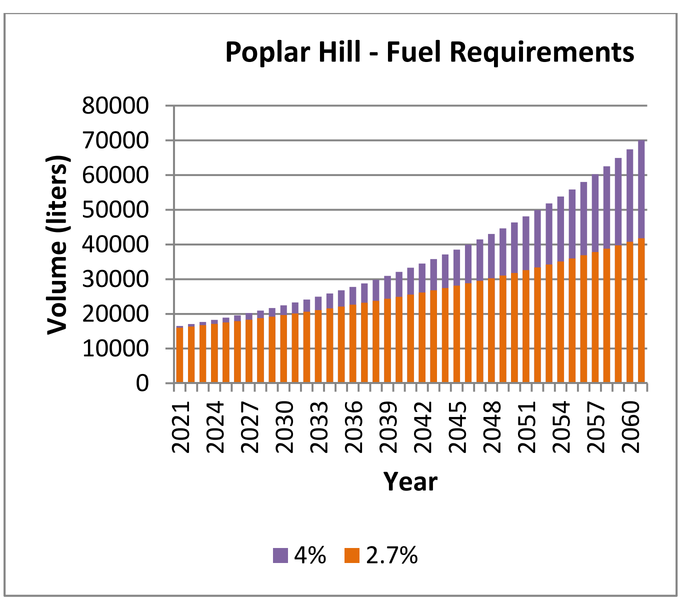
Cost Summary (2.7% growth)



Poplar Hill DGS Summary

Planned Configuration			
Genset Model	Cat C27	Cat C18	Cat C32
Genset Rating (kW)	725	545	910
Genset Speed (rpm)	1800	1800	1800
Genset Hours	4,800	0	0
Number of fuel tanks	12		
Total bulk fuel storage (L)	600,000		
2018 Peak Demand (kW)	N/A		
Generation Limit (kW)	2180		
Electrical Limit (kVA)	1250		
Number of existing tanks required in 2061	4		





Summary

The Poplar hill DGS was destroyed in a fire last winter. The community is currently being powered by one C27 containerized unit. Two other gensets are on site but have not been installed yet. There is a plan to install the C32 in a small garage on the site and bring in a metal building this winter for erection next year. It will house the C18 and C32. The station may end up being manually controlled without switchgear but that has not been determined yet.

The gensets will all be useful for backup as long as they are properly maintained prior to then. If all recommended maintenance is completed they have enough life to last until 2061. A few months prior to backup service, Remotes would like to do a survey of the generating assets to determine if they require any work to ensure they are reliable for backup generation. Labour costs for this inspection have been included.

The generation portion of the station is sized to provide full backup until about 2045. The existing transformers will restrict full backup capability around 2030.

No signs of contamination were noticed. There is obviously some around the station due to the fire, but it is assumed that would be cleaned when the station is removed.

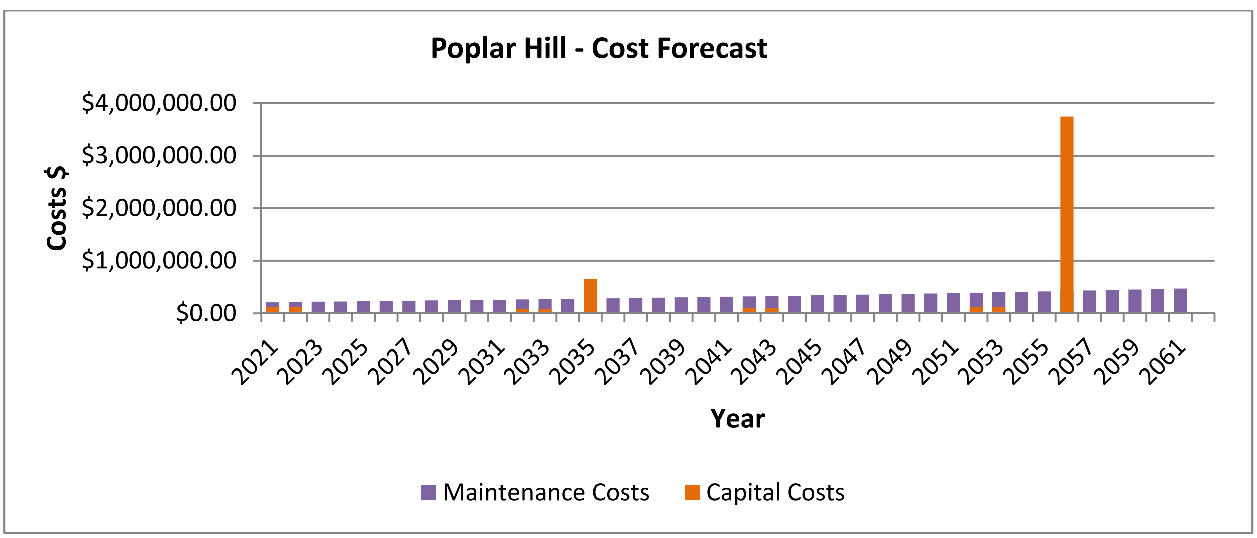
Prior To Backup Service
Dispose of excess fuel, install communications, install fencing and secure yard, install electrical connection for station service, investigate and install modifications to programming.

Short Term Requirements
Mothball eight redundant bulk tanks or remove them for use elsewhere.

Potential Long Term Requirements
An upgrade to the electrical equipment will increase the capability of the station to about 2045 when generation becomes a limitation.

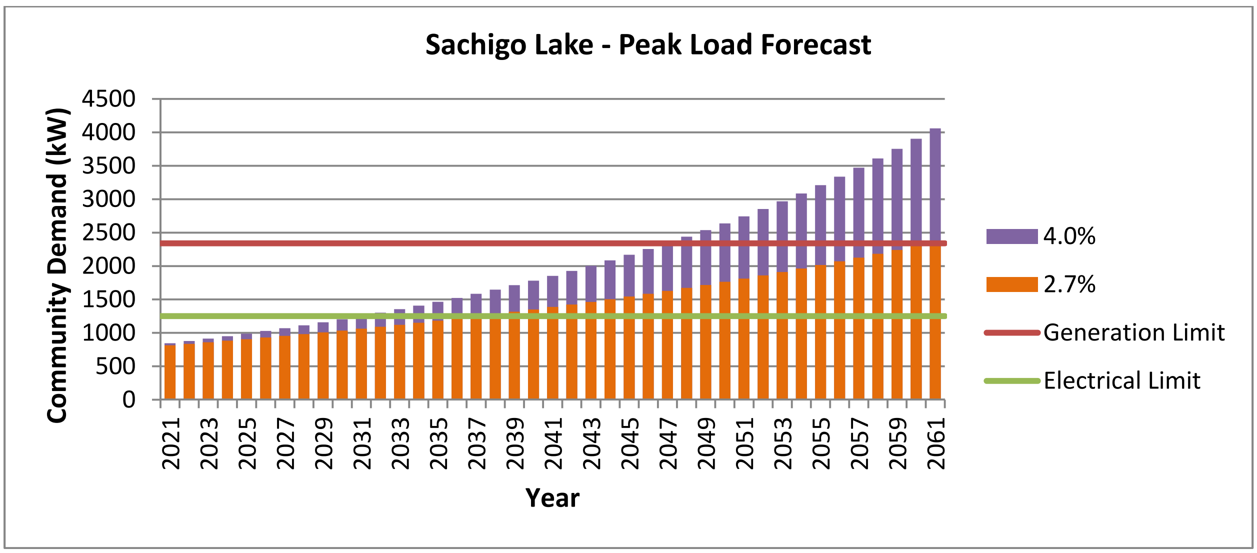
A future generation upgrade would consist of installing a 2MW containerized unit to run in parallel with the DGS. That would satisfy demand until 2061.

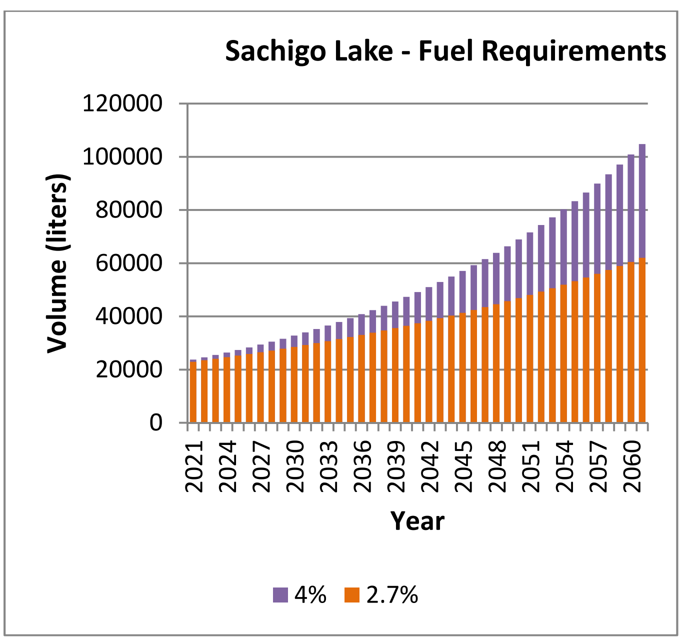
Cost Summary (2.7% growth)

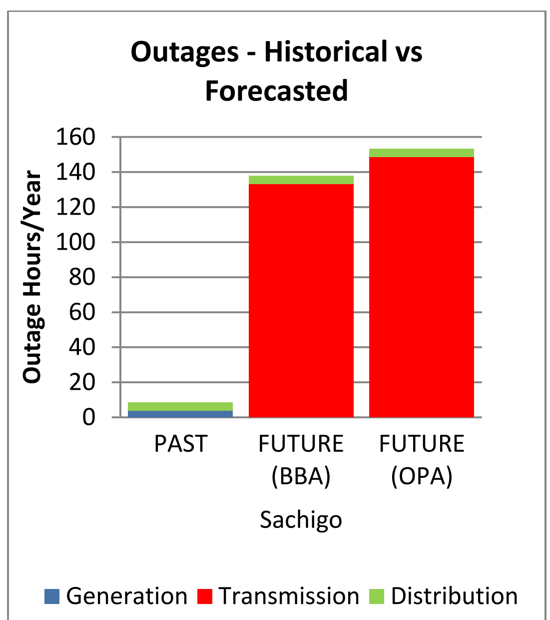


Sachigo Lake DGS Summary

Current Configuration			
Genset Model	Cat C27	Cat C15	Cat 3516
Genset Rating (kW)	635	455	1250
Genset Speed (rpm)	1800	1800	1200
Genset Hours	17,000	29,000	29,000
Number of fuel tanks	5		
Total bulk fuel storage (L)	250,000		
2018 Peak Demand (kW)	752		
Generation Limit (kW)	2340		
Electrical Limit (kVA)	1250		
Number of existing tanks required in 2061	5		







Summary

The Sachigo Lake DGS is in excellent condition. The overall duration of generation outages is very low. All of the gensets will have sufficient life remaining to serve in a backup capacity.

The generation portion of the station can provide full backup until close to 2050. The electrical portion is adequate until just after 2030. The investment required to convert to backup is minimal.

All five bulk fuel tanks are required for storage.

Prior To Backup Service

Convert building heating to electric, install electric block heaters, dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

Short Term Requirements

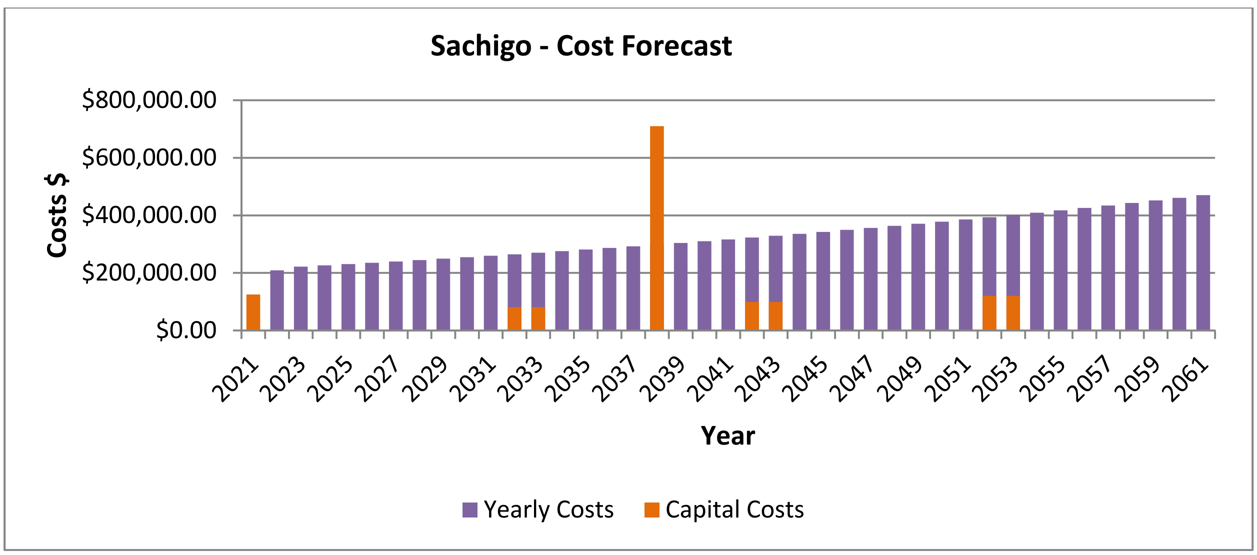
None

Potential Long Term Requirements

Upgrades to the electrical equipment just after 2030 would increase the capability of the station for almost 20 years until the generating equipment becomes a limitation.

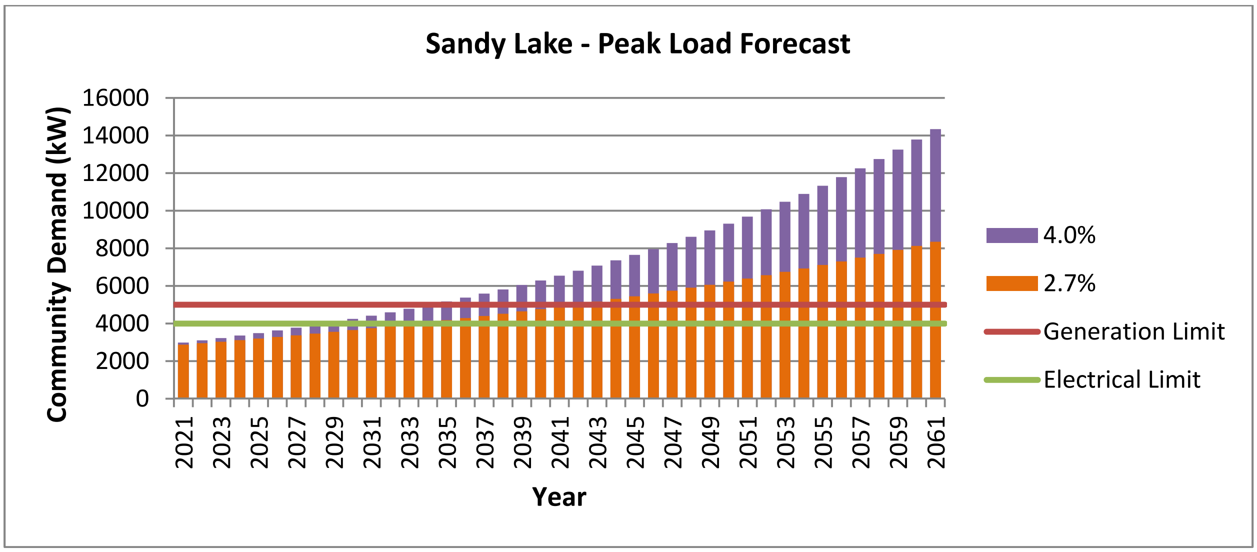
A future generation upgrade may not be required depending on load growth. If it is required, it would consist of installing a 2MW containerized unit to run in parallel with the DGS. That would satisfy demand beyond 2061.

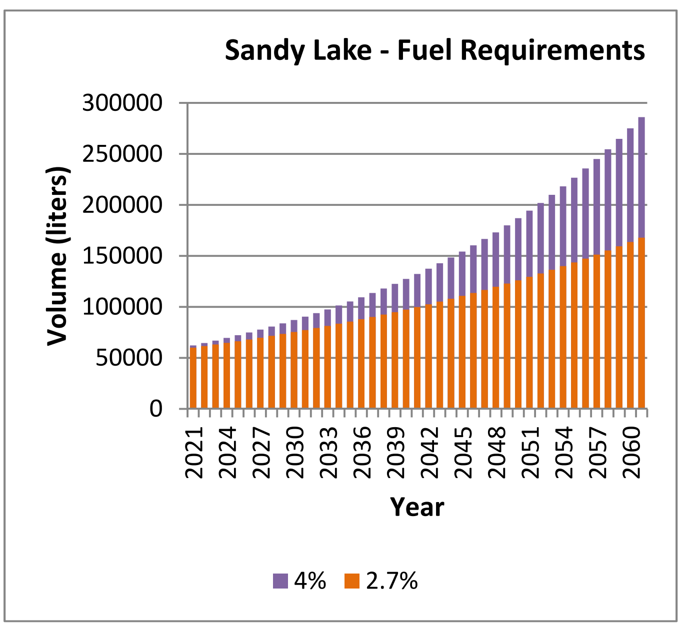
Cost Summary (2.7% growth)

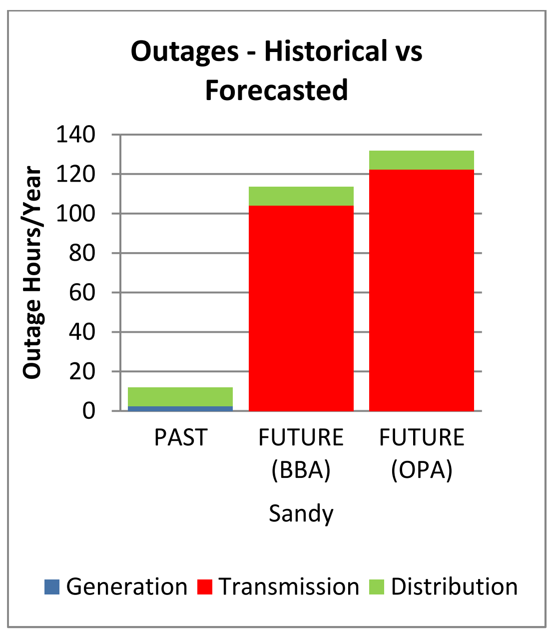


Sandy Lake DGS Summary

Current Configuration				
Genset Model	Cat 3516	Cat 3516	Cat 3516B	Cat 3512
Genset Rating (kW)	1250	1250	1500	1000
Genset Speed (rpm)	1200	1200	1200	1200
Genset Hours	51,000	28,500	10,000	56,000
Number of fuel tanks	8			
Total bulk fuel storage (L)	400,000			
2018 Peak Demand (kW)	2655			
Generation Limit (kW)	5000			
Electrical Limit (kVA)	4000			
Number of existing tanks required in 2061	14			







Summary
The Sandy Lake DGS is in excellent condition. The overall duration of generation outages is very low. All of the gensets are 1200rpm so are scheduled to last to 120,000 hours. All will have sufficient life for backup service. The 1000kW unit is scheduled for replacement in 2020 with a 1500kW unit.

The generation portion of the station can provide full backup until 2035 or beyond. Once the larger unit is installed in 2020, the generation limit will become 5500kW, meaning the generation will be suitable for full backup until closer to 2040. The electrical portion is adequate until about 2030. The investment required to convert to backup is minimal.

All eight existing bulk tanks will be required for future storage. They will store adequate fuel until about 2050.

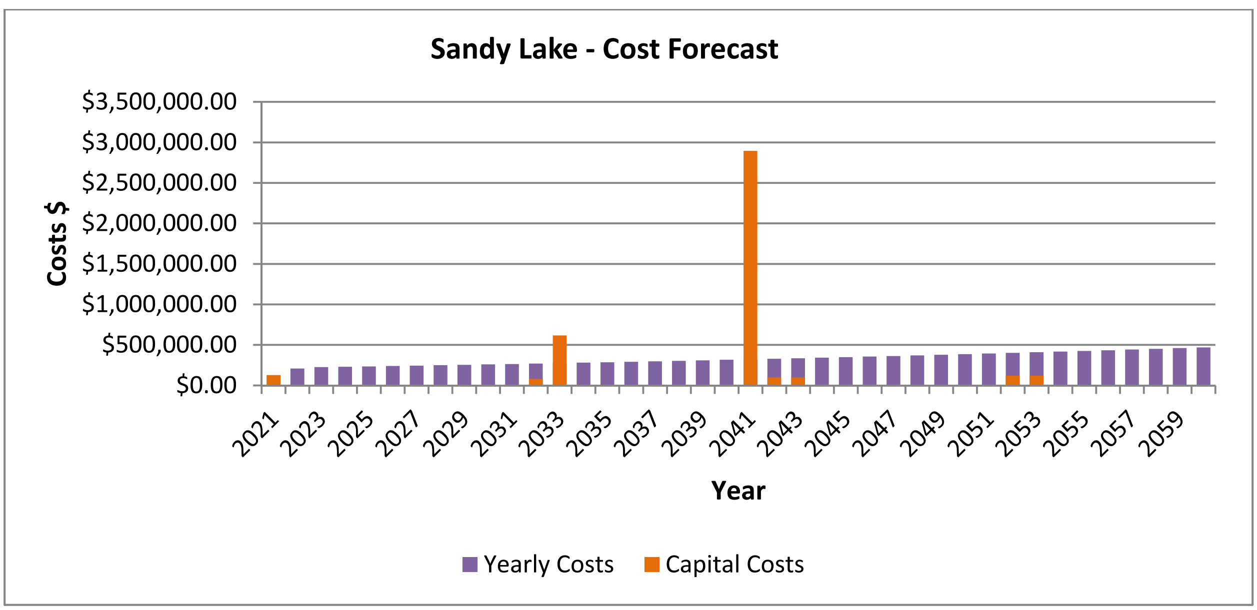
Prior To Backup Service
Convert building heating to electric, install electric block heaters, dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

Short Term Requirements
None

Potential Long Term Requirements
Upgrades to the electrical equipment around 2030 would increase the capability of the station until the generating equipment becomes a limitation.

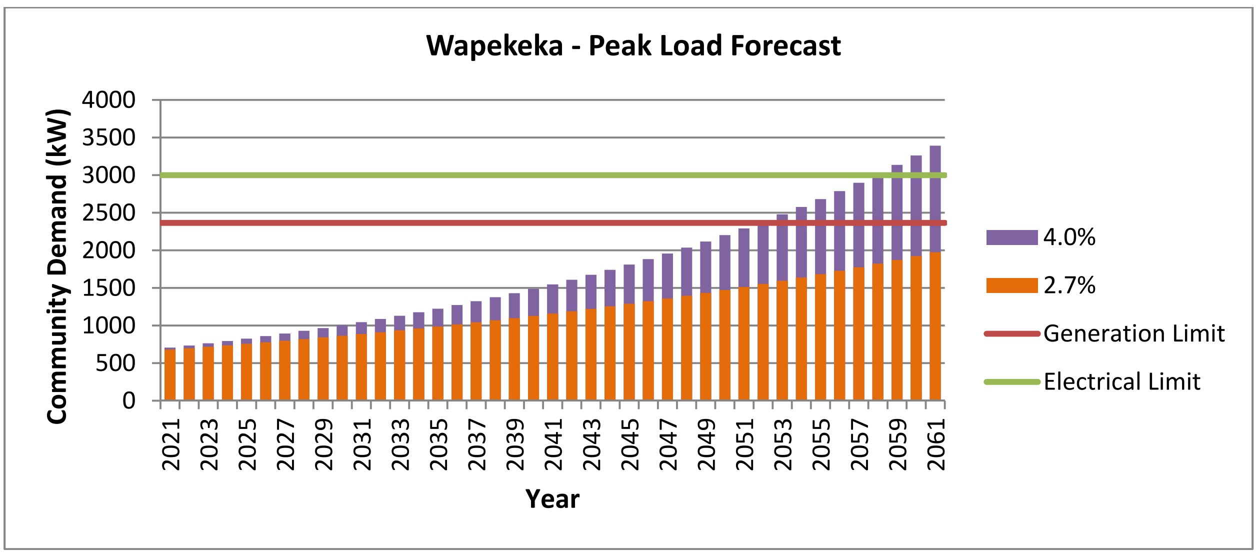
Future generation upgrades would consist of installing a 2MW containerized unit to run in parallel with the DGS in about 2035. Second 2MW upgrade would be required about 2045. That would satisfy demand until the 2050's and possibly to 2061 depending on load growth.

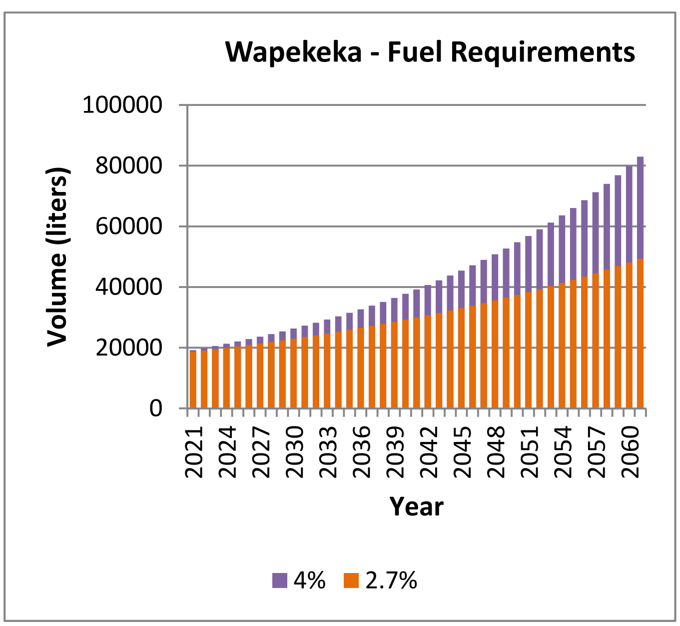
Cost Summary (2.7% growth)

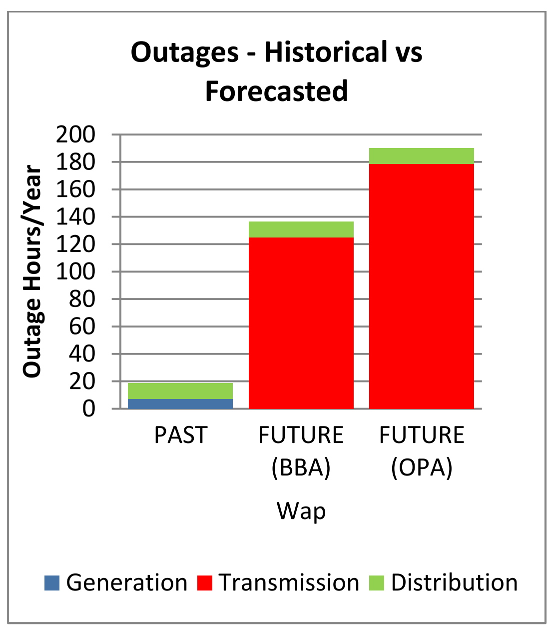


Wapekeka DGS Summary

Current Configuration (after 2019 upgrade)			
Genset Model	Cat 3508B	Cat 3512C	Cat C15
Genset Rating (kW)	910	1045	410
Genset Speed (rpm)	1800	1200	1800
Genset Hours	13,600	0	16,500
Number of fuel tanks	5		
Total bulk fuel storage (L)	250,000		
2018 Peak Demand (kW)	628		
Generation Limit (kW)	2365		
Electrical Limit (kVA)	3000		
Number of existing tanks required in 2061	4		







Summary

The Wapekeka DGS is in excellent condition. The overall duration of generation outages is low. All of the gensets will have sufficient life for backup service. A 2019 upgrade will install the 1045kW unit and upgrade the electrical limit of the station to that shown.

The generation portion of the station can provide full backup until the 2050's and possibly to 2061 depending on load growth. The electrical portion is adequate until 2061. The investment required to convert to backup is minimal.

One bulk tank will be redundant.

Prior To Backup Service

Convert building heating to electric, install electric block heaters, dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

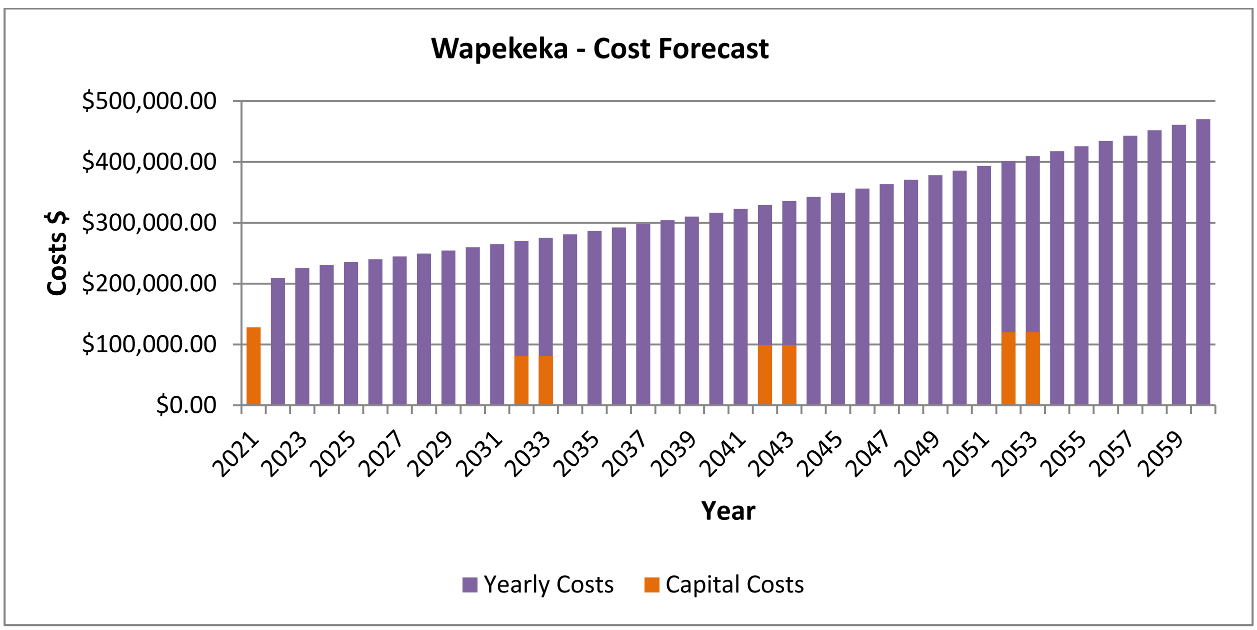
Short Term Requirements

Mothball one redundant bulk tank or remove it for use elsewhere.

Potential Long Term Requirements

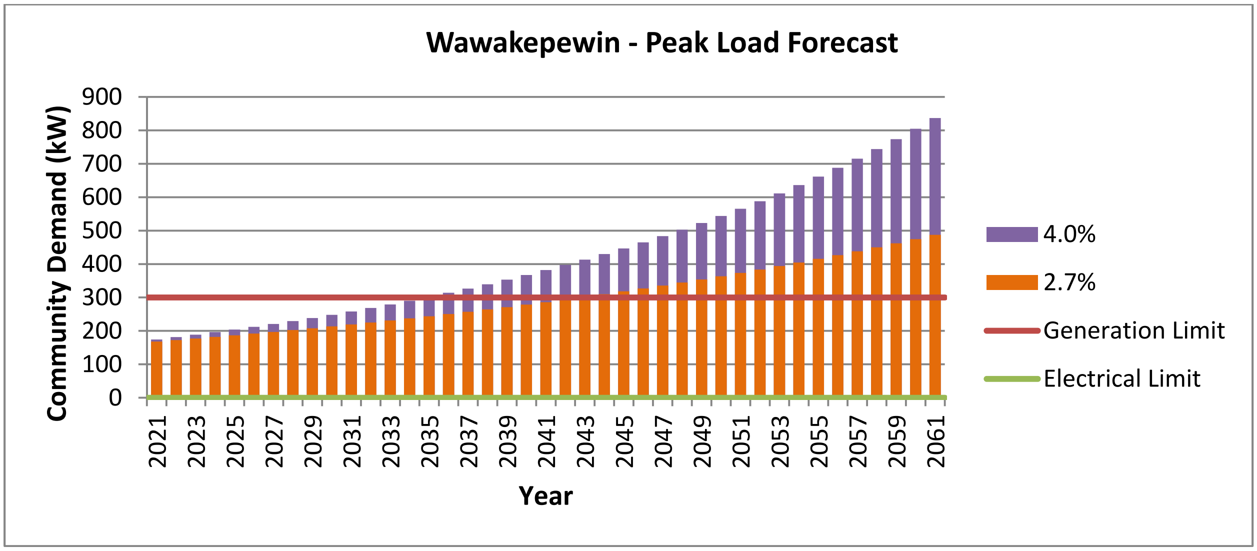
No upgrades are planned for this station. There is a good possibility that the generation is sufficient to meet peak demand in 2061. It will definitely provide full backup for other than short periods in the winter until 2061.

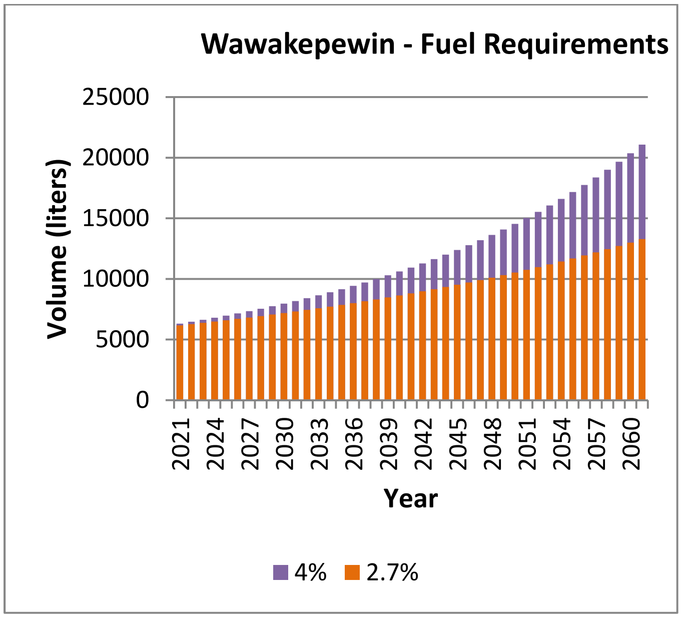
Cost Summary (2.7% growth)



Wawakapewin DGS Summary

Current Configuration (engine hours from Jan/18)			
Genset Model	John Deere	John Deere	John Deere
Genset Rating (kW)	125	125	50
Genset Speed (rpm)	1800	1800	1800
Genset Hours	14,300	23,500	7,400
Number of fuel tanks	5 or 6		
Total bulk fuel storage (L)	250,000+		
2018 Peak Demand (kW)	N/A		
Generation Limit (kW)	300		
Electrical Limit (kVA)	N/A		
Number of existing tanks required in 2061	1		





Summary

Unfortunately a site visit to directly assess the Wawakapewin DGS was not feasible in the timeframe for this report. Remotes was given an assessment that Toromont completed in early 2018, but are not aware of what work may have been done after that report was completed. Based on the report, it sounds like the gensets are in poor condition. They do not sound reliable and the 125kW units do have a fair amount of hours for this particular type of genset. Remotes have similar gensets at the Hillsport DGS and just replace them at 20,000+ hours rather than rebuild them. The condition of the building, switchgear, fuel system, or other auxiliaries is not knows, but it's fair to assume they will require some work. It is recommended to consider options to provide backup power using other means.

Since the community has very few homes, one option could be to supply each home with a small portable generator. However there are a number of issues with this solution. If a home used electric heat, a portable generator would not be able to supply it. There would be fuel stored and dispensed at each home, increasing the chance of contamination. Some generators would undoubtedly not start when required.

It is recommended to purchase and install one new 300kW containerized unit with its own switchgear. The existing station could be removed. One of the existing bulk tanks would be retained for the backup unit. A 300kW unit will provide full backup into the mid 2030's. However it may run at light loads for the first few years so could require a load bank yearly to heat it up and burn off any deposits.

If there is contamination at the existing DGS site, the new 300kW unit would need to be installed at a new site. Any contamination would be treated by others as part of the DGS decommissioning.

Prior To Backup Service

Dispose of excess fuel, install communications, install fencing and secure yard, install electrical connection for station service.

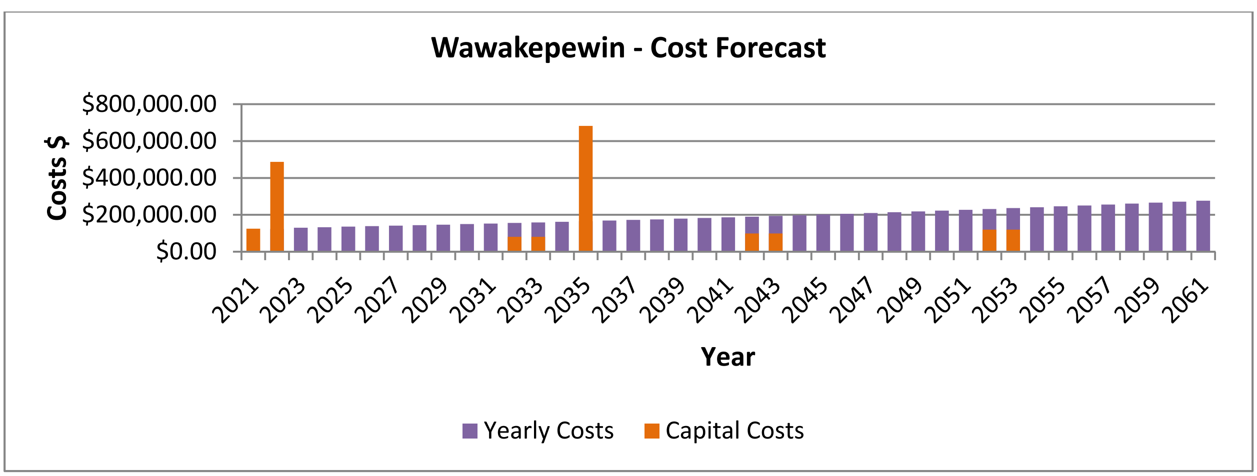
Short Term Requirements

Dismantle the existing DGS. Costs for this are not included as they should be covered elsewhere since they would be required regardless of whether backup generation is installed.

Potential Long Term Requirements

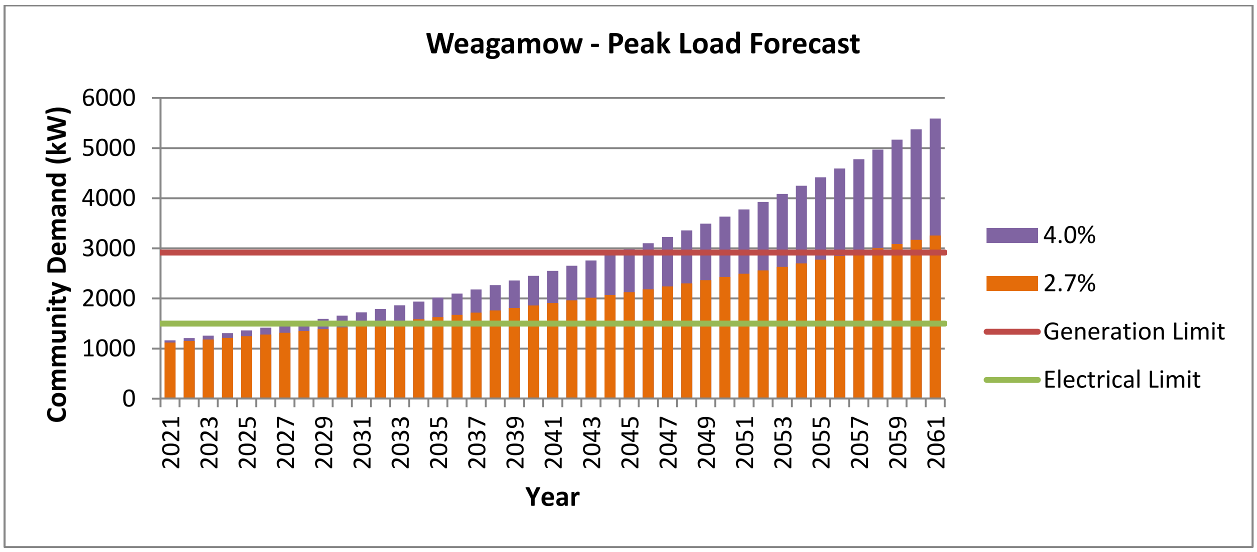
A future upgrade would consist of installing another 300kW containerized unit around 2036. That will provide enough capacity to provide backup to 2061.

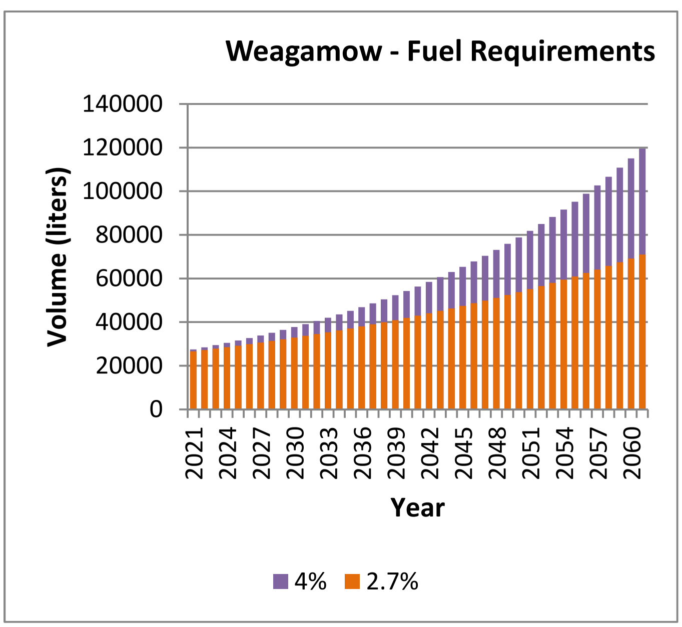
Cost Summary (2.7% growth)

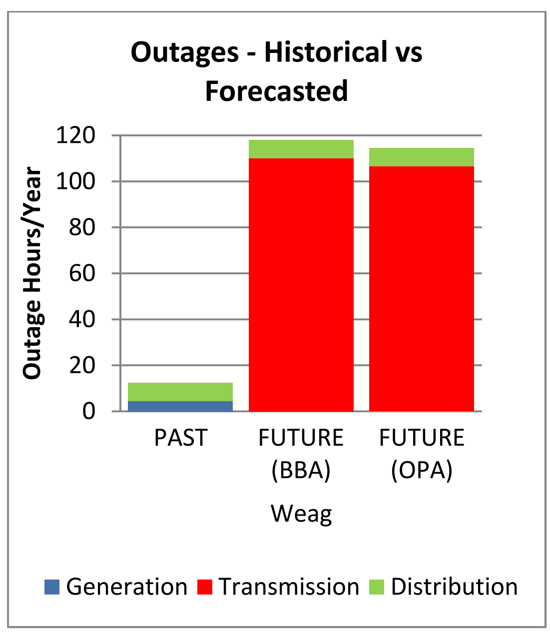


Weagamow DGS Summary

Current Configuration				
Genset Model	Cat 3412	Cat C27	Cat C15	Cat 3516
Genset Rating (kW)	635	725	455	1100
Genset Speed (rpm)	1800	1800	1800	1200
Genset Hours	86,000	8,600	19,000	N/A
Number of fuel tanks	6			
Total bulk fuel storage (L)	300,000			
2018 Peak Demand (kW)	1035			
Generation Limit (kW)	2915			
Electrical Limit (kVA)	1500			
Number of existing tanks required in 2061	6			







Summary

The Weagamow DGS is in fair condition. It is actually inadequate for prime power but is suitable for backup use.

The overall duration of generation outages is very low. The 3412 genset has a lot of hours. It remains in place because a new genset of similar output would be difficult to fit in the same location. If the station becomes a backup station, Remotes will ensure that this genset is reliable for backup use. The other two Remotes gensets will have plenty of life left. The 3516 is owned by the band. It has been assumed that it will remain for backup use. Its condition will need to be assessed prior to depending on it for backup.

The generation portion of the station can provide full backup until the mid 2040's. The electrical portion is adequate until almost 2030. The investment required to convert to backup is minimal.

All six bulk fuel tanks are required for storage.

Prior To Backup Service

Convert building heating to electric, install electric block heaters, dispose of excess fuel, install communications, repair fencing and secure yard, install electrical connection for station service, install modifications to programming.

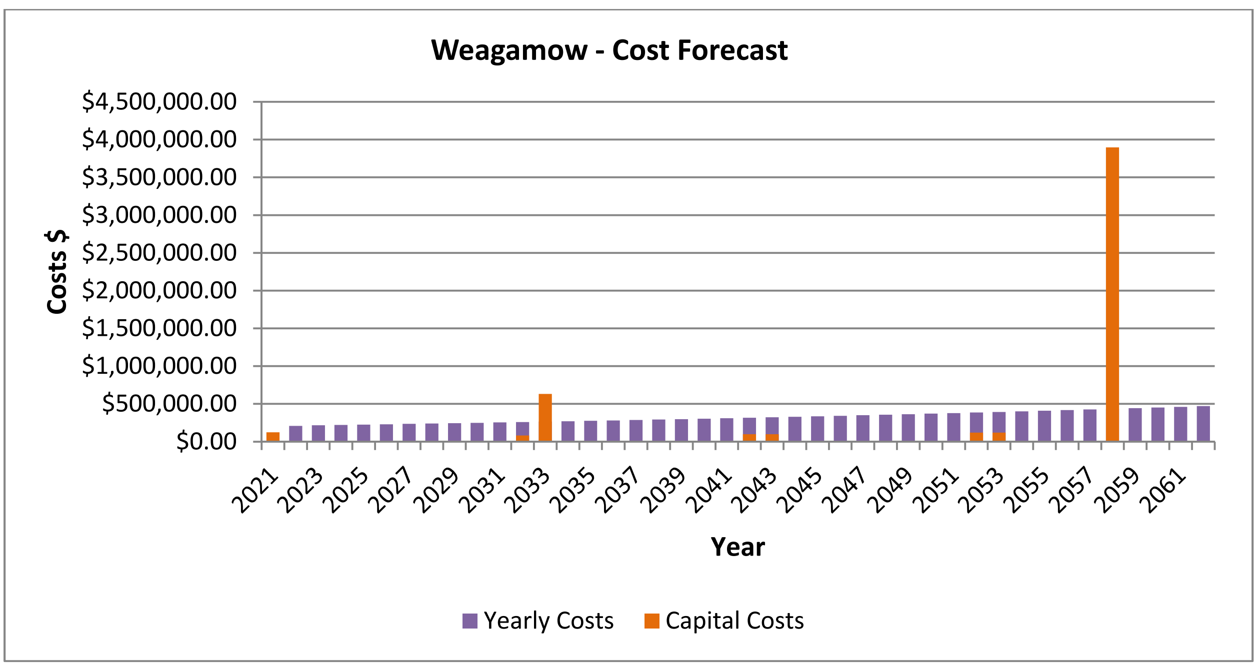
Short Term Requirements

None

Potential Long Term Requirements

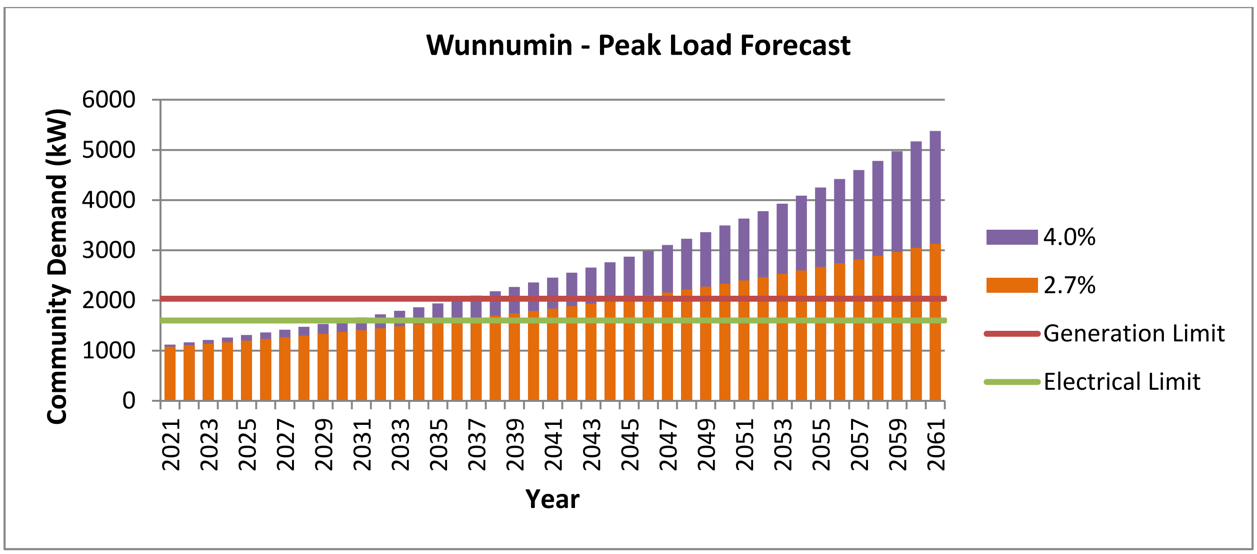
Because of the condition of the station, it is recommended that when an electrical upgrade is required just prior to 2030, the station be scrapped completely. A 2MW containerized unit would be installed and would provide sufficient capacity until about 2036. At that point a second 2MW unit would be installed. It would increase capacity enough to provide backup generation until 2061.

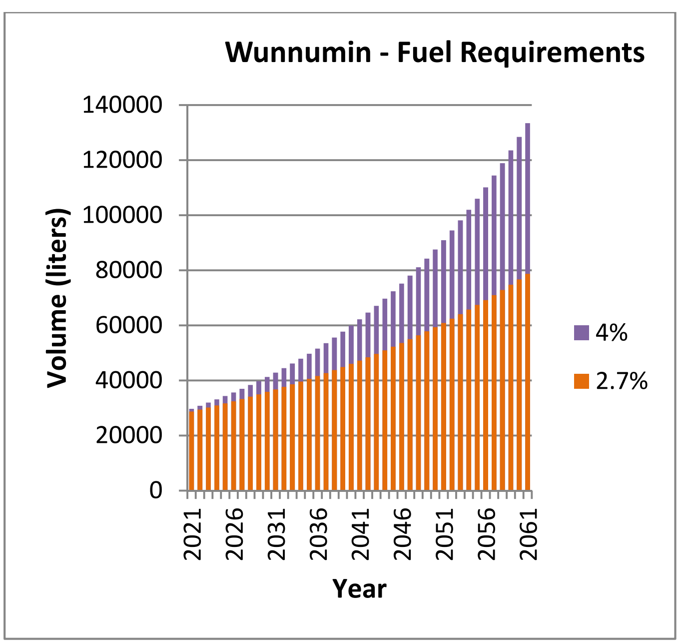
Cost Summary (2.7% growth)



Wunnumin Lake DGS Summary

Current Configuration			
Genset Model	Cat 3512B	Cat C27	Cat 3412
Genset Rating (kW)	1000	635	400
Genset Speed (rpm)	1200	1800	1800
Genset Hours	N/A	N/A	N/A
Number of fuel tanks	8		
Total bulk fuel storage (L)	400,000		
2018 Peak Demand (kW)	N/A		
Generation Limit (kW)	2035		
Electrical Limit (kVA)	1600		
Number of existing tanks required in 2061	6		





Summary

The Wunnumin DGS was in very good condition when inspected in 2016.

The genset hours are not know but the 3512 and C27 will likely have plenty of life left for backup generation. The 3412 is an older model so could have a lot of hours on it. If it does, it may need replacement prior to the transmission system connection. If it is still installed at that point, it could be useful for backup after an inspection and any recommended maintenance completed. A few months prior to backup service, Remotes would like to do a survey of the generating assets to determine if they require any work to ensure they are reliable for backup generation. Labour costs for this inspection have been included.

The generation portion of the station is sized to provide full backup until the late 2030's. The electrical portion will restrict full backup capability in about 2030.

There were some signs of light staining on the ground near barrels of oil stored in the yard. It could be just near the surface. A proper assessment would be required to determine the extent.

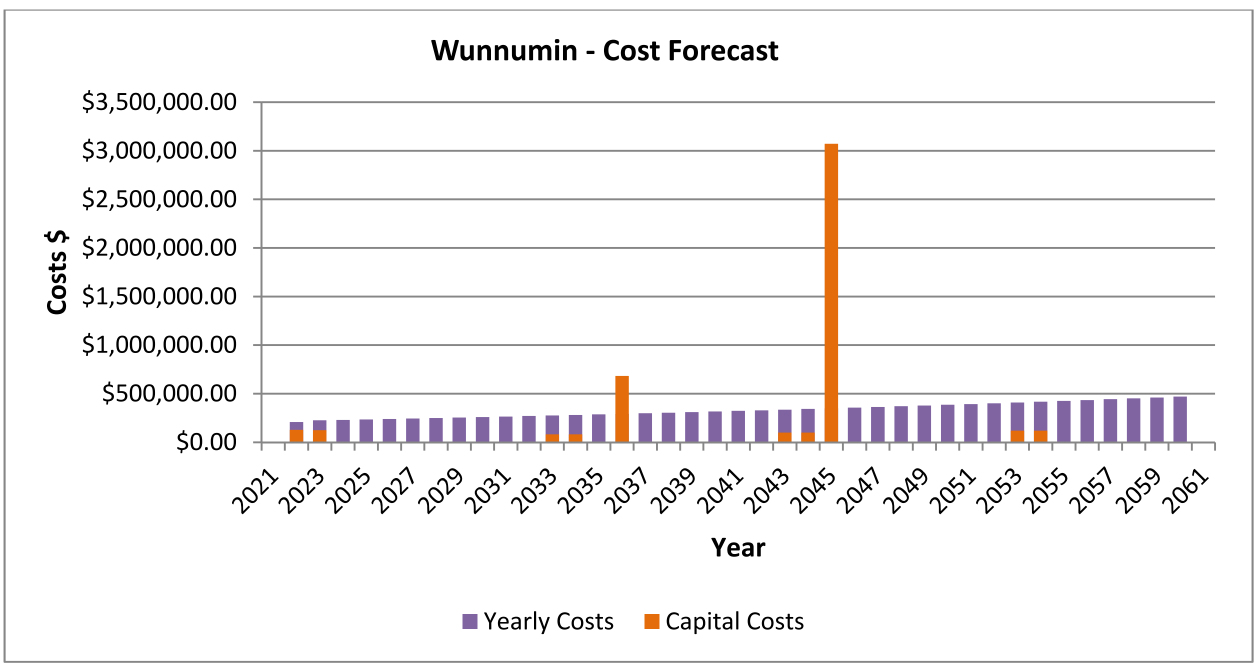
Prior To Backup Service
Dispose of excess fuel, install communications, install fencing and secure yard, install electrical connection for station service, investigate and install modifications to programming.

Short Term Requirements
Mothball two redundant bulk tanks or remove them for use elsewhere.

Potential Long Term Requirements
Upgrades to the electrical equipment around 2030 would increase the capability of the station for a few years until the generating equipment becomes a limitation.

Installation of a 2MW unit to run in parallel with the DGS would satisfy backup demand until 2061.

Cost Summary (2.7% growth)



APPENDIX 2 – COST SUMMARY (WITH CAPITAL UPGRADES)

Back Up Generation
Summary of Costs
2.7% Growth

WITH CAPITAL UPGRADES

Site / Year	Item	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Site		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Bearskin Lake																
	Capital		$ 125,000										$ 81,000	$ 81,000		
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000	$ 316,000	$ 322,000	$ 328,000	$ 335,000
Deer Lake																
	Capital	$ 123,000											$ 81,000	$ 81,000		$ 656,000
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Kasabonika Lake																
	Capital			$ 128,000									$ 618,000		$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Keewaywin																
	Capital / IPA Initial		$ 478,000	$ 249,000											$ 81,000.00	$ 81,000.00
	O&M				$ 249,000.00	$ 280,000.00	$ 286,000.00	$ 292,000.00	$ 298,000.00	$ 304,000.00	$ 310,000.00	$ 316,000.00	$ 322,000.00	$ 329,000.00	$ 335,000.00	$ 342,000.00
Kingfisher																
	Capital	$ 123,000											$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Muskrat Dam																
	Capital / IPA Initial	$ 123,000	$ 119,000										$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
North Spirit Lake																
	Capital / IPA Initial			$ 128,000	$ 124,000		$ 538,000								$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Pikangikum																
	Capital / New Yard		$ 125,000	$ 3,700,000									$ 37,000	$ 2,412,000		
	O&M		$ 195,000	$ 211,000	$ 215,000	$ 220,000	$ 224,000	$ 228,000	$ 233,000	$ 238,000	$ 242,000	$ 247,000	$ 252,000	$ 257,000	$ 262,000	$ 268,000
Poplar Hill																
	Capital / IPA Initial	$ 123,000	$ 119,000										$ 81,000	$ 81,000		$ 656,000
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Sachigo Lake																
	Capital		$ 125,000											$ 81,000	$ 81,000	
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000	$ 316,000	$ 322,000	$ 328,000	$ 335,000
Sandy Lake																
	Capital			$ 128,000											$ 81,000	$ 618,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Wapekeka																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Wawakepewin																
	Capital / 300 kW Unit		$ 125,000	$ 487,000										$ 81,000	$ 81,000	
	O&M			$ 183,600	$ 202,709	$ 206,763	$ 210,899	$ 215,117	$ 219,419	$ 223,807	$ 228,284	$ 232,849	$ 237,506	$ 242,256	$ 247,101	$ 252,043
Weagamow (North Caribou Lake)																
	Capital	$ 123,000											$ 81,000	$ 631,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Wunnumin Lake																
	Capital / IPA Initial			$ 128,000	$ 124,000										$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Fuel			$ 664,000	$ 689,000	$ 716,000	$ 744,000	$ 775,000	$ 806,000	$ 839,000	$ 873,000	$ 908,000	$ 944,000	$ 982,000	$ 1,021,000	$ 1,062,000	$ 1,103,000
Subtotal		$ 615,000	$ 3,270,000	$ 8,071,000	$ 4,983,000	$ 5,026,000	$ 5,685,000	$ 5,265,000	$ 5,391,000	$ 5,512,000	$ 5,639,000	$ 5,769,000	$ 7,044,000	$ 9,652,000	$ 6,911,000	$ 8,743,000
Cumulative		$ 615,000	$ 3,885,000	$ 11,956,000	$ 16,939,000	$ 21,965,000	$ 27,650,000	$ 32,915,000	$ 38,306,000	$ 43,818,000	$ 49,457,000	$ 55,226,000	$ 62,270,000	$ 71,922,000	$ 78,833,000	$ 87,576,000
Total		$ 615,000	$ 3,270,000	$ 8,071,000	$ 4,983,000	$ 5,026,000	$ 5,685,000	$ 5,265,000	$ 5,391,000	$ 5,512,000	$ 5,639,000	$ 5,769,000	$ 7,044,000	$ 9,652,000	$ 6,911,000	$ 8,743,000

Index	0.02
Genset - 2MW	$1,800,000
Cost of Capital	0%

TOTAL	$ 598,000	IPA Initial Costs
TOTAL	$ 7,686,000	Capital - Transformers & Switchgear Upgrade (Weagamow and KI transformers only)
TOTAL	$ 36,653,000	Capital Genset 2 MW Trailer Unit
TOTAL	$ 4,869,000	Capital 300 kW Unit Containerized Unit Wawakepewin, Pikangikum Site Development
TOTAL	$ 2,011,000	Capital Transitional Costs
TOTAL	$ 9,312,000	Capital Sustainment Costs (10 yr cycle)

Notes: Capital for transitional costs are incurred one year before expect connection date
Yearly costs coincide with connection date year
Sustainment capital (10 yr period) spread over 2 years

Back Up Generation
Summary of Costs
2.7% Growth

Year	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Site	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
Bearskin Lake																
							$ 99,000	$ 99,000					$ 849,000			
	$ 342,000	$ 348,000	$ 355,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 425,000	$ 433,000	$ 442,000	$ 451,000	$ 460,000
Deer Lake																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Kasabonika Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Keewaywin																
									$ 99,000.00	$ 99,000.00						
	$ 349,000.00	$ 356,000.00	$ 363,000.00	$ 370,000.00	$ 377,000.00	$ 385,000.00	$ 393,000.00	$ 401,000.00	$ 409,000.00	$ 417,000.00	$ 425,000.00	$ 434,000.00	$ 442,000.00	$ 451,000.00	$ 460,000.00	$ 469,000.00
Kingfisher																
							$ 99,000	$ 99,000								$ 901,000
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)																
		$ 510,000							$ 99,000	$ 99,000	$ 3,072,000					
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Muskrat Dam																
							$ 99,000	$ 99,000							$ 3,326,000	
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
North Spirit Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Pikangikum																
							$ 48,000	$ 48,000	$ 2,953,000							
	$ 273,000	$ 279,000	$ 284,000	$ 290,000	$ 296,000	$ 301,000	$ 307,000	$ 314,000	$ 320,000	$ 326,000	$ 333,000	$ 339,000	$ 346,000	$ 353,000	$ 360,000	$ 367,000
Poplar Hill																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Sachigo Lake																
				$ 710,000				$ 99,000	$ 99,000							
	$ 342,000	$ 348,000	$ 355,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 425,000	$ 433,000	$ 442,000	$ 451,000	$ 460,000
Sandy Lake																
								$ 2,895,000	$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Wapekeka																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Wawakepewin																
	$ 682,000							$ 99,000	$ 99,000							
	$ 257,084	$ 262,226	$ 267,471	$ 272,820	$ 278,276	$ 283,842	$ 289,519	$ 295,309	$ 301,215	$ 307,240	$ 313,384	$ 319,652	$ 326,045	$ 332,566	$ 339,217	$ 346,002
Weagamow (North Caribou Lake)																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Wunnumin Lake																
		$ 683,000							$ 99,000	$ 99,000	$ 3,072,000					
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Fuel	$ 1,148,000	$ 1,195,000	$ 1,243,000	$ 1,294,000	$ 1,345,000	$ 1,399,000	$ 1,455,000	$ 1,512,000	$ 1,572,000	$ 1,634,000	$ 1,694,000	$ 1,756,000	$ 1,821,000	$ 1,888,000	$ 1,957,000	$ 2,028,000
Subtotal	$ 7,162,000	$ 7,822,000	$ 6,785,000	$ 7,658,000	$ 7,108,000	$ 7,278,000	$ 8,100,000	$ 11,367,000	$ 11,660,000	$ 8,695,000	$ 14,331,000	$ 8,383,000	$ 9,422,000	$ 8,780,000	$ 12,314,000	$ 10,095,000
Cumulative	$ 94,738,000	$ 102,560,000	$ 109,345,000	$ 117,003,000	$ 124,111,000	$ 131,389,000	$ 139,489,000	$ 150,856,000	$ 162,516,000	$ 171,211,000	$ 185,542,000	$ 193,925,000	$ 203,347,000	$ 212,127,000	$ 224,441,000	$ 234,536,000
Total	$ 7,162,000	$ 7,822,000	$ 6,785,000	$ 7,658,000	$ 7,108,000	$ 7,278,000	$ 8,100,000	$ 11,367,000	$ 11,660,000	$ 8,695,000	$ 14,331,000	$ 8,383,000	$ 9,422,000	$ 8,780,000	$ 12,314,000	$ 10,095,000

Back Up Generation
Summary of Costs
2.7% Growth

Year	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Site	33	34	35	36	37	38	39	40	41	42	43
Bearskin Lake											
	$ 120,000	$ 120,000									
	$ 469,000	$ 478,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000
Deer Lake											
	$ 120,000	$ 120,000		$ 3,672,000							
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
Kasabonika Lake											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Keewaywin											
			$ 120,000	$ 3,792,000							
	$ 479,000.00	$ 488,000.00	$ 498,000.00	$ 508,000.00	$ 518,000.00	$ 528,000.00	$ 539,000.00	$ 550,000.00	$ 561,000.00	$ 572,000.00	$ 583,000.00
Kingfisher											
	$ 120,000	$ 120,000									
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Muskrat Dam											
	$ 120,000	$ 120,000									
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
North Spirit Lake											
			$ 120,000	$ 120,000				$ 3,974,000			
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Pikangikum											
	$ 71,000	$ 71,000									
	$ 375,000	$ 382,000	$ 390,000	$ 398,000	$ 406,000	$ 414,000	$ 422,000	$ 431,000	$ 439,000	$ 448,000	$ 457,000
Poplar Hill											
	$ 120,000	$ 120,000			$ 3,745,000						
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
Sachigo Lake											
		$ 120,000	$ 120,000								
	$ 469,000	$ 478,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000
Sandy Lake											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Wapekeka											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Wawakepewin											
		$ 120,000	$ 120,000								
	$ 352,922	$ 359,980	$ 367,180	$ 374,523	$ 382,014	$ 389,654	$ 397,447	$ 405,396	$ 413,504	$ 421,774	$ 430,210
Weagamow (North Caribou Lake)											
	$ 120,000	$ 120,000					$ 3,897,000				
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
Wunnumin Lake											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Fuel	$ 2,102,000	$ 2,179,000	$ 2,258,000	$ 2,340,000	$ 2,425,000	$ 2,513,000	$ 2,605,000	$ 2,699,000	$ 2,797,000	$ 2,898,000	$ 3,003,000
Subtotal	$ 10,207,000	$ 10,669,000	$ 10,947,000	$ 18,289,000	$ 14,085,000	$ 10,584,000	$ 14,735,000	$ 15,077,000	$ 11,367,000	$ 11,639,000	$ 11,915,000
Cumulative	$ 244,743,000	$ 255,412,000	$ 266,359,000	$ 284,648,000	$ 298,733,000	$ 309,317,000	$ 324,052,000	$ 339,129,000	$ 350,496,000	$ 362,135,000	$ 374,050,000
Total	$ 10,207,000	$ 10,669,000	$ 10,947,000	$ 18,289,000	$ 14,085,000	$ 10,584,000	$ 14,735,000	$ 15,077,000	$ 11,367,000	$ 11,639,000	$ 11,915,000

GRAND TOTAL $ 374,050,000

Back Up Generation
Summary of Costs
4.0% Growth

WITH CAPITAL UPGRADES

Year	Item	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Site		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Bearskin Lake																
	Capital		$ 125,000										$ 81,000	$ 81,000		
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000	$ 316,000	$ 322,000	$ 328,000	$ 335,000
Deer Lake																
	Capital	$ 123,000									$ 594,000		$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Kasabonika Lake																
	Capital			$ 128,000					$ 571,000						$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Keewaywin																
	Capital / IPA Initial		$ 478,000	$ 249,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Kingfisher																
	Capital	$ 123,000											$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)																
	Capital			$ 128,000									$ 462,000		$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Muskrat Dam																
	Capital / IPA Initial	$ 123,000	$ 119,000										$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
North Spirit Lake																
	Capital / IPA Initial			$ 128,000	$ 652,000										$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Pikangikum																
	Capital / New Yard		$ 125,000	$ 3,700,000								$ 2,283,000	$ 37,000	$ 37,000		
	O&M		$ 195,000	$ 211,000	$ 215,000	$ 220,000	$ 224,000	$ 228,000	$ 233,000	$ 238,000	$ 242,000	$ 247,000	$ 252,000	$ 257,000	$ 262,000	$ 268,000
Poplar Hill																
	Capital / IPA Initial	$ 123,000	$ 119,000								$ 594,000		$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Sachigo Lake																
	Capital		$ 125,000										$ 618,000	$ 81,000	$ 81,000	
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000	$ 316,000	$ 322,000	$ 328,000	$ 335,000
Sandy Lake																
	Capital			$ 128,000							$ 594,000				$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Wapekeka																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Wawakepewin																
	Capital / 300 kW Unit		$ 125,000	$ 487,000										$ 81,000	$ 81,000	
	O&M			$ 199,000	$ 220,000	$ 224,000	$ 229,000	$ 233,000	$ 238,000	$ 243,000	$ 247,000	$ 252,000	$ 257,000	$ 263,000	$ 268,000	$ 273,000
Weagamow (North Caribou Lake)																
	Capital	$ 123,000								$ 583,000		$ 453,000	$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Wunnumin Lake																
	Capital / IPA Initial			$ 128,000	$ 124,000								$ 618,344		$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Fuel			$ 687,000	$ 721,000	$ 758,000	$ 797,000	$ 839,000	$ 884,000	$ 931,000	$ 980,000	$ 1,031,000	$ 1,086,000	$ 1,143,000	$ 1,203,000	$ 1,265,000	$ 1,331,000
Subtotal		$ 615,000	$ 3,293,000	$ 8,118,000	$ 5,570,000	$ 5,096,000	$ 5,229,000	$ 5,361,000	$ 6,073,000	$ 6,221,000	$ 7,563,000	$ 8,666,000	$ 8,304,000	$ 6,930,000	$ 7,135,000	$ 7,143,000
Cumulative		$ 615,000	$ 3,908,000	$ 12,026,000	$ 17,596,000	$ 22,692,000	$ 27,921,000	$ 33,282,000	$ 39,355,000	$ 45,576,000	$ 53,139,000	$ 61,805,000	$ 70,109,000	$ 77,039,000	$ 84,174,000	$ 91,317,000
Total		$ 615,000	$ 3,293,000	$ 8,118,000	$ 5,570,000	$ 5,096,000	$ 5,229,000	$ 5,361,000	$ 6,073,000	$ 6,221,000	$ 7,563,000	$ 8,666,000	$ 8,304,000	$ 6,930,000	$ 7,135,000	$ 7,143,000

Index	0.02
Genset - 2MW 2018 Cost	$1,800,000
Cost of Capital	0%

TOTAL	$ 607,000.00	IPA Initial Costs for Site Review and Operator Training
TOTAL	$ 8,597,343.97	Capital Transformers & Switchgear Upgrade (Weagamow and KI transformers only)
TOTAL	$ 47,255,000.00	Capital Genset 2 MW trailer unit
TOTAL	$ 4,869,000.00	Capital 300 kW Unit Containerized Unit Wawakepewin, Pikangikum Site Development
TOTAL	$ 2,001,000.00	Capital Transitional Capital Costs
TOTAL	$ 15,056,000.00	Capital Sustainment Costs (10 yr cycle)

Notes: Capital for transitional costs are incurred one year before expect connection date
Yearly costs coincide with connection date year
Sustainment capital (10 yr period) spread over 2 years

Back Up Generation
Summary of Costs
4.0% Growth

Year	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Site	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
Bearskin Lake																
				$ 710,000			$ 99,000	$ 99,000				$ 3,134,000				
	$ 342,000	$ 348,000	$ 355,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 425,000	$ 433,000	$ 442,000	$ 451,000	$ 460,000
Deer Lake																
							$ 99,000	$ 99,000	$ 3,134,000							
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Kasabonika Lake																
									$ 99,000	$ 99,000			$ 3,134,000			
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Keewaywin																
									$ 3,052,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Kingfisher																
						$ 739,000	$ 99,000	$ 99,000								$ 3,460,000
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)																
			$ 2,571,000						$ 3,052,000	$ 3,052,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Muskrat Dam																
					$ 2,728,000		$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
North Spirit Lake																
									$ 99,000	$ 99,000	$ 3,072,000					
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Pikangikum																
						$ 2,783,000	$ 48,000	$ 48,000								
	$ 273,000	$ 279,000	$ 284,000	$ 290,000	$ 296,000	$ 301,000	$ 307,000	$ 314,000	$ 320,000	$ 326,000	$ 333,000	$ 339,000	$ 346,000	$ 353,000	$ 360,000	$ 367,000
Poplar Hill																
							$ 99,000	$ 99,000		$ 3,012,000						
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Sachigo Lake																
								$ 99,000	$ 99,000				$ 3,197,000			
	$ 342,000	$ 348,000	$ 355,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 425,000	$ 433,000	$ 442,000	$ 451,000	$ 460,000
Sandy Lake																
		$ 2,571,000							$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Wapekeka																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Wawakepewin																
	$ 682,000							$ 99,000	$ 99,000							
	$ 279,000	$ 284,000	$ 290,000	$ 296,000	$ 302,000	$ 308,000	$ 314,000	$ 320,000	$ 326,000	$ 333,000	$ 340,000	$ 346,000	$ 353,000	$ 360,000	$ 368,000	$ 375,000
Weagamow (North Caribou Lake)																
							$ 99,000	$ 99,000			$ 3,072,000					
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Wunnumin Lake																
			$ 2,622,000						$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Fuel	$ 1,403,000	$ 1,477,000	$ 1,556,000	$ 1,639,000	$ 1,726,000	$ 1,817,000	$ 1,912,000	$ 2,013,000	$ 2,119,000	$ 2,229,000	$ 2,341,000	$ 2,458,000	$ 2,580,000	$ 2,708,000	$ 2,843,000	$ 2,984,000
Subtotal	$ 7,439,000	$ 9,504,000	$ 12,314,000	$ 8,026,000	$ 10,241,000	$ 11,242,000	$ 8,581,000	$ 8,998,000	$ 18,319,000	$ 15,281,000	$ 15,005,000	$ 12,245,000	$ 15,690,000	$ 9,627,000	$ 9,903,000	$ 13,639,000
Cumulative	$ 98,756,000	$ 108,260,000	$ 120,574,000	$ 128,600,000	$ 138,841,000	$ 150,083,000	$ 158,664,000	$ 167,662,000	$ 185,981,000	$ 201,262,000	$ 216,267,000	$ 228,512,000	$ 244,202,000	$ 253,829,000	$ 263,732,000	$ 277,371,000
Total	$ 7,439,000	$ 9,504,000	$ 12,314,000	$ 8,026,000	$ 10,241,000	$ 11,242,000	$ 8,581,000	$ 8,998,000	$ 18,319,000	$ 15,281,000	$ 15,005,000	$ 12,245,000	$ 15,690,000	$ 9,627,000	$ 9,903,000	$ 13,639,000

Back Up Generation
Summary of Costs
4.0% Growth

Year	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061		
Site	33	34	35	36	37	38	39	40	41	42	43		
Bearskin Lake													
	$ 120,000	$ 120,000											
	$ 469,000	$ 478,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000		
Deer Lake													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
Kasabonika Lake													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Keewaywin													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Kingfisher													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Muskrat Dam													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
North Spirit Lake													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Pikangikum													
	$ 71,000	$ 71,000											
	$ 375,000	$ 382,000	$ 390,000	$ 398,000	$ 406,000	$ 414,000	$ 422,000	$ 431,000	$ 439,000	$ 448,000	$ 457,000		
Poplar Hill													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
Sachigo Lake													
		$ 120,000	$ 120,000										
	$ 469,000	$ 478,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000		
Sandy Lake													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Wapekeka													
		$ 3,529,000	$ 120,000	$ 120,000				$ 1,055,000					
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Wawakepewin													
		$ 120,000	$ 120,000										
	$ 383,000	$ 390,000	$ 398,000	$ 406,000	$ 414,000	$ 422,000	$ 431,000	$ 439,000	$ 448,000	$ 457,000	$ 466,000		
Weagamow (North Caribou Lake)													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
Wunnumin Lake													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Fuel	$ 3,132,000	$ 3,287,000	$ 3,449,000	$ 3,620,000	$ 3,800,000	$ 3,988,000	$ 4,186,000	$ 4,393,000	$ 4,611,000	$ 4,838,000	$ 5,077,000		
Subtotal	$ 11,267,000	$ 15,336,000	$ 12,169,000	$ 12,256,000	$ 11,747,000	$ 12,091,000	$ 12,453,000	$ 13,886,000	$ 13,215,000	$ 13,614,000	$ 14,025,000		
Cumulative	$ 288,638,000	$ 303,974,000	$ 316,143,000	$ 328,399,000	$ 340,146,000	$ 352,237,000	$ 364,690,000	$ 378,576,000	$ 391,791,000	$ 405,405,000	$ 419,430,000		
Total	$ 11,267,000	$ 15,336,000	$ 12,169,000	$ 12,256,000	$ 11,747,000	$ 12,091,000	$ 12,453,000	$ 13,886,000	$ 13,215,000	$ 13,614,000	$ 14,025,000	**GRAND TOTAL**	**$ 419,430,000.00**

Supporting Rationale	Operator Costs / YR 1	Maintenance & IPA Initial Costs / YR 1	Emergency & Unplanned / YR 1	Utility Costs / YR 1	Capital Costs / YR	Upgrades
	Half Current Hours	RMM, RME & Operations for 2 weeks	Urgent work	Electricity / communications	Small scale plant improvements to prolong asset life	Trailer unit or transformer purchase and switchgear
	$2,500 / month, no OT	Minor repairs, fluid changes, checks		$ 747 ave - sat / $737 ave - fibre monthly	Transitional costs - communications, control modifications, electric space heat, electric block heat, drain secondary	Set-up, commission
Bearskin Lake				Electricity 250 MWh / year, 60 F room temp, block heat 78 MWh / year - 328 MWh total	70 h - Design, 3 wks - HH M&E	
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00	Varies - Refer to cost tab	Varies - Refer to cost tab
Deer Lake (without Hydel)						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00	Includes removing 600 V MTO feed	
Kasabonika Lake						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Keewaywin						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Review of IPA Station, Operator Training		$ 112,000.00				
Kingfisher						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Muskrat Dam						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Review of IPA Station, Operator Training		$ 112,000.00				
North Spirit Lake						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Review of IPA Station, Operator Training		$ 112,000.00				
Poplar Hill						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Review of IPA Station, Operator Training		$ 112,000.00				
Sachigo Lake						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Sandy Lake						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Wapekeka						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Weagamow (North Caribou Lake)						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Wunnumin Lake						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 67,452.00		
Review of IPA Station, Operator Training		$ 112,000.00				
Non - Standard Configuration						
Pikangikum						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 25,900.00		
Wawakepewin						
	$ 30,000.00	$ 90,700.00	$ 37,000.00	$ 25,900.00		
Total	**$ 480,000.00**	**$ 2,011,200.00**	**$ 592,000.00**	**$ 996,128.00**		

APPENDIX 3 – COST SUMMARY (WITHOUT CAPITAL UPGRADES)

Back Up Generation
Summary of Costs
2.7% Growth

WITHOUT CAPITAL UPGRADES

Year	Item	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Site		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Bearskin Lake																
	Capital		$ 125,000										$ 81,000	$ 81,000		
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000	$ 316,000	$ 322,000	$ 328,000	$ 335,000
Deer Lake																
	Capital	$ 123,000											$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Kasabonika Lake																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Keewaywin																
	Capital / IPA Initial			$ 249,000											$ 81,000.00	$ 81,000.00
	O&M				$ 249,000.00	$ 280,000.00	$ 286,000.00	$ 292,000.00	$ 298,000.00	$ 304,000.00	$ 310,000.00	$ 316,000.00	$ 322,000.00	$ 329,000.00	$ 335,000.00	$ 342,000.00
Kingfisher																
	Capital	$ 123,000											$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Muskrat Dam																
	Capital / IPA Initial	$ 123,000	$ 119,000										$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
North Spirit Lake																
	Capital / IPA Initial			$ 128,000	$ 124,000										$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Pikangikum																
	Capital / New Yard		$ 125,000	$ 3,700,000									$ 37,000	$ 37,000		
	O&M		$ 195,000	$ 211,000	$ 215,000	$ 220,000	$ 224,000	$ 228,000	$ 233,000	$ 238,000	$ 242,000	$ 247,000	$ 252,000	$ 257,000	$ 262,000	$ 268,000
Poplar Hill																
	Capital / IPA Initial	$ 123,000	$ 119,000										$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Sachigo Lake																
	Capital		$ 125,000											$ 81,000	$ 81,000	
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000	$ 316,000	$ 322,000	$ 328,000	$ 335,000
Sandy Lake																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Wapekeka																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Wawakepewin																
	Capital / 300 kW Unit		$ 125,000	$ 487,000										$ 81,000	$ 81,000	
	O&M			$ 183,600	$ 202,709	$ 206,763	$ 210,899	$ 215,117	$ 219,419	$ 223,807	$ 228,284	$ 232,849	$ 237,506	$ 242,256	$ 247,101	$ 252,043
Weagamow (North Caribou Lake)																
	Capital	$ 123,000											$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Wunnumin Lake																
	Capital / IPA Initial			$ 128,000	$ 124,000										$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Fuel			$ 664,000	$ 689,000	$ 716,000	$ 744,000	$ 775,000	$ 806,000	$ 839,000	$ 873,000	$ 908,000	$ 944,000	$ 982,000	$ 1,021,000	$ 1,062,000	$ 1,103,000
Subtotal		$ 615,000	$ 2,792,000	$ 8,071,000	$ 4,983,000	$ 5,026,000	$ 5,147,000	$ 5,265,000	$ 5,391,000	$ 5,512,000	$ 5,639,000	$ 5,769,000	$ 6,426,000	$ 6,727,000	$ 6,911,000	$ 6,894,000
Cumulative		$ 615,000	$ 3,407,000	$ 11,478,000	$ 16,461,000	$ 21,487,000	$ 26,634,000	$ 31,899,000	$ 37,290,000	$ 42,802,000	$ 48,441,000	$ 54,210,000	$ 60,636,000	$ 67,363,000	$ 74,274,000	$ 81,168,000
Total		$ 615,000	$ 2,792,000	$ 8,071,000	$ 4,983,000	$ 5,026,000	$ 5,147,000	$ 5,265,000	$ 5,391,000	$ 5,512,000	$ 5,639,000	$ 5,769,000	$ 6,426,000	$ 6,727,000	$ 6,911,000	$ 6,894,000

Index	0.02	TOTAL	$ 598,000	IPA Initial Costs
Genset - 2MW	$1,800,000	TOTAL	$ -	Capital - Transformers & Switchgear Upgrade (Weagamow and KI transformers only)
Cost of Capital	0%	TOTAL	$ -	Capital Genset 2 MW Trailer Unit
		TOTAL	$ 4,187,000	Capital 300 kW Unit Containerized Unit Wawakepewin, Pikangikum Site Development (Initial generation assets)
		TOTAL	$ 2,011,000	Capital Transitional Costs
		TOTAL	$ 9,312,000	Capital Sustainment Costs (10 yr cycle)

Notes: Capital for transitional costs are incurred one year before expect connection date
Yearly costs coincide with connection date year
Sustainment capital (10 yr period) spread over 2 years

Back Up Generation
Summary of Costs
2.7% Growth

Year	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Site	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
Bearskin Lake																
							$ 99,000	$ 99,000								
	$ 342,000	$ 348,000	$ 355,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 425,000	$ 433,000	$ 442,000	$ 451,000	$ 460,000
Deer Lake																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Kasabonika Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Keewaywin																
									$ 99,000.00	$ 99,000.00						
	$ 349,000.00	$ 356,000.00	$ 363,000.00	$ 370,000.00	$ 377,000.00	$ 385,000.00	$ 393,000.00	$ 401,000.00	$ 409,000.00	$ 417,000.00	$ 425,000.00	$ 434,000.00	$ 442,000.00	$ 451,000.00	$ 460,000.00	$ 469,000.00
Kingfisher																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Muskrat Dam																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
North Spirit Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Pikangikum																
							$ 48,000	$ 48,000								
	$ 273,000	$ 279,000	$ 284,000	$ 290,000	$ 296,000	$ 301,000	$ 307,000	$ 314,000	$ 320,000	$ 326,000	$ 333,000	$ 339,000	$ 346,000	$ 353,000	$ 360,000	$ 367,000
Poplar Hill																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Sachigo Lake																
								$ 99,000	$ 99,000							
	$ 342,000	$ 348,000	$ 355,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 425,000	$ 433,000	$ 442,000	$ 451,000	$ 460,000
Sandy Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Wapekeka																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Wawakepewin																
								$ 99,000	$ 99,000							
	$ 257,084	$ 262,226	$ 267,471	$ 272,820	$ 278,276	$ 283,842	$ 289,519	$ 295,309	$ 301,215	$ 307,240	$ 313,384	$ 319,652	$ 326,045	$ 332,566	$ 339,217	$ 346,002
Weagamow (North Caribou Lake)																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Wunnumin Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Fuel	$ 1,148,000	$ 1,195,000	$ 1,243,000	$ 1,294,000	$ 1,345,000	$ 1,399,000	$ 1,455,000	$ 1,512,000	$ 1,572,000	$ 1,634,000	$ 1,694,000	$ 1,756,000	$ 1,821,000	$ 1,888,000	$ 1,957,000	$ 2,028,000
Subtotal	$ 6,480,000	$ 6,629,000	$ 6,785,000	$ 6,948,000	$ 7,108,000	$ 7,278,000	$ 8,100,000	$ 8,472,000	$ 8,707,000	$ 8,695,000	$ 8,187,000	$ 8,383,000	$ 8,573,000	$ 8,780,000	$ 8,988,000	$ 9,194,000
Cumulative	$ 87,648,000	$ 94,277,000	$ 101,062,000	$ 108,010,000	$ 115,118,000	$ 122,396,000	$ 130,496,000	$ 138,968,000	$ 147,675,000	$ 156,370,000	$ 164,557,000	$ 172,940,000	$ 181,513,000	$ 190,293,000	$ 199,281,000	$ 208,475,000
Total	$ 6,480,000	$ 6,629,000	$ 6,785,000	$ 6,948,000	$ 7,108,000	$ 7,278,000	$ 8,100,000	$ 8,472,000	$ 8,707,000	$ 8,695,000	$ 8,187,000	$ 8,383,000	$ 8,573,000	$ 8,780,000	$ 8,988,000	$ 9,194,000

Back Up Generation
Summary of Costs
2.7% Growth

Year	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Site	33	34	35	36	37	38	39	40	41	42	43
Bearskin Lake											
	$ 120,000	$ 120,000									
	$ 469,000	$ 478,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000
Deer Lake											
	$ 120,000	$ 120,000									
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
Kasabonika Lake											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Keewaywin											
			$ 120,000	$ 120,000							
	$ 479,000.00	$ 488,000.00	$ 498,000.00	$ 508,000.00	$ 518,000.00	$ 528,000.00	$ 539,000.00	$ 550,000.00	$ 561,000.00	$ 572,000.00	$ 583,000.00
Kingfisher											
	$ 120,000	$ 120,000									
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Muskrat Dam											
	$ 120,000	$ 120,000									
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
North Spirit Lake											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Pikangikum											
	$ 71,000	$ 71,000									
	$ 375,000	$ 382,000	$ 390,000	$ 398,000	$ 406,000	$ 414,000	$ 422,000	$ 431,000	$ 439,000	$ 448,000	$ 457,000
Poplar Hill											
	$ 120,000	$ 120,000									
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
Sachigo Lake											
		$ 120,000	$ 120,000								
	$ 469,000	$ 478,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000
Sandy Lake											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Wapekeka											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Wawakepewin											
		$ 120,000	$ 120,000								
	$ 352,922	$ 359,980	$ 367,180	$ 374,523	$ 382,014	$ 389,654	$ 397,447	$ 405,396	$ 413,504	$ 421,774	$ 430,210
Weagamow (North Caribou Lake)											
	$ 120,000	$ 120,000									
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000
Wunnumin Lake											
			$ 120,000	$ 120,000							
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000
Fuel	$ 2,102,000	$ 2,179,000	$ 2,258,000	$ 2,340,000	$ 2,425,000	$ 2,513,000	$ 2,605,000	$ 2,699,000	$ 2,797,000	$ 2,898,000	$ 3,003,000
Subtotal	$ 10,207,000	$ 10,669,000	$ 10,947,000	$ 10,945,000	$ 10,340,000	$ 10,584,000	$ 10,838,000	$ 11,103,000	$ 11,367,000	$ 11,639,000	$ 11,915,000
Cumulative	$ 218,682,000	$ 229,351,000	$ 240,298,000	$ 251,243,000	$ 261,583,000	$ 272,167,000	$ 283,005,000	$ 294,108,000	$ 305,475,000	$ 317,114,000	$ 329,029,000
Total	$ 10,207,000	$ 10,669,000	$ 10,947,000	$ 10,945,000	$ 10,340,000	$ 10,584,000	$ 10,838,000	$ 11,103,000	$ 11,367,000	$ 11,639,000	$ 11,915,000

GRAND TOTAL $ 329,029,000

Back Up Generation
Summary of Costs
4.0% Growth

WITHOUT CAPITAL UPGRADES

Site	Item	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
		2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Bearskin Lake																
	Capital		$ 125,000										$ 81,000	$ 81,000		
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000	$ 316,000	$ 322,000	$ 328,000	$ 335,000
Deer Lake																
	Capital	$ 123,000											$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Kasabonika Lake																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Keewaywin																
	Capital / IPA Initial			$ 249,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Kingfisher																
	Capital	$ 123,000											$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Muskrat Dam																
	Capital / IPA Initial	$ 123,000	$ 119,000										$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
North Spirit Lake																
	Capital / IPA Initial			$ 128,000	$ 124,000										$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Pikangikum																
	Capital / New Yard		$ 125,000	$ 3,700,000									$ 37,000	$ 37,000		
	O&M		$ 195,000	$ 211,000	$ 215,000	$ 220,000	$ 224,000	$ 228,000	$ 233,000	$ 238,000	$ 242,000	$ 247,000	$ 252,000	$ 257,000	$ 262,000	$ 268,000
Poplar Hill																
	Capital / IPA Initial	$ 123,000	$ 119,000										$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Sachigo Lake																
	Capital		$ 125,000											$ 81,000	$ 81,000	
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000	$ 316,000	$ 322,000	$ 328,000	$ 335,000
Sandy Lake																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Wapekeka																
	Capital			$ 128,000											$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Wawakepewin																
	Capital / 300 kW Unit		$ 125,000	$ 487,000										$ 81,000	$ 81,000	
	O&M			$ 199,000	$ 220,000	$ 224,000	$ 229,000	$ 233,000	$ 238,000	$ 243,000	$ 247,000	$ 252,000	$ 257,000	$ 263,000	$ 268,000	$ 273,000
Weagamow (North Caribou Lake)																
	Capital	$ 123,000											$ 81,000	$ 81,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000	$ 309,000	$ 315,000	$ 322,000	$ 328,000
Wunnumin Lake																
	Capital / IPA Initial			$ 128,000	$ 124,000										$ 81,000	$ 81,000
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000	$ 322,000	$ 329,000	$ 335,000	$ 342,000
Fuel			$ 687,000	$ 721,000	$ 758,000	$ 797,000	$ 839,000	$ 884,000	$ 931,000	$ 980,000	$ 1,031,000	$ 1,086,000	$ 1,143,000	$ 1,203,000	$ 1,265,000	$ 1,331,000
Subtotal		$ 615,000	$ 2,815,000	$ 8,118,000	$ 5,042,000	$ 5,096,000	$ 5,229,000	$ 5,361,000	$ 5,502,000	$ 5,638,000	$ 5,781,000	$ 5,930,000	$ 6,606,000	$ 6,930,000	$ 7,135,000	$ 7,143,000
Cumulative		$ 615,000	$ 3,430,000	$ 11,548,000	$ 16,590,000	$ 21,686,000	$ 26,915,000	$ 32,276,000	$ 37,778,000	$ 43,416,000	$ 49,197,000	$ 55,127,000	$ 61,733,000	$ 68,663,000	$ 75,798,000	$ 82,941,000
Total		$ 615,000	$ 2,815,000	$ 8,118,000	$ 5,042,000	$ 5,096,000	$ 5,229,000	$ 5,361,000	$ 5,502,000	$ 5,638,000	$ 5,781,000	$ 5,930,000	$ 6,606,000	$ 6,930,000	$ 7,135,000	$ 7,143,000

Index	0.02
Genset - 2MW 2018 Cost	$1,800,000
Cost of Capital	0%

TOTAL	$ 607,000.00	IPA Initial Costs for Site Review and Operator Training
TOTAL	$ -	Capital Transformers & Switchgear Upgrade (Weagamow and KI transformers only)
TOTAL	$ -	Capital Genset 2 MW trailer unit
TOTAL	$ 4,187,000.00	Capital 300 kW Unit Containerized Unit Wawakepewin, Pikangikum Site Development (Initial generation assets)
TOTAL	$ 2,001,000.00	Capital Transitional Capital Costs
TOTAL	$ 9,312,000.00	Capital Sustainment Costs (10 yr cycle)

Notes: Capital for transitional costs are incurred one year before expect connection date
Yearly costs coincide with connection date year
Sustainment capital (10 yr period) spread over 2 years

Back Up Generation
Summary of Costs
4.0% Growth

Year	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Site	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
Bearskin Lake																
							$ 99,000	$ 99,000								
	$ 342,000	$ 348,000	$ 355,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 425,000	$ 433,000	$ 442,000	$ 451,000	$ 460,000
Deer Lake																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Kasabonika Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Keewaywin																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Kingfisher																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Muskrat Dam																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
North Spirit Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Pikangikum																
							$ 48,000	$ 48,000								
	$ 273,000	$ 279,000	$ 284,000	$ 290,000	$ 296,000	$ 301,000	$ 307,000	$ 314,000	$ 320,000	$ 326,000	$ 333,000	$ 339,000	$ 346,000	$ 353,000	$ 360,000	$ 367,000
Poplar Hill																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Sachigo Lake																
								$ 99,000	$ 99,000							
	$ 342,000	$ 348,000	$ 355,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 425,000	$ 433,000	$ 442,000	$ 451,000	$ 460,000
Sandy Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Wapekeka																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Wawakepewin																
								$ 99,000	$ 99,000							
	$ 279,000	$ 284,000	$ 290,000	$ 296,000	$ 302,000	$ 308,000	$ 314,000	$ 320,000	$ 326,000	$ 333,000	$ 340,000	$ 346,000	$ 353,000	$ 360,000	$ 368,000	$ 375,000
Weagamow (North Caribou Lake)																
							$ 99,000	$ 99,000								
	$ 335,000	$ 341,000	$ 348,000	$ 355,000	$ 362,000	$ 369,000	$ 377,000	$ 384,000	$ 392,000	$ 400,000	$ 408,000	$ 416,000	$ 424,000	$ 433,000	$ 442,000	$ 450,000
Wunnumin Lake																
									$ 99,000	$ 99,000						
	$ 349,000	$ 356,000	$ 363,000	$ 370,000	$ 377,000	$ 385,000	$ 393,000	$ 401,000	$ 409,000	$ 417,000	$ 425,000	$ 434,000	$ 442,000	$ 451,000	$ 460,000	$ 469,000
Fuel	$ 1,403,000	$ 1,477,000	$ 1,556,000	$ 1,639,000	$ 1,726,000	$ 1,817,000	$ 1,912,000	$ 2,013,000	$ 2,119,000	$ 2,229,000	$ 2,341,000	$ 2,458,000	$ 2,580,000	$ 2,708,000	$ 2,843,000	$ 2,984,000
Subtotal	$ 6,757,000	$ 6,933,000	$ 7,121,000	$ 7,316,000	$ 7,513,000	$ 7,720,000	$ 8,581,000	$ 8,998,000	$ 9,279,000	$ 9,316,000	$ 8,861,000	$ 9,111,000	$ 9,359,000	$ 9,627,000	$ 9,903,000	$ 10,179,000
Cumulative	$ 89,698,000	$ 96,631,000	$ 103,752,000	$ 111,068,000	$ 118,581,000	$ 126,301,000	$ 134,882,000	$ 143,880,000	$ 153,159,000	$ 162,475,000	$ 171,336,000	$ 180,447,000	$ 189,806,000	$ 199,433,000	$ 209,336,000	$ 219,515,000
Total	$ 6,757,000	$ 6,933,000	$ 7,121,000	$ 7,316,000	$ 7,513,000	$ 7,720,000	$ 8,581,000	$ 8,998,000	$ 9,279,000	$ 9,316,000	$ 8,861,000	$ 9,111,000	$ 9,359,000	$ 9,627,000	$ 9,903,000	$ 10,179,000

Back Up Generation
Summary of Costs
4.0% Growth

Year	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061		
Site	33	34	35	36	37	38	39	40	41	42	43		
Bearskin Lake													
	$ 120,000	$ 120,000											
	$ 469,000	$ 478,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000		
Deer Lake													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
Kasabonika Lake													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Keewaywin													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Kingfisher													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Muskrat Dam													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
North Spirit Lake													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Pikangikum													
	$ 71,000	$ 71,000											
	$ 375,000	$ 382,000	$ 390,000	$ 398,000	$ 406,000	$ 414,000	$ 422,000	$ 431,000	$ 439,000	$ 448,000	$ 457,000		
Poplar Hill													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
Sachigo Lake													
		$ 120,000	$ 120,000										
	$ 469,000	$ 478,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000		
Sandy Lake													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Wapekeka													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Wawakepewin													
		$ 120,000	$ 120,000										
	$ 383,000	$ 390,000	$ 398,000	$ 406,000	$ 414,000	$ 422,000	$ 431,000	$ 439,000	$ 448,000	$ 457,000	$ 466,000		
Weagamow (North Caribou Lake)													
	$ 120,000	$ 120,000											
	$ 459,000	$ 469,000	$ 478,000	$ 488,000	$ 497,000	$ 507,000	$ 517,000	$ 528,000	$ 538,000	$ 549,000	$ 560,000		
Wunnumin Lake													
			$ 120,000	$ 120,000									
	$ 479,000	$ 488,000	$ 498,000	$ 508,000	$ 518,000	$ 528,000	$ 539,000	$ 550,000	$ 561,000	$ 572,000	$ 583,000		
Fuel	$ 3,132,000	$ 3,287,000	$ 3,449,000	$ 3,620,000	$ 3,800,000	$ 3,988,000	$ 4,186,000	$ 4,393,000	$ 4,611,000	$ 4,838,000	$ 5,077,000		
Subtotal	$ 11,267,000	$ 11,807,000	$ 12,169,000	$ 12,256,000	$ 11,747,000	$ 12,091,000	$ 12,453,000	$ 12,831,000	$ 13,215,000	$ 13,614,000	$ 14,025,000		
Cumulative	$ 230,782,000	$ 242,589,000	$ 254,758,000	$ 267,014,000	$ 278,761,000	$ 290,852,000	$ 303,305,000	$ 316,136,000	$ 329,351,000	$ 342,965,000	$ 356,990,000		
Total	$ 11,267,000	$ 11,807,000	$ 12,169,000	$ 12,256,000	$ 11,747,000	$ 12,091,000	$ 12,453,000	$ 12,831,000	$ 13,215,000	$ 13,614,000	$ 14,025,000	GRAND TOTAL	$ 356,990,000.00

APPENDIX 4 – COST SUMMARY (OPERATION TO 2030)

Back Up Generation
Summary of Costs
2.7% Growth

OPERATION TO 2030

Year	Item	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Site		2	3	4	5	6	7	8	9	10	11	12
Bearskin Lake												
	Capital		$ 125,000									
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000
Deer Lake												
	Capital	$ 123,000										
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
Kasabonika Lake												
	Capital			$ 128,000								
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Keewaywin												
	Capital / IPA Initial		$ 478,000	$ 249,000								
	O&M				$ 249,000.00	$ 280,000.00	$ 286,000.00	$ 292,000.00	$ 298,000.00	$ 304,000.00	$ 310,000.00	$ 316,000.00
Kingfisher												
	Capital	$ 123,000										
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)												
	Capital			$ 128,000								
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Muskrat Dam												
	Capital / IPA Initial	$ 123,000	$ 119,000									
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
North Spirit Lake												
	Capital / IPA Initial			$ 128,000	$ 124,000		$ 538,000					
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Pikangikum												
	Capital / New Yard		$ 125,000	$ 3,700,000								
	O&M		$ 195,000	$ 211,000	$ 215,000	$ 220,000	$ 224,000	$ 228,000	$ 233,000	$ 238,000	$ 242,000	$ 247,000
Poplar Hill												
	Capital / IPA Initial	$ 123,000	$ 119,000									
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
Sachigo Lake												
	Capital		$ 125,000									
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000
Sandy Lake												
	Capital			$ 128,000								
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Wapekeka												
	Capital			$ 128,000								
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Wawakepewin												
	Capital / 300 kW Unit		$ 125,000	$ 487,000								
	O&M			$ 183,600	$ 202,709	$ 206,763	$ 210,899	$ 215,117	$ 219,419	$ 223,807	$ 228,284	$ 232,849
Weagamow (North Caribou Lake)												
	Capital	$ 123,000										
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
Wunnumin Lake												
	Capital / IPA Initial			$ 128,000	$ 124,000							
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Fuel			$ 664,000	$ 689,000	$ 716,000	$ 744,000	$ 775,000	$ 806,000	$ 839,000	$ 873,000	$ 908,000	$ 944,000
Subtotal		$ 615,000	$ 3,270,000	$ 8,071,000	$ 4,983,000	$ 5,026,000	$ 5,685,000	$ 5,265,000	$ 5,391,000	$ 5,512,000	$ 5,639,000	$ 5,769,000
Cumulative		$ 615,000	$ 3,885,000	$ 11,956,000	$ 16,939,000	$ 21,965,000	$ 27,650,000	$ 32,915,000	$ 38,306,000	$ 43,818,000	$ 49,457,000	$ 55,226,000
Total		$ 615,000	$ 3,270,000	$ 8,071,000	$ 4,983,000	$ 5,026,000	$ 5,685,000	$ 5,265,000	$ 5,391,000	$ 5,512,000	$ 5,639,000	$ 5,769,000

Grand Total $ 55,226,000

Index 0.02

Cost of Capital 0%

TOTAL	**$ 598,000**	IPA Initial Costs
TOTAL	**$ 1,016,000**	Capital - Transformers & Switchgear Upgrade (Weagamow and KI transformers only)
TOTAL	**$ -**	Capital Genset 2 MW Trailer Unit
TOTAL	**$ 4,187,000**	Capital 300 kW Unit Containerized Unit Wawakepewin, Pikangikum Site Development
TOTAL	**$ 2,001,000**	Capital Transitional Costs
TOTAL	**$ -**	Capital Sustainment Costs (10 yr cycle)

Notes: Capital for transitional costs are incurred one year before expect connection date
Yearly costs coincide with connection date year
Sustainment capital (10 yr period) spread over 2 years

Back Up Generation
Summary of Costs
4.0% Growth

OPERATION TO 2030

Year	Item	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Site		2	3	4	5	6	7	8	9	10	11	12
Bearskin Lake												
	Capital		$ 125,000									
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000
Deer Lake												
	Capital	$ 123,000										
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
Kasabonika Lake												
	Capital			$ 128,000					$ 571,000			
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Keewaywin												
	Capital / IPA Initial		$ 478,000	$ 249,000								
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Kingfisher												
	Capital	$ 123,000										
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)												
	Capital			$ 128,000								
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Muskrat Dam												
	Capital / IPA Initial	$ 123,000	$ 119,000									
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
North Spirit Lake												
	Capital / IPA Initial			$ 128,000	$ 652,000							
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Pikangikum												
	Capital / New Yard		$ 125,000	$ 3,700,000								
	O&M		$ 195,000	$ 211,000	$ 215,000	$ 220,000	$ 224,000	$ 228,000	$ 233,000	$ 238,000	$ 242,000	$ 247,000
Poplar Hill												
	Capital / IPA Initial	$ 123,000	$ 119,000									
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
Sachigo Lake												
	Capital		$ 125,000									
	O&M			$ 244,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 292,000	$ 297,000	$ 303,000	$ 309,000
Sandy Lake												
	Capital			$ 128,000								
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Wapekeka												
	Capital			$ 128,000								
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Wawakepewin												
	Capital / 300 kW Unit		$ 125,000	$ 487,000								
	O&M			$ 199,000	$ 220,000	$ 224,000	$ 229,000	$ 233,000	$ 238,000	$ 243,000	$ 247,000	$ 252,000
Weagamow (North Caribou Lake)												
	Capital	$ 123,000								$ 583,000		
	O&M		$ 239,000	$ 259,000	$ 264,000	$ 269,000	$ 275,000	$ 280,000	$ 286,000	$ 291,000	$ 297,000	$ 303,000
Wunnumin Lake												
	Capital / IPA Initial			$ 128,000	$ 124,000							
	O&M				$ 249,000	$ 280,000	$ 286,000	$ 292,000	$ 298,000	$ 304,000	$ 310,000	$ 316,000
Fuel			$ 687,000	$ 721,000	$ 758,000	$ 797,000	$ 839,000	$ 884,000	$ 931,000	$ 980,000	$ 1,031,000	$ 1,086,000
Subtotal		$ 615,000	$ 3,293,000	$ 8,118,000	$ 5,570,000	$ 5,096,000	$ 5,229,000	$ 5,361,000	$ 6,073,000	$ 6,221,000	$ 5,781,000	$ 5,930,000
Cumulative		$ 615,000	$ 3,908,000	$ 12,026,000	$ 17,596,000	$ 22,692,000	$ 27,921,000	$ 33,282,000	$ 39,355,000	$ 45,576,000	$ 51,357,000	$ 57,287,000
Total		$ 615,000	$ 3,293,000	$ 8,118,000	$ 5,570,000	$ 5,096,000	$ 5,229,000	$ 5,361,000	$ 6,073,000	$ 6,221,000	$ 5,781,000	$ 5,930,000

Grand Total $ 57,287,000.00

TOTAL	$ 1,126,000.00	IPA Initial Costs for Site Review and Operator Training
TOTAL	$ 2,160,000.00	Capital Transformers & Switchgear Upgrade (Weagamow and KI transformers only)
TOTAL		Capital Genset 2 MW trailer unit
TOTAL	$ 4,187,000.00	Capital 300 kW Unit Containerized Unit Wawakepewin, Pikangikum Site Development
TOTAL	$ 2,001,000.00	Capital Transitional Capital Costs
TOTAL	$ -	Capital Sustainment Costs (10 yr cycle)

Index 0.02

Cost of Capital 0%

Notes: Capital for transitional costs are incurred one year before expect connection date
Yearly costs coincide with connection date year
Sustainment capital (10 yr period) spread over 2 years

APPENDIX 5 – LOAD FORECAST

Peak Load Forecast (2.7% Growth)

Green boxes indicate when the DGS electrical limit is reached
Red boxes indicate when the DGS generation limit is reached

	Genset Prime Rating																
Community	G1	G2	G3	G4	Generation Capacity (kW)	Electrical Capacity (kW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bearskin Lake	619	410	1015		2044	1500	753	773	794	815	837	860	883	907	932	957	983
Deer Lake	1500	635	1280		3415	2000	1429	1467	1507	1548	1589	1632	1676	1722	1768	1816	1865
Kasabonika Lake	1125	1500	635		3260	1500	1176	1208	1241	1274	1309	1344	1380	1418	1456	1495	1535
Keewaywin	725	560	560		1845	750	769	790	811	833	856	879	902	927	952	977	1004
Kingfisher Lake	455	1045	725		2225	1500	704	723	743	763	783	804	826	848	871	895	919
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	635	1135	1100		2870	2250	1521	1562	1604	1647	1692	1738	1784	1833	1882	1933	1985
Muskrat Dam	410	545	725		1680		798	820	842	865	888	912	937	962	988	1015	1042
North Spirit Lake	725	545	545		1815	750	685	703	722	742	762	782	803	825	847	870	894
Pikanjikum	555	555	2000		3110		2344	2407	2472	2539	2608	2678	2750	2825	2901	2979	3060
Poplar Hill	725	545	910		2180	1250	885	909	933	959	984	1011	1038	1066	1095	1125	1155
Sachigo Lake	635	455	1250		2340	1250	815	837	859	882	906	931	956	982	1008	1035	1063
Sandy Lake	1250	1250	1500	1000	5000	4000	2876	2954	3033	3115	3199	3286	3374	3466	3559	3655	3754
Wapekeka	910	1045	410		2365	3000	680	699	717	737	757	777	798	820	842	865	888
Wawakepewin	125	125	50		300		168	172	177	182	187	192	197	202	208	213	219
Weagamow (North Caribou Lake)	635	725	455	1100	2915	1500	1121	1151	1182	1214	1247	1281	1315	1351	1387	1425	1463
Wunnumin Lake	1000	635	400		2035	1600	1079	1108	1138	1169	1200	1233	1266	1300	1335	1371	1408

Peak Load Forecast (4% Growth)

Green boxes indicate when the DGS electrical limit is reached
Red boxes indicate when the DGS generation limit is reached

	Genset Prime Rating																
Community	G1	G2	G3	G4	Generation Capacity (kW)	Electrical Capacity (kW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Bearskin Lake	619	410	1015		2044	1500	782	813	846	879	915	951	989	1029	1070	1113	1157
Deer Lake	1500	635	1280		3415	2000	1484	1543	1605	1669	1736	1805	1877	1952	2031	2112	2196
Kasabonika Lake	1125	1500	635		3260	1500	1222	1270	1321	1374	1429	1486	1546	1608	1672	1739	1808
Keewaywin	725	560	560		1845	750	799	831	864	898	934	972	1011	1051	1093	1137	1182
Kingfisher Lake	455	1045	725		2225	1500	731	760	791	822	855	890	925	962	1001	1041	1082
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	635	1135	1100		2870	2250	1579	1642	1708	1777	1848	1921	1998	2078	2161	2248	2338
Muskrat Dam	410	545	725		1680		829	862	897	933	970	1009	1049	1091	1135	1180	1227
North Spirit Lake	725	545	545		1815	750	711	739	769	800	832	865	900	936	973	1012	1052
Pikanjikum	555	555	2000		3110		2434	2532	2633	2738	2848	2962	3080	3203	3331	3465	3603
Poplar Hill	725	545	910		2180	1250	919	956	994	1034	1075	1118	1163	1209	1258	1308	1360
Sachigo Lake	635	455	1250		2340	1250	846	880	915	952	990	1029	1070	1113	1158	1204	1252
Sandy Lake	1250	1250	1500	1000	5000	4000	2987	3106	3230	3359	3494	3634	3779	3930	4087	4251	4421
Wapekeka	910	1045	410		2365	3000	706	735	764	795	826	859	894	930	967	1005	1046
Wawakepewin	125	125	50		300		174	181	189	196	204	212	221	229	239	248	258
Weagamow (North Caribou Lake)	635	725	455	1100	2915	1500	1164	1211	1259	1310	1362	1416	1473	1532	1593	1657	1723
Wunnumin Lake	1000	635	400		2035	1600	1120	1165	1212	1260	1311	1363	1418	1474	1533	1595	1658

Peak Load Forecast (2.7% Growth)

Community	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
Bearskin Lake	1009	1036	1064	1093	1123	1153	1184	1216	1249	1283	1317	1353	1389	1427	1465	1505	1546	1587
Deer Lake	1915	1967	2020	2075	2131	2188	2247	2308	2370	2434	2500	2567	2637	2708	2781	2856	2933	3013
Kasabonika Lake	1577	1620	1663	1708	1754	1802	1850	1900	1952	2004	2058	2114	2171	2230	2290	2352	2415	2480
Keewaywin	1031	1059	1087	1117	1147	1178	1210	1242	1276	1310	1346	1382	1419	1458	1497	1537	1579	1622
Kingfisher Lake	944	969	995	1022	1050	1078	1107	1137	1168	1200	1232	1265	1299	1334	1371	1408	1446	1485
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	2039	2094	2150	2208	2268	2329	2392	2457	2523	2591	2661	2733	2807	2882	2960	3040	3122	3207
Muskrat Dam	1070	1099	1129	1159	1191	1223	1256	1290	1324	1360	1397	1435	1473	1513	1554	1596	1639	1683
North Spirit Lake	918	942	968	994	1021	1048	1077	1106	1136	1166	1198	1230	1263	1298	1333	1369	1405	1443
Pikanjikum	3142	3227	3314	3404	3496	3590	3687	3786	3889	3994	4102	4212	4326	4443	4563	4686	4812	4942
Poplar Hill	1186	1218	1251	1285	1320	1355	1392	1430	1468	1508	1549	1590	1633	1677	1723	1769	1817	1866
Sachigo Lake	1092	1121	1152	1183	1215	1248	1281	1316	1351	1388	1425	1464	1503	1544	1586	1628	1672	1718
Sandy Lake	3855	3959	4066	4176	4289	4405	4523	4646	4771	4900	5032	5168	5308	5451	5598	5749	5904	6064
Wapekeka	912	937	962	988	1014	1042	1070	1099	1129	1159	1190	1222	1255	1289	1324	1360	1397	1434
Wawakepewin	225	231	237	244	250	257	264	271	279	286	294	302	310	318	327	336	345	354
Weagamow (North Caribou Lake)	1503	1543	1585	1628	1672	1717	1763	1811	1860	1910	1962	2015	2069	2125	2182	2241	2302	2364
Wunnumin Lake	1446	1485	1525	1567	1609	1652	1697	1743	1790	1838	1888	1939	1991	2045	2100	2157	2215	2275

Peak Load Forecast (4% Growth)

Community	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049
Bearskin Lake	1204	1252	1302	1354	1408	1464	1523	1584	1647	1713	1781	1853	1927	2004	2084	2167	2254	2344
Deer Lake	2284	2375	2470	2569	2672	2779	2890	3006	3126	3251	3381	3516	3657	3803	3955	4114	4278	4449
Kasabonika Lake	1881	1956	2034	2115	2200	2288	2380	2475	2574	2677	2784	2895	3011	3131	3257	3387	3522	3663
Keewaywin	1229	1279	1330	1383	1438	1496	1556	1618	1683	1750	1820	1893	1968	2047	2129	2214	2303	2395
Kingfisher Lake	1126	1171	1217	1266	1317	1369	1424	1481	1540	1602	1666	1733	1802	1874	1949	2027	2108	2193
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	2431	2529	2630	2735	2844	2958	3076	3199	3327	3460	3599	3743	3893	4048	4210	4379	4554	4736
Muskrat Dam	1276	1327	1380	1436	1493	1553	1615	1679	1747	1816	1889	1965	2043	2125	2210	2298	2390	2486
North Spirit Lake	1094	1138	1184	1231	1280	1332	1385	1440	1498	1558	1620	1685	1752	1822	1895	1971	2050	2132
Pikanjikum	3747	3897	4053	4215	4384	4559	4742	4931	5129	5334	5547	5769	6000	6240	6489	6749	7019	7299
Poplar Hill	1415	1471	1530	1591	1655	1721	1790	1862	1936	2014	2094	2178	2265	2356	2450	2548	2650	2756
Sachigo Lake	1302	1354	1408	1465	1523	1584	1648	1714	1782	1853	1928	2005	2085	2168	2255	2345	2439	2537
Sandy Lake	4598	4782	4973	5172	5379	5594	5817	6050	6292	6544	6806	7078	7361	7655	7962	8280	8611	8956
Wapekeka	1087	1131	1176	1223	1272	1323	1376	1431	1488	1548	1610	1674	1741	1811	1883	1959	2037	2118
Wawakepewin	268	279	290	302	314	327	340	353	367	382	397	413	430	447	465	483	503	523
Weagamow (North Caribou Lake)	1792	1864	1939	2016	2097	2181	2268	2359	2453	2551	2653	2759	2870	2984	3104	3228	3357	3491
Wunnumin Lake	1725	1794	1865	1940	2018	2098	2182	2270	2360	2455	2553	2655	2761	2872	2987	3106	3230	3360

Peak Load Forecast (2.7% Growth)

Community	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Bearskin Lake	1630	1674	1719	1766	1814	1862	1913	1964	2017	2072	2128	2185
Deer Lake	3094	3177	3263	3351	3442	3535	3630	3728	3829	3932	4038	4147
Kasabonika Lake	2547	2616	2687	2759	2834	2910	2989	3070	3152	3238	3325	3415
Keewaywin	1665	1710	1757	1804	1853	1903	1954	2007	2061	2117	2174	2232
Kingfisher Lake	1525	1566	1608	1652	1696	1742	1789	1837	1887	1938	1990	2044
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	3293	3382	3473	3567	3664	3762	3864	3968	4076	4186	4299	4415
Muskrat Dam	1729	1775	1823	1873	1923	1975	2028	2083	2139	2197	2256	2317
North Spirit Lake	1482	1522	1564	1606	1649	1694	1739	1786	1835	1884	1935	1987
Pikanjikum	5076	5213	5354	5498	5647	5799	5956	6117	6282	6451	6625	6804
Poplar Hill	1916	1968	2021	2076	2132	2189	2249	2309	2372	2436	2501	2569
Sachigo Lake	1764	1812	1860	1911	1962	2015	2070	2126	2183	2242	2302	2365
Sandy Lake	6228	6396	6568	6746	6928	7115	7307	7504	7707	7915	8129	8348
Wapekeka	1473	1513	1554	1596	1639	1683	1728	1775	1823	1872	1923	1975
Wawakepewin	364	373	383	394	404	415	427	438	450	462	475	487
Weagamow (North Caribou Lake)	2428	2493	2561	2630	2701	2774	2849	2925	3004	3086	3169	3254
Wunnumin Lake	2336	2399	2464	2531	2599	2669	2741	2815	2891	2969	3049	3132

Peak Load Forecast (4% Growth)

Community	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Bearskin Lake	2438	2536	2637	2743	2852	2966	3085	3208	3337	3470	3609	3753
Deer Lake	4627	4812	5005	5205	5413	5630	5855	6089	6333	6586	6849	7123
Kasabonika Lake	3810	3962	4121	4285	4457	4635	4821	5013	5214	5422	5639	5865
Keewaywin	2491	2590	2694	2802	2914	3030	3152	3278	3409	3545	3687	3834
Kingfisher Lake	2280	2371	2466	2565	2668	2774	2885	3001	3121	3245	3375	3510
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	4925	5122	5327	5540	5762	5992	6232	6481	6741	7010	7291	7582
Muskrat Dam	2585	2689	2796	2908	3025	3146	3271	3402	3538	3680	3827	3980
North Spirit Lake	2217	2306	2398	2494	2594	2697	2805	2918	3034	3156	3282	3413
Pikanjikum	7591	7895	8211	8539	8881	9236	9606	9990	10389	10805	11237	11687
Poplar Hill	2866	2981	3100	3224	3353	3487	3627	3772	3922	4079	4243	4412
Sachigo Lake	2638	2744	2853	2967	3086	3210	3338	3472	3610	3755	3905	4061
Sandy Lake	9314	9686	10074	10477	10896	11332	11785	12256	12747	13257	13787	14338
Wapekeka	2203	2291	2383	2478	2577	2680	2788	2899	3015	3136	3261	3392
Wawakepewin	544	565	588	612	636	662	688	716	744	774	805	837
Weagamow (North Caribou Lake)	3631	3776	3927	4084	4248	4417	4594	4778	4969	5168	5375	5590
Wunnumin Lake	3494	3634	3779	3930	4088	4251	4421	4598	4782	4973	5172	5379

APPENDIX 6 – FUEL FORECAST

Fuel Requirements with Contingency Fuel

Includes monthly testing fuel, fuel for BBA forecasted transmission outages (using an average load of 70% of peak load), 5-day January outage contingency fuel (using an average load of 85% of peak load)

Fuel Requirements (2.7% Growth)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Bearskin Lake	42,162	43,235	44,337	45,468	46,630	47,823	49,049	50,308	51,600	52,928	54,292	55,692	57,130	58,607	60,124	61,681	63,281	64,924	66,611	68,344	70,124
Deer Lake	65,807	67,518	69,275	71,080	72,934	74,837	76,792	78,800	80,862	82,980	85,154	87,388	89,682	92,038	94,457	96,942	99,494	102,114	104,806	107,570	110,409
Kasabonika Lake	66,963	68,705	70,495	72,333	74,220	76,158	78,149	80,193	82,293	84,449	86,664	88,938	91,274	93,673	96,136	98,666	101,265	103,933	106,674	109,488	112,379
Keewaywin	38,800	39,782	40,791	41,826	42,890	43,982	45,104	46,257	47,440	48,655	49,903	51,185	52,501	53,853	55,242	56,668	58,132	59,636	61,181	62,767	64,396
Kingfisher Lake	35,460	36,352	37,268	38,208	39,174	40,167	41,185	42,232	43,306	44,410	45,544	46,708	47,903	49,131	50,392	51,687	53,017	54,383	55,785	57,226	58,705
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	80,465	82,572	84,735	86,958	89,240	91,584	93,991	96,463	99,002	101,609	104,287	107,037	109,862	112,762	115,741	118,801	121,943	125,170	128,484	131,887	135,382
Muskrat Dam	42,222	43,296	44,400	45,533	46,697	47,892	49,120	50,380	51,675	53,004	54,370	55,772	57,213	58,692	60,211	61,771	63,373	65,018	66,708	68,444	70,226
North Spirit Lake	33,801	34,648	35,518	36,411	37,328	38,271	39,238	40,232	41,253	42,301	43,378	44,483	45,619	46,785	47,982	49,212	50,475	51,773	53,105	54,473	55,878
Pikanjikum	96,097	98,626	101,224	103,891	106,631	109,444	112,333	115,301	118,348	121,478	124,692	127,993	131,384	134,865	138,441	142,113	145,885	149,758	153,736	157,821	162,017
Poplar Hill	40,388	41,413	42,466	43,547	44,657	45,797	46,968	48,171	49,406	50,674	51,977	53,314	54,688	56,099	57,548	59,036	60,565	62,134	63,746	65,402	67,102
Sachigo Lake	45,421	46,581	47,773	48,998	50,255	51,546	52,873	54,234	55,633	57,070	58,545	60,060	61,616	63,214	64,855	66,541	68,272	70,049	71,875	73,750	75,676
Sandy Lake	139,244	142,916	146,687	150,560	154,538	158,623	162,818	167,127	171,551	176,096	180,763	185,556	190,479	195,534	200,726	206,058	211,534	217,158	222,934	228,866	234,958
Wapekeka	37,334	38,277	39,245	40,239	41,259	42,308	43,385	44,490	45,626	46,792	47,990	49,220	50,484	51,781	53,113	54,482	55,887	57,331	58,813	60,335	61,899
Wawakepewin	10,799	11,025	11,257	11,495	11,740	11,991	12,249	12,514	12,787	13,066	13,354	13,649	13,951	14,263	14,582	14,910	15,247	15,593	15,949	16,314	16,688
Weagamow (North Caribou Lake)	57,478	58,942	60,446	61,991	63,577	65,206	66,879	68,598	70,362	72,175	74,036	75,947	77,910	79,926	81,997	84,123	86,307	88,550	90,853	93,219	95,648
Wunnumin Lake	58,451	59,964	61,517	63,113	64,751	66,434	68,162	69,937	71,759	73,631	75,554	77,528	79,556	81,638	83,777	85,973	88,229	90,545	92,924	95,368	97,877

Fuel Requirements (4% Growth)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Bearskin Lake	43,690	45,340	47,057	48,842	50,698	52,629	54,637	56,725	58,897	61,156	63,505	65,948	68,489	71,131	73,879	76,737	79,709	82,800	86,015	89,359	92,836
Deer Lake	68,244	70,876	73,614	76,462	79,423	82,503	85,706	89,037	92,501	96,104	99,851	103,748	107,800	112,015	116,398	120,957	125,698	130,629	135,757	141,090	146,636
Kasabonika Lake	69,445	72,125	74,913	77,813	80,828	83,964	87,225	90,617	94,144	97,813	101,628	105,596	109,723	114,015	118,478	123,120	127,947	132,968	138,190	143,620	149,268
Keewaywin	40,199	41,710	43,281	44,915	46,614	48,381	50,220	52,131	54,119	56,187	58,337	60,573	62,899	65,318	67,833	70,449	73,170	76,000	78,943	82,003	85,186
Kingfisher Lake	36,730	38,102	39,529	41,013	42,557	44,162	45,831	47,567	49,372	51,250	53,203	55,234	57,346	59,543	61,827	64,203	66,674	69,244	71,916	74,696	77,586
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	83,466	86,707	90,078	93,584	97,230	101,022	104,966	109,067	113,333	117,769	122,383	127,181	132,171	137,360	142,757	148,371	154,208	160,279	166,593	173,160	179,989
Muskrat Dam	43,752	45,405	47,124	48,912	50,771	52,705	54,716	56,807	58,983	61,245	63,597	66,044	68,588	71,235	73,987	76,849	79,826	82,922	86,142	89,490	92,972
North Spirit Lake	35,007	36,310	37,665	39,075	40,541	42,065	43,650	45,299	47,014	48,797	50,652	52,581	54,587	56,673	58,843	61,100	63,446	65,887	68,425	71,065	73,811
Pikanjikum	99,700	103,590	107,637	111,845	116,222	120,773	125,507	130,430	135,550	140,875	146,413	152,172	158,162	164,391	170,869	177,607	184,614	191,901	199,480	207,362	215,560
Poplar Hill	41,848	43,425	45,065	46,770	48,544	50,388	52,307	54,302	56,377	58,534	60,779	63,113	65,540	68,064	70,690	73,420	76,260	79,213	82,284	85,478	88,800
Sachigo Lake	47,074	48,860	50,717	52,648	54,657	56,746	58,919	61,178	63,528	65,972	68,514	71,157	73,906	76,765	79,739	82,831	86,047	89,392	92,870	96,488	100,250
Sandy Lake	144,474	150,123	155,999	162,109	168,464	175,073	181,946	189,094	196,528	204,260	212,301	220,663	229,360	238,405	247,811	257,594	267,768	278,350	289,354	300,798	312,701
Wapekeka	38,677	40,127	41,634	43,203	44,834	46,530	48,294	50,128	52,036	54,020	56,084	58,230	60,462	62,783	65,198	67,708	70,319	73,035	75,859	78,796	81,851
Wawakepewin	11,121	11,468	11,830	12,206	12,597	13,003	13,426	13,866	14,324	14,799	15,294	15,809	16,344	16,900	17,479	18,081	18,707	19,358	20,036	20,740	21,472
Weagamow (North Caribou Lake)	59,564	61,817	64,160	66,597	69,131	71,766	74,508	77,358	80,323	83,406	86,613	89,948	93,416	97,023	100,775	104,676	108,733	112,953	117,342	121,906	126,652
Wunnumin Lake	60,606	62,933	65,353	67,870	70,487	73,210	76,041	78,985	82,047	85,232	88,544	91,989	95,571	99,297	103,171	107,201	111,392	115,750	120,283	124,997	129,900

Fuel Requirements with Contingency Fuel

Fuel Requirements (2.7% Growth)

	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Bearskin Lake	71,952	73,829	75,757	77,736	79,770	81,858	84,002	86,205	88,467	90,790	93,175	95,626	98,142	100,726	103,380	106,106	108,905	111,780	114,732	117,764
Deer Lake	113,324	116,318	119,393	122,551	125,795	129,125	132,546	136,059	139,667	143,373	147,178	151,086	155,100	159,222	163,456	167,803	172,268	176,854	181,563	186,400
Kasabonika Lake	115,348	118,396	121,527	124,743	128,045	131,437	134,920	138,497	142,171	145,944	149,819	153,799	157,886	162,083	166,394	170,821	175,367	180,036	184,832	189,757
Keewaywin	66,069	67,787	69,552	71,364	73,225	75,137	77,100	79,116	81,187	83,313	85,497	87,740	90,043	92,409	94,838	97,333	99,895	102,527	105,230	108,005
Kingfisher Lake	60,225	61,785	63,388	65,034	66,724	68,460	70,243	72,074	73,954	75,885	77,869	79,905	81,997	84,146	86,352	88,618	90,945	93,335	95,789	98,310
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	138,972	142,659	146,445	150,333	154,327	158,428	162,640	166,966	171,408	175,970	180,656	185,468	190,410	195,486	200,698	206,051	211,549	217,195	222,994	228,949
Muskrat Dam	72,057	73,937	75,867	77,850	79,887	81,978	84,126	86,331	88,597	90,923	93,313	95,766	98,286	100,875	103,533	106,262	109,066	111,945	114,902	117,939
North Spirit Lake	57,321	58,803	60,325	61,889	63,494	65,143	66,836	68,575	70,361	72,195	74,079	76,013	78,000	80,040	82,136	84,288	86,498	88,768	91,099	93,493
Pikanjikum	166,326	170,751	175,296	179,963	184,756	189,679	194,735	199,927	205,259	210,736	216,360	222,136	228,068	234,161	240,417	246,843	253,442	260,219	267,180	274,328
Poplar Hill	68,848	70,642	72,483	74,375	76,317	78,312	80,361	82,465	84,626	86,845	89,125	91,465	93,869	96,338	98,874	101,478	104,152	106,899	109,719	112,616
Sachigo Lake	77,653	79,685	81,770	83,913	86,113	88,372	90,692	93,076	95,523	98,036	100,618	103,269	105,992	108,788	111,659	114,609	117,637	120,748	123,943	127,223
Sandy Lake	241,214	247,639	254,238	261,015	267,975	275,123	282,464	290,003	297,745	305,697	313,863	322,250	330,863	339,709	348,794	358,124	367,706	377,546	387,652	398,032
Wapekeka	63,504	65,153	66,847	68,586	70,372	72,207	74,091	76,026	78,013	80,053	82,149	84,302	86,512	88,783	91,114	93,508	95,968	98,493	101,087	103,751
Wawakepewin	17,073	17,469	17,875	18,292	18,720	19,160	19,612	20,075	20,552	21,041	21,544	22,060	22,590	23,134	23,693	24,267	24,857	25,462	26,084	26,723
Weagamow (North Caribou Lake)	98,144	100,706	103,337	106,040	108,816	111,666	114,594	117,600	120,688	123,859	127,116	130,461	133,895	137,423	141,046	144,767	148,588	152,513	156,543	160,682
Wunnumin Lake	100,454	103,101	105,819	108,610	111,477	114,421	117,445	120,550	123,740	127,015	130,379	133,834	137,381	141,025	144,767	148,610	152,557	156,611	160,773	165,049

Fuel Requirements (4% Growth)

	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Bearskin Lake	96,452	100,213	104,124	108,192	112,423	116,822	121,398	126,157	131,106	136,253	141,606	147,173	152,962	158,984	165,246	171,758	178,532	185,576	192,901	200,520
Deer Lake	152,405	158,404	164,643	171,131	177,879	184,897	192,196	199,786	207,681	215,891	224,429	233,309	242,544	252,149	262,138	272,526	283,330	294,566	306,251	318,404
Kasabonika Lake	155,141	161,250	167,602	174,209	181,080	188,226	195,658	203,387	211,426	219,786	228,480	237,522	246,925	256,705	266,876	277,454	288,455	299,896	311,795	324,169
Keewaywin	88,496	91,939	95,519	99,243	103,115	107,143	111,331	115,687	120,218	124,929	129,829	134,925	140,225	145,737	151,469	157,430	163,630	170,078	176,784	183,759
Kingfisher Lake	80,593	83,719	86,971	90,352	93,869	97,527	101,331	105,287	109,401	113,680	118,130	122,758	127,571	132,576	137,782	143,196	148,827	154,683	160,773	167,107
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	187,091	194,478	202,160	210,149	218,458	227,099	236,086	245,432	255,152	265,261	275,774	286,708	298,079	309,905	322,204	334,995	348,297	362,132	376,520	391,484
Muskrat Dam	96,594	100,361	104,278	108,352	112,589	116,995	121,578	126,344	131,300	136,455	141,816	147,391	153,190	159,220	165,492	172,014	178,798	185,852	193,189	200,820
North Spirit Lake	76,666	79,635	82,723	85,935	89,275	92,749	96,362	100,119	104,027	108,091	112,317	116,713	121,284	126,038	130,982	136,124	141,472	147,034	152,818	158,834
Pikanjikum	224,085	232,951	242,172	251,761	261,735	272,107	282,894	294,113	305,780	317,914	330,533	343,657	357,306	371,501	386,264	401,618	417,585	434,191	451,462	469,423
Poplar Hill	92,255	95,848	99,585	103,471	107,513	111,716	116,087	120,634	125,362	130,279	135,393	140,712	146,243	151,995	157,978	164,200	170,671	177,400	184,399	191,678
Sachigo Lake	104,163	108,233	112,465	116,866	121,444	126,204	131,155	136,304	141,659	147,228	153,020	159,044	165,308	171,823	178,599	185,646	192,974	200,596	208,523	216,767
Sandy Lake	325,079	337,953	351,341	365,265	379,746	394,807	410,469	426,758	443,699	461,318	479,641	498,697	518,515	539,126	560,561	582,854	606,039	630,151	655,227	681,307
Wapekeka	85,028	88,332	91,768	95,341	99,058	102,923	106,943	111,123	115,471	119,992	124,695	129,586	134,672	139,961	145,463	151,184	157,134	163,322	169,758	176,451
Wawakepewin	22,234	23,026	23,850	24,707	25,598	26,524	27,488	28,491	29,533	30,617	31,745	32,917	34,137	35,405	36,724	38,096	39,522	41,006	42,549	44,154
Weagamow (North Caribou Lake)	131,589	136,723	142,062	147,615	153,390	159,396	165,642	172,138	178,894	185,920	193,228	200,827	208,731	216,950	225,499	234,389	243,635	253,251	263,251	273,652
Wunnumin Lake	134,999	140,302	145,817	151,552	157,517	163,720	170,172	176,882	183,860	191,117	198,664	206,514	214,677	223,167	231,996	241,179	250,729	260,661	270,990	281,733

Fuel Requirements without Contingency Fuel

Includes monthly testing fuel and fuel for BBA forecasted transmission outages (using an average load of 70% of peak load)

Does not include contingency fuel for 5-day January outage

Fuel Requirements (2.7% Growth)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Bearskin Lake	21,408	21,921	22,447	22,988	23,543	24,113	24,698	25,299	25,917	26,551	27,202	27,871	28,558	29,263	29,988	30,732	31,496	32,281	33,087	33,915	34,765
Deer Lake	26,419	27,067	27,732	28,416	29,117	29,838	30,578	31,338	32,118	32,920	33,743	34,588	35,457	36,348	37,264	38,205	39,171	40,163	41,182	42,228	43,302
Kasabonika Lake	34,534	35,400	36,291	37,205	38,144	39,108	40,098	41,115	42,160	43,233	44,334	45,466	46,628	47,821	49,046	50,305	51,598	52,925	54,289	55,689	57,127
Keewaywin	17,598	18,008	18,429	18,861	19,304	19,760	20,228	20,708	21,202	21,709	22,229	22,764	23,313	23,877	24,456	25,050	25,661	26,288	26,932	27,594	28,273
Kingfisher Lake	16,050	16,418	16,796	17,184	17,582	17,991	18,411	18,843	19,286	19,741	20,208	20,688	21,181	21,688	22,207	22,741	23,290	23,853	24,432	25,026	25,636
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	38,539	39,514	40,515	41,544	42,600	43,684	44,798	45,942	47,117	48,324	49,563	50,835	52,142	53,485	54,863	56,279	57,733	59,226	60,759	62,334	63,952
Muskrat Dam	20,214	20,694	21,188	21,694	22,214	22,748	23,297	23,860	24,439	25,033	25,643	26,270	26,914	27,575	28,254	28,951	29,667	30,403	31,158	31,934	32,730
North Spirit Lake	14,928	15,266	15,612	15,968	16,334	16,709	17,095	17,491	17,897	18,315	18,744	19,184	19,637	20,101	20,578	21,068	21,572	22,088	22,619	23,164	23,724
Pikanjikum	31,477	32,262	33,067	33,894	34,744	35,616	36,512	37,433	38,378	39,348	40,345	41,369	42,420	43,500	44,609	45,747	46,917	48,118	49,352	50,619	51,920
Poplar Hill	15,992	16,358	16,734	17,120	17,517	17,924	18,342	18,772	19,213	19,666	20,132	20,610	21,101	21,605	22,123	22,654	23,200	23,761	24,337	24,928	25,536
Sachigo Lake	22,965	23,519	24,089	24,674	25,274	25,891	26,524	27,175	27,843	28,529	29,234	29,958	30,701	31,464	32,248	33,053	33,880	34,729	35,601	36,497	37,417
Sandy Lake	59,962	61,493	63,066	64,681	66,340	68,044	69,793	71,590	73,436	75,331	77,278	79,277	81,330	83,438	85,603	87,827	90,111	92,457	94,865	97,339	99,880
Wapekeka	18,581	19,018	19,465	19,925	20,398	20,883	21,381	21,893	22,418	22,958	23,512	24,081	24,666	25,266	25,883	26,516	27,166	27,834	28,520	29,225	29,948
Wawakepewin	6,170	6,271	6,375	6,481	6,591	6,703	6,819	6,937	7,059	7,184	7,312	7,444	7,579	7,718	7,861	8,008	8,158	8,313	8,472	8,635	8,802
Weagamow (North Caribou Lake)	26,571	27,201	27,848	28,513	29,195	29,896	30,616	31,355	32,114	32,893	33,694	34,516	35,361	36,228	37,119	38,033	38,973	39,938	40,928	41,946	42,991
Wunnumin Lake	28,709	29,419	30,148	30,896	31,665	32,454	33,264	34,097	34,952	35,830	36,732	37,658	38,609	39,586	40,589	41,620	42,678	43,764	44,880	46,027	47,204

Fuel Requirements (4% Growth)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Bearskin Lake	22,138	22,927	23,746	24,599	25,486	26,408	27,367	28,365	29,402	30,481	31,603	32,770	33,984	35,246	36,558	37,923	39,343	40,820	42,355	43,952	45,613
Deer Lake	27,342	28,339	29,375	30,453	31,574	32,739	33,952	35,213	36,524	37,888	39,306	40,781	42,315	43,910	45,570	47,295	49,090	50,956	52,897	54,916	57,015
Kasabonika Lake	35,768	37,102	38,489	39,931	41,431	42,991	44,613	46,301	48,056	49,881	51,779	53,753	55,806	57,941	60,161	62,470	64,872	67,369	69,967	72,669	75,478
Keewaywin	18,182	18,812	19,467	20,149	20,857	21,594	22,361	23,158	23,987	24,850	25,747	26,679	27,649	28,658	29,707	30,798	31,933	33,113	34,340	35,617	36,944
Kingfisher Lake	16,574	17,140	17,728	18,340	18,977	19,638	20,327	21,043	21,787	22,561	23,367	24,204	25,075	25,981	26,923	27,903	28,921	29,981	31,083	32,229	33,421
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	39,928	41,428	42,988	44,610	46,297	48,052	49,877	51,775	53,748	55,801	57,936	60,156	62,465	64,867	67,364	69,962	72,663	75,472	78,394	81,432	84,593
Muskrat Dam	20,898	21,637	22,405	23,204	24,035	24,899	25,798	26,733	27,705	28,716	29,767	30,861	31,998	33,181	34,411	35,690	37,021	38,404	39,843	41,340	42,896
North Spirit Lake	15,409	15,928	16,468	17,030	17,614	18,221	18,853	19,509	20,193	20,903	21,642	22,411	23,210	24,041	24,905	25,804	26,739	27,712	28,723	29,775	30,869
Pikanjikum	32,594	33,801	35,056	36,361	37,718	39,130	40,598	42,124	43,712	45,363	47,081	48,867	50,724	52,656	54,665	56,754	58,927	61,187	63,538	65,982	68,524
Poplar Hill	16,513	17,077	17,662	18,272	18,905	19,564	20,250	20,963	21,704	22,475	23,277	24,111	24,978	25,880	26,818	27,793	28,808	29,863	30,960	32,101	33,288
Sachigo Lake	23,755	24,608	25,495	26,417	27,377	28,375	29,412	30,492	31,614	32,782	33,996	35,258	36,571	37,937	39,357	40,834	42,371	43,968	45,630	47,358	49,155
Sandy Lake	62,143	64,499	66,949	69,498	72,148	74,904	77,771	80,752	83,853	87,077	90,431	93,918	97,545	101,318	105,241	109,321	113,564	117,977	122,567	127,340	132,304
Wapekeka	19,203	19,873	20,571	21,297	22,052	22,836	23,653	24,502	25,384	26,303	27,258	28,251	29,283	30,358	31,475	32,636	33,845	35,101	36,408	37,767	39,181
Wawakepewin	6,314	6,469	6,631	6,799	6,974	7,156	7,345	7,541	7,746	7,958	8,179	8,409	8,649	8,897	9,156	9,425	9,705	9,996	10,298	10,613	10,941
Weagamow (North Caribou Lake)	27,469	28,438	29,446	30,494	31,584	32,718	33,897	35,123	36,399	37,725	39,104	40,539	42,031	43,582	45,196	46,874	48,620	50,435	52,323	54,286	56,328
Wunnumin Lake	29,720	30,812	31,947	33,127	34,355	35,632	36,961	38,342	39,778	41,272	42,826	44,442	46,122	47,870	49,687	51,578	53,544	55,588	57,714	59,926	62,226

Fuel Requirements without Contingency Fuel

Fuel Requirements (2.7% Growth)

	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Bearskin Lake	35,638	36,534	37,455	38,401	39,372	40,369	41,394	42,446	43,526	44,636	45,775	46,946	48,148	49,382	50,650	51,952	53,289	54,662	56,072	57,521
Deer Lake	44,406	45,539	46,703	47,899	49,126	50,387	51,682	53,012	54,377	55,780	57,220	58,700	60,219	61,779	63,382	65,027	66,718	68,453	70,236	72,067
Kasabonika Lake	58,604	60,120	61,678	63,278	64,921	66,608	68,341	70,120	71,948	73,825	75,752	77,732	79,765	81,853	83,998	86,200	88,462	90,785	93,170	95,620
Keewaywin	28,971	29,688	30,424	31,180	31,956	32,753	33,572	34,413	35,276	36,163	37,074	38,009	38,970	39,956	40,970	42,010	43,079	44,176	45,304	46,461
Kingfisher Lake	26,262	26,906	27,566	28,245	28,942	29,658	30,393	31,148	31,924	32,720	33,538	34,378	35,240	36,126	37,036	37,970	38,930	39,915	40,927	41,967
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	65,613	67,319	69,071	70,870	72,718	74,616	76,565	78,566	80,622	82,733	84,901	87,128	89,415	91,763	94,175	96,652	99,196	101,809	104,492	107,248
Muskrat Dam	33,548	34,388	35,251	36,138	37,048	37,982	38,942	39,928	40,940	41,980	43,048	44,145	45,271	46,428	47,616	48,836	50,089	51,376	52,697	54,054
North Spirit Lake	24,299	24,890	25,496	26,119	26,758	27,415	28,090	28,783	29,494	30,225	30,975	31,746	32,538	33,351	34,185	35,043	35,923	36,828	37,756	38,710
Pikanjikum	53,256	54,628	56,038	57,485	58,971	60,498	62,066	63,676	65,330	67,028	68,772	70,563	72,403	74,292	76,233	78,225	80,272	82,373	84,532	86,749
Poplar Hill	26,160	26,801	27,459	28,134	28,828	29,541	30,273	31,025	31,797	32,590	33,404	34,240	35,099	35,981	36,887	37,818	38,773	39,754	40,762	41,797
Sachigo Lake	38,361	39,331	40,328	41,351	42,402	43,481	44,589	45,728	46,897	48,097	49,330	50,597	51,897	53,233	54,604	56,013	57,460	58,946	60,472	62,039
Sandy Lake	102,489	105,169	107,921	110,748	113,650	116,631	119,693	122,837	126,066	129,383	132,788	136,286	139,878	143,568	147,357	151,248	155,244	159,348	163,563	167,892
Wapekeka	30,691	31,454	32,238	33,043	33,869	34,718	35,590	36,485	37,405	38,349	39,319	40,315	41,338	42,388	43,467	44,575	45,713	46,882	48,082	49,314
Wawakepewin	8,975	9,151	9,333	9,519	9,711	9,907	10,109	10,316	10,529	10,748	10,972	11,203	11,440	11,683	11,933	12,190	12,453	12,724	13,002	13,287
Weagamow (North Caribou Lake)	44,064	45,167	46,299	47,461	48,655	49,881	51,141	52,434	53,762	55,126	56,527	57,966	59,444	60,961	62,520	64,120	65,764	67,452	69,186	70,966
Wunnumin Lake	48,413	49,654	50,929	52,239	53,583	54,965	56,383	57,840	59,336	60,872	62,450	64,071	65,735	67,444	69,200	71,003	72,854	74,755	76,708	78,714

Fuel Requirements (4% Growth)

	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061
Bearskin Lake	47,341	49,137	51,005	52,948	54,969	57,071	59,256	61,529	63,893	66,352	68,909	71,568	74,333	77,209	80,201	83,311	86,547	89,911	93,411	97,050
Deer Lake	59,199	61,470	63,831	66,287	68,841	71,498	74,261	77,134	80,122	83,230	86,462	89,823	93,319	96,954	100,735	104,667	108,757	113,010	117,433	122,033
Kasabonika Lake	78,400	81,439	84,599	87,886	91,304	94,859	98,556	102,401	106,400	110,559	114,884	119,382	124,060	128,926	133,985	139,248	144,720	150,412	156,331	162,487
Keewaywin	38,325	39,761	41,254	42,807	44,422	46,101	47,848	49,665	51,554	53,519	55,563	57,688	59,899	62,197	64,588	67,074	69,660	72,349	75,146	78,055
Kingfisher Lake	34,661	35,950	37,291	38,685	40,136	41,644	43,212	44,844	46,540	48,305	50,140	52,048	54,033	56,097	58,244	60,476	62,798	65,213	67,724	70,336
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	87,879	91,297	94,852	98,549	102,393	106,392	110,550	114,875	119,373	124,051	128,915	133,975	139,237	144,709	150,400	156,319	162,474	168,876	175,534	182,458
Muskrat Dam	44,515	46,198	47,949	49,770	51,663	53,633	55,681	57,811	60,026	62,330	64,726	67,218	69,809	72,504	75,307	78,222	81,254	84,407	87,686	91,096
North Spirit Lake	32,006	33,189	34,420	35,699	37,030	38,414	39,853	41,350	42,907	44,526	46,210	47,961	49,782	51,676	53,646	55,695	57,825	60,041	62,346	64,742
Pikanjikum	71,168	73,917	76,777	79,751	82,843	86,060	89,405	92,884	96,502	100,265	104,179	108,249	112,481	116,883	121,461	126,223	131,174	136,324	141,680	147,250
Poplar Hill	34,522	35,806	37,141	38,530	39,974	41,475	43,037	44,662	46,351	48,108	49,935	51,835	53,811	55,866	58,004	60,227	62,539	64,943	67,444	70,044
Sachigo Lake	51,024	52,968	54,989	57,091	59,278	61,552	63,917	66,376	68,934	71,594	74,361	77,238	80,230	83,342	86,579	89,945	93,445	97,086	100,872	104,810
Sandy Lake	137,466	142,835	148,419	154,226	160,266	166,547	173,079	179,872	186,938	194,286	201,927	209,875	218,140	226,736	235,676	244,974	254,643	264,699	275,157	286,034
Wapekeka	40,651	42,180	43,770	45,423	47,143	48,931	50,792	52,726	54,738	56,830	59,006	61,269	63,623	66,070	68,616	71,264	74,017	76,880	79,858	82,955
Wawakepewin	11,281	11,635	12,003	12,386	12,784	13,199	13,629	14,077	14,543	15,028	15,532	16,056	16,601	17,167	17,757	18,370	19,008	19,671	20,360	21,078
Weagamow (North Caribou Lake)	58,451	60,660	62,957	65,345	67,830	70,413	73,100	75,895	78,801	81,823	84,966	88,236	91,635	95,171	98,848	102,673	106,650	110,786	115,088	119,562
Wunnumin Lake	64,617	67,105	69,692	72,382	75,181	78,091	81,117	84,264	87,538	90,942	94,483	98,165	101,994	105,977	110,119	114,426	118,906	123,565	128,410	133,450

APPENDIX 7 – COMMUNITY ENGAGEMENT FEEDBACK

The following is a summary from OSLP of backup power comments, feedback, and themes taken from various community engagement initiatives.

1. Backup Power should be community-wide (i.e. full backup).
2. In the case where full backup capacity is not available, load shedding should be considered.
3. Full Backup Power for communities would decrease the potential for evacuation, especially during the winter months.
    a) Costs associated with community evacuation are very high.
    b) Avoiding even one community evacuation could justify the costs associated with Backup Power for a whole year.
4. Response time for Backup Power should be 2-4 hours maximum since that is how long the batteries for communications equipment and most home-based medical equipment last.
5. Extended outages during the winter increase the use of wood stoves and other alternative means to heating which pose health & safety risks.
    a) There have been instances where houses have burnt down due to increased wood heating as a result of extended outages.
    b) There have been deaths of elderly people resulting from inadequate heating during extended outages in the winter months (i.e. pneumonia).
    c) Water piping infrastructure is at risk of freezing during outages occurring in winter months. Costs associated with frozen / burst pipes are high.
6. Extended outages pose significant health & safety risks to people reliant on medical equipment (i.e. home dialysis machines, sleep apnea machines, medical fluids that must be kept at constant temperature, etc.)
7. Extended outages during the summer make keeping food frozen and/or refrigerated difficult which pose health & safety risks.
8. Extended outages impact community services including shutdown of schools.
9. Due to the length of transmission line and remoteness of communities, there is a greater need for backup power than in non-remote communities.
10. Communities located the furthest north have additional logistical challenges that increase risks associated with extended outages.
11. Ice storms increase the potential for extended outages in the winter and fires increase the potential for extended outages in the summer.
12. Transportation is a risk for many elderly people during extended outages, especially in winter months.
13. Backup Power solutions must not financially burden the communities.

In many First Nations, some critical assets are not currently connected to backup power sources or the backup power sources that they are connected to require maintenance / upgrades.

Appendix E

Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities Containerized DGS Option Annex

FEASIBILITY OF USING EXISTING DIESEL GENERATING STATIONS FOR BACKUP POWER IN REMOTE GRID-CONNECTED COMMUNITIES

CONTAINERIZED DGS OPTION ANNEX

NOVEMBER 2019

PREPARED FOR:

PREPARED BY:

REMOTE COMMUNITIES INC.

TABLE OF CONTENTS

1 INTRODUCTION

This report is an Annex to the December 2018 report "Feasibility Of Using Existing Diesel Generation Stations For Backup Power In Remote Grid-Connected Communities". One option for backup power that was discussed was for Hydro One Remote Communities Inc. (Remotes) to own and operate backup generating facilities in IPA First Nations by constructing the assets on greenfield sites. This Annex looks at the detailed cost to build such a station in six IPA communities (Keewaywin, Muskrat Dam, North Spirit Lake, Poplar Hill, Wawakapewin, Wunnumin Lake) plus Pikangikum and Weagamow. Pikangikum is included as its diesel generating station has reached its end of life and will be decommissioned. Weagamow is included as its station is at end of life and the site has significant contamination that requires cleanup. Hydro One will not operate on the existing site after grid connection and the First Nation has stated they want the site remediated.

2 DESIGN CONSIDERATIONS

A decision was made to size the generating stations to supply full community backup until 2030 as a minimum, using a 4% load growth per year (similar to 2018 report). This would give ample time to assess the need for backup power after seeing the reliability of the transmission system for a few years. If full community backup is still required beyond 2030, additional capital investment will be required.

A configuration summary is given in Appendix 1, showing the selected sizes for the gensets, transformers, and fuel tanks for each of the stations. The year that demand is expected to surpass the capacity of each piece of equipment is also given. Community summary sheets (Appendix 2) detail expected backup power demand, fuel usage, and fuel storage requirements for each community until 2061.

The following sub-sections detail equipment selection.

2.1 GENSETS

An effort was made to standardize on two or three genset sizes appropriate for all the communities, minus Wawakapewin which is much smaller than the others. A 300kW unit was chosen for Wawakapewin. 1400kW units will be suitable for Keewaywin, Muskrat Dam, North Spirit Lake, and Poplar Hill. 2000kW units are suitable for Pikangikum, Weagamow, and Wunnumin, but Pikangikum requires two units for a total of 4000kW.

Since genset sizes are set by the manufacturers, a genset sized perfectly for the load in 2030 was not possible. The next largest size was selected and therefore it is expected that in most communities, the genset will provide full community backup for a few years beyond 2030.

Gensets would be housed in standard containers provided by the genset manufacturers with some additional options (spill containment, level 2 soundproofing, day tank, lighting, heating). Genset prices in this report were obtained from Cummins and Caterpillar and reflect the cost with the options.

The 2000kW genset packages will be heavier than the winter road weight limit. Therefore the alternator portion would be shipped separately and assembled at site. Costs have been included for that work for the communities that would use that size genset.

2.2 FUEL STORAGE & HANDLING

All winter road access sites will have fuel supply sufficient for monthly testing, previously estimated transmission system outages, and a 5 day major outage occurring in January before the winter road opens. Fuel requirements are based on an average efficiency of 3.8 kWh/L. The community summary sheets (Appendix 2) show the expected fuel required (ie. without a major outage) and the fuel storage required (ie. with a major outage).

Fuel will be delivered via an offload kiosk with spill containment. The kiosk will house a fuel meter, tank level display, and controls for the tank automation.

An 80,000L tank designed for Ontario regulations is sufficient for all winter road sites except for Wunnumin. Wawakapewin requires much less fuel than the others but a 50,000L tank was chosen to use standard parts (level measuring devices, submersible pump) and to avoid having to reprogram the controls and SCADA for a smaller tank. Weagamow currently has an all season road so one fuel tank is sufficient. It was assumed that Pikangikum will also have an all season road in the near future, so it was also planned with one tank.

Consideration was given to reusing fuel tanks from existing IPA stations. Unfortunately all but four of the tanks are of a vintage that will not meet modern fuel codes. The four that will meet code do not have appropriate catwalks required for safety when servicing the tank. In Remotes' experience, the cost to move a tank to a new location, clean it, inspect it, recertify it, and add appropriate catwalks is more expensive than installing a new, clean, certified tank.

2.3 TRANSFORMERS

One three-phase pad-mount transformer is required for each site. Prime power stations have a spare transformer at site because they are not off-the-shelf equipment so replacements have long lead times. In the interest of saving money, a decision was made to purchase one spare transformer that would be delivered to any of the sites in the event of a failure. The cost of that spare transformer was split equally among the new stations.

Transformer costs in this size range increase minimally with increase in rating. 3000kVA transformers were selected for all communities other than Pikangikum (4000kVA) and Wawakapewin (500kVA). All transformers would adhere to the same specification. The transformers were oversized so that they would be suitable beyond 2040. The cost difference between a transformer sized for 2030 and one sized for beyond 2040 is around $10-15k. However a transformer upgrade in 2030 to extend the life of the backup station would be in the $450,000 range per site.

Transformers typically last forty years or more, so these transformers would reach end of life because demand would surpass their capacity, not because they are too old.

2.4 SITE SELECTION & DEVELOPMENT

New greenfield sites in each of the communities were proposed by the Backup Power Working Group in collaboration with the IPA Transfer Project Team (First Nation and Tribal Council). The sites were sized to contain both the backup generating equipment and the distribution requirements (distribution equipment, house, garage) being installed as part of the IPA transfer project to allow Remotes to operate the distribution systems in the IPA communities. Site development costs (tree clearing, site leveling, aggregate, grading, fencing) were proportioned between the IPA transfer project and the backup station project based on the size requirements of each. Costs in this report assume that the two projects will use a shared site. If the sites are not shared, costs will be higher. Also, if the IPA transfer yard is developed first, and the backup power yard is added later, costs will be higher. Appendix 3 shows a potential site layout based on the new site proposed for Wunnumin.

3 ENGINEERING DESIGN

Engineering design costs were estimated based on Remotes developing design standards for backup generating stations. Those standards would be used by an engineering consultant hired by the First Nation to design the generating station for their community. The consultant would include Remotes in their design review to ensure the design properly meets Remotes' standards. The consultant would create a tender package with construction drawings and specification and also serve as the project manager during construction.

4 CONSTRUCTION

The First Nation would hire a contractor for site development and construction of the backup power station. Use of local resources would be maximized during site development. During assembly of the backup generating equipment, the contractor would have their own forces on site but supplement that with local labour and use local heavy equipment. Such an arrangement would provide significant economic benefit to the community.

High level details of the construction steps are shown in the schedule in Appendix 7.

5 COSTS

A large number of assumptions were required to estimate the costs to install new backup generating stations (see Appendix 5). The majority of costs are the same for each community but there are differences when the generating capacity or fuel storage requirements differ.

The costs for a new backup generating station at each site and the total for all eight communities is given here. A summary of the costs for each phase of the project for each site is included in Appendix 4.

Keewaywin	$3,568,400
Muskrat Dam	$3,568,400
North Spirit Lake	$3,568,400
Pikangikum	$5,848,700
Poplar Hill	$3,568,400
Wawakapewin	$2,901,800
Weagamow	$3,903,900
Wunnumin Lake	$4,299,900
Total	**$31,227,900**

Appendix 6 has an updated table from the 2018 report showing the total costs to install and operate backup generation in all grid connected remote communities until 2030. That table uses current year (unescalated) costs. Escalated totals (2% per year) are given at the bottom of the table. A summary of O&M, Capital, and Total costs to 2030 from that table is given here.

COSTS TO 2030	Current Year (Unescalated)	Escalated
Total O&M	$32,639,000	$37,621,000
Total Capital	$32,969,900	$34,684,000
Total Backup Costs	**$65,608,900**	**$72,305,000**

6 TIMELINE

Appendix 7 gives a typical project schedule if the first backup station was to be constructed in 2021. The winter road is a time constraint. The genset is the longest lead item. It would require testing in December 2020 to be ready for the 2021 winter road. The genset procurement must happen about 26 weeks before testing. The common backup design is required before the first genset procurement. The schedule shows that the design would have to start in January 2020 for the first new backup station to be built in 2021.

Construction could start in the spring of 2021 and would take about four months from site preparation until completion.

7 CONCLUSION

The costs and logistics for installing new stations in the IPA communities were investigated using a number of assumptions. The first transmission system connections (other than Pikangikum) were assumed to occur in 2021 although the transmission system construction schedule will determine the actual connection dates. In order for the first backup stations to be installed in 2021, design work must commence very early in 2020.

Other options for backup power in the IPA communities are being considered separately. This report concludes that new backup generating stations are a suitable option for Remotes to provide backup power in IPA communities, and should be considered among the backup power options.

APPENDIX 1 – CONFIGURATION SUMMARY

Configuration Summary

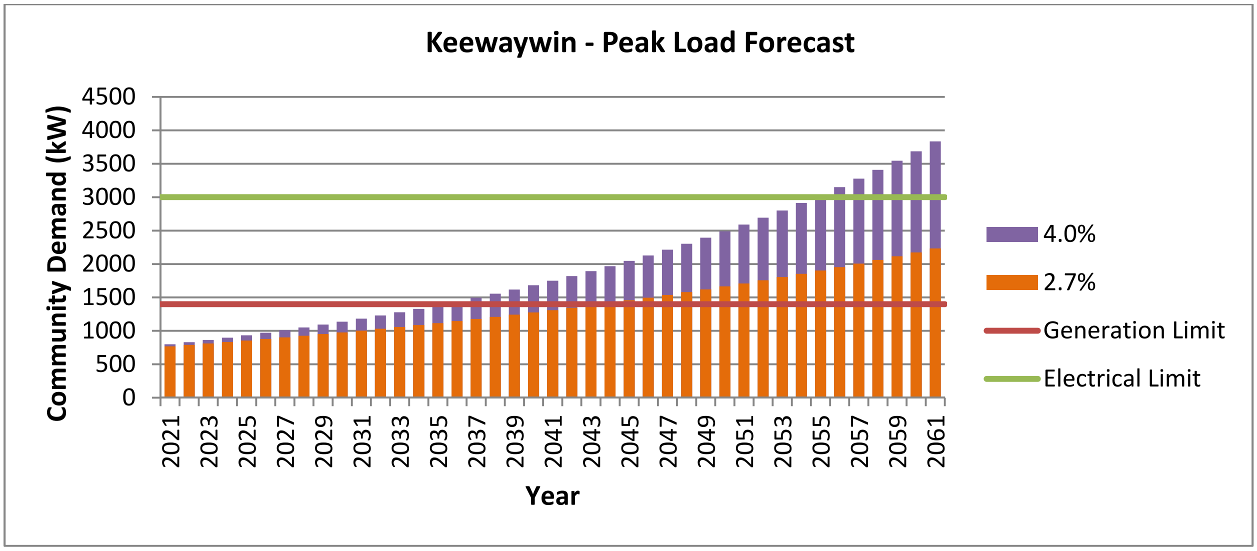
	Keewaywin	Muskrat Dam	North Spirit Lake	Pikangikum	Poplar Hill	Wawakepewin	Weagamow	Wunnumin Lake
Genset (kW)	1,400	1,400	1,400	2,000x2	1,400	300	2,000	2,000
Year Capacity Exceeded	2036	2035	2039	2034	2032	2035	2035	2036
Bulk Fuel Tank (L)	80,000	80,000	80,000	80,000	80,000	50,000	80,000	50,000x2
Year Capacity Exceeded	2036	2034	2040	N/A	2035	2061	N/A	2030
Transformer (kVA)	3,000	3,000	3,000	5,000	3,000	500	3,000	3,000
Year Capacity Exceeded	2055	2054	2058	2040	2052	2048	2046	2047

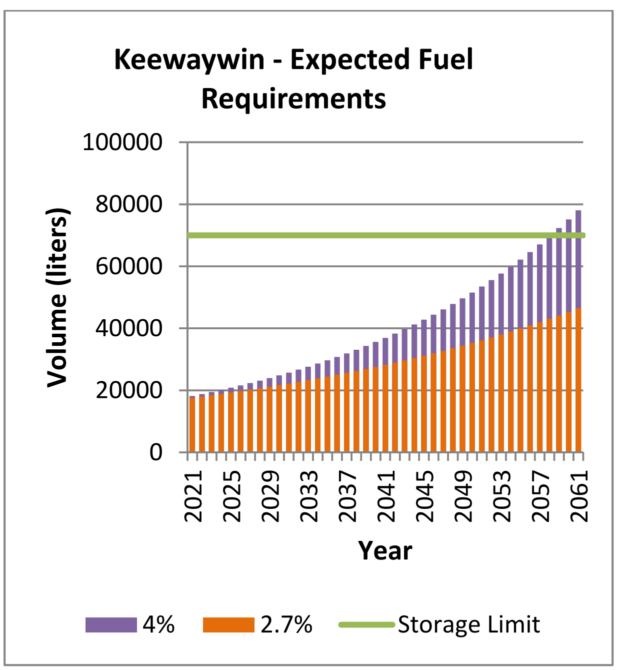
Highlighted stations are identical other than differences in site layout

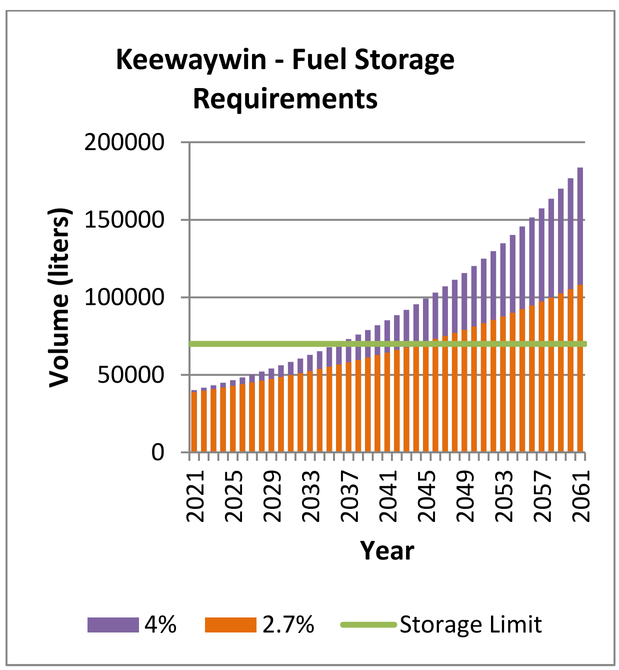
APPENDIX 2 – COMMUNITY SUMMARY SHEETS

Keewaywin DGS Summary

Proposed Configuration	
Genset Rating (kW)	1400
Number of 80,000L fuel tanks	1
Transformer Rating (kVA)	3000
2030 Peak Demand (kW)	1137
2030 Fuel requirement without major outage (L)	25000
2030 Fuel requirement with major outage (L)	56000
Year additional generation required for full community backup	2036
Year additional fuel storage required with major outage	2036
Year additional transformation capacity required	2055

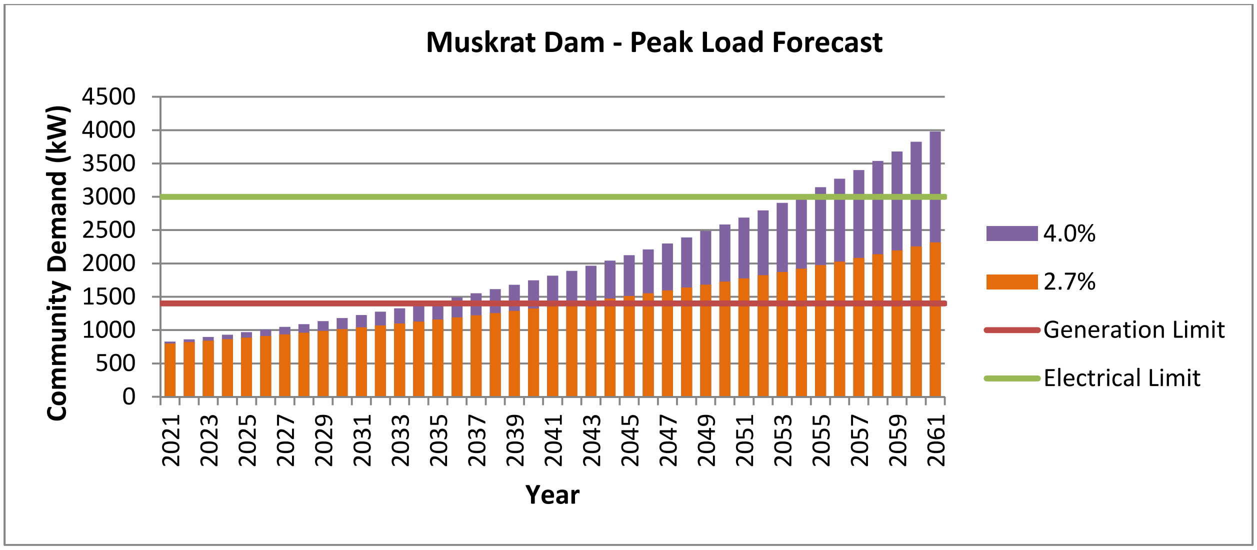


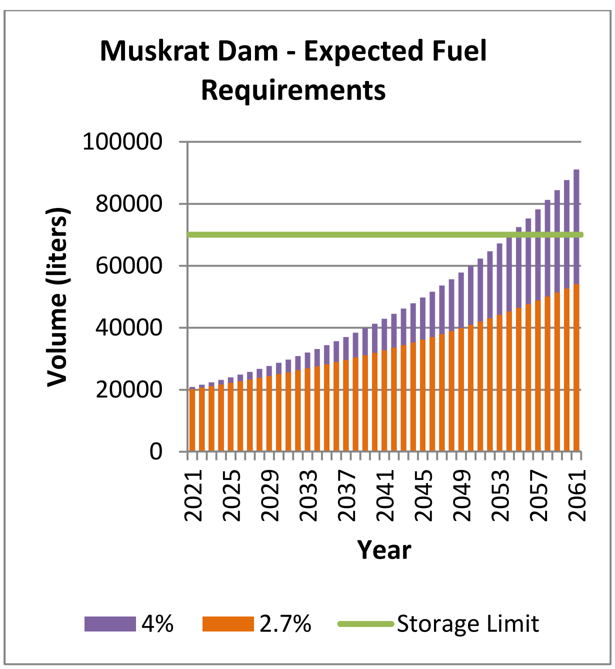


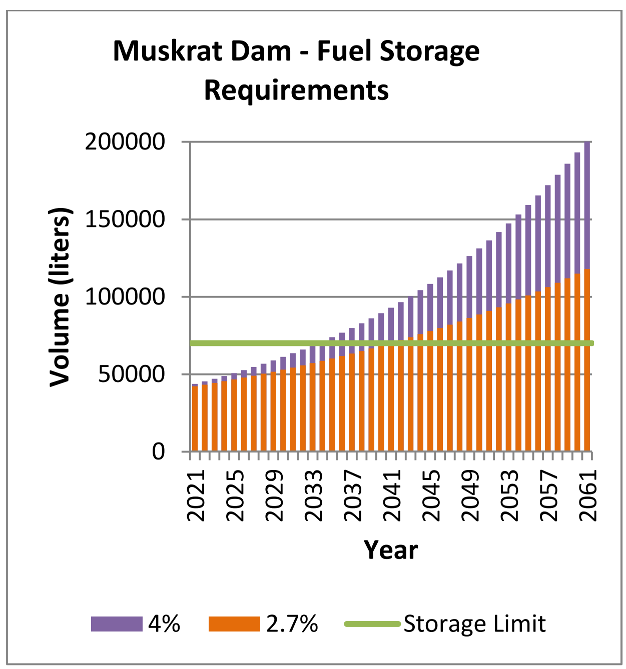


Muskrat Dam DGS Summary

Proposed Configuration	
Genset Rating (kW)	1400
Number of 80,000L fuel tanks	1
Transformer Rating (kVA)	3000
2030 Peak Demand (kW)	1180
2030 Fuel requirement without major outage (L)	29000
2030 Fuel requirement with major outage (L)	61000
Year additional generation required for full community backup	2035
Year additional fuel storage required with major outage	2034
Year additional transformation capacity required	2054

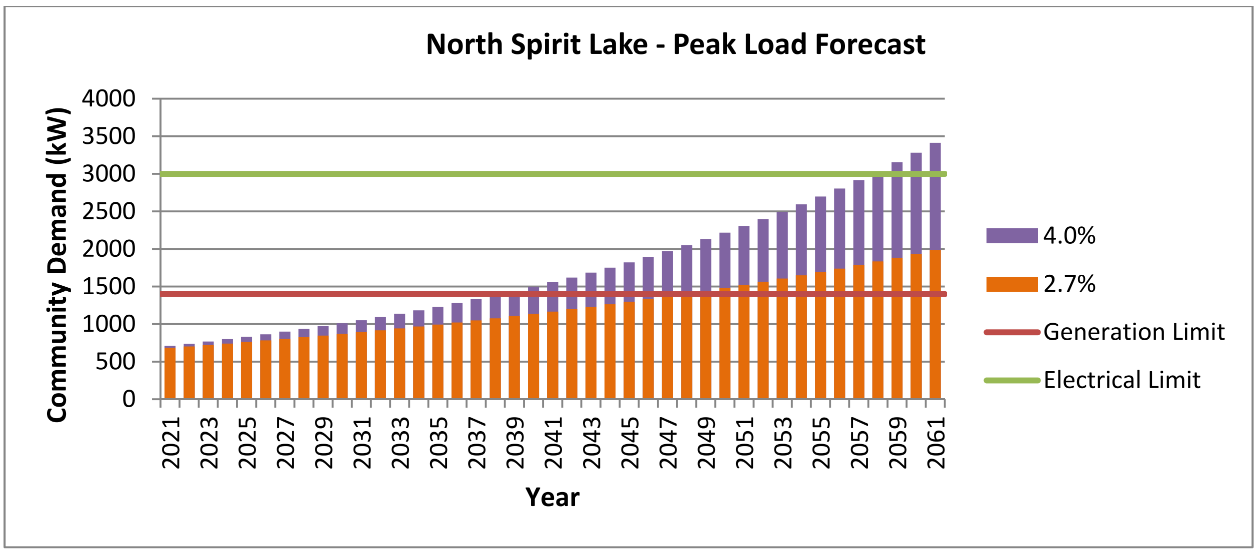


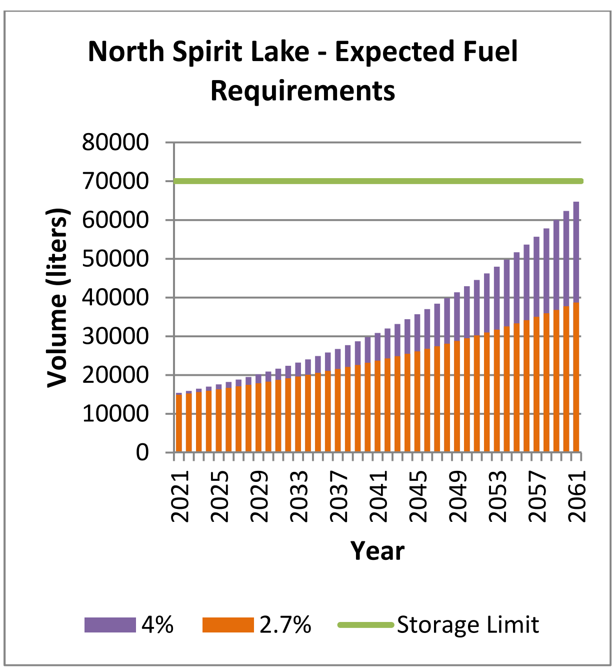


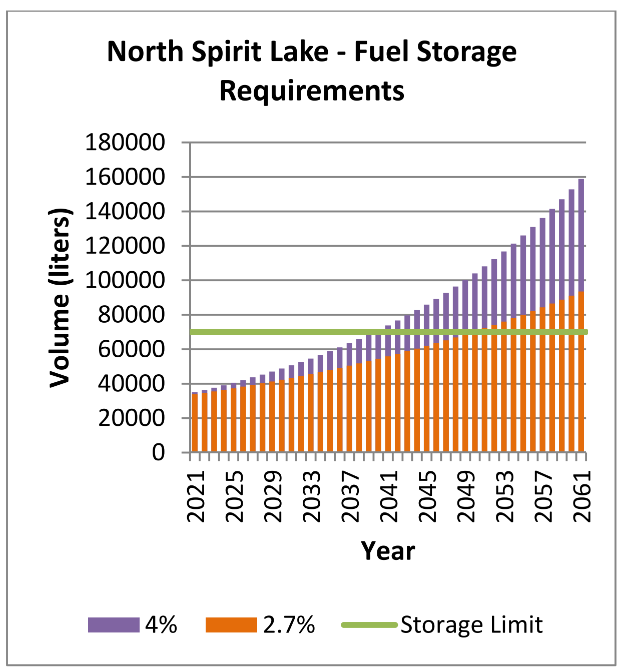


North Spirit Lake DGS Summary

Proposed Configuration	
Genset Rating (kW)	1400
Number of 80,000L fuel tanks	1
Transformer Rating (kVA)	3000
2030 Peak Demand (kW)	1012
2030 Fuel requirement without major outage (L)	21000
2030 Fuel requirement with major outage (L)	49000
Year additional generation required for full community backup	2039
Year additional fuel storage required with major outage	2040
Year additional transformation capacity required	2058

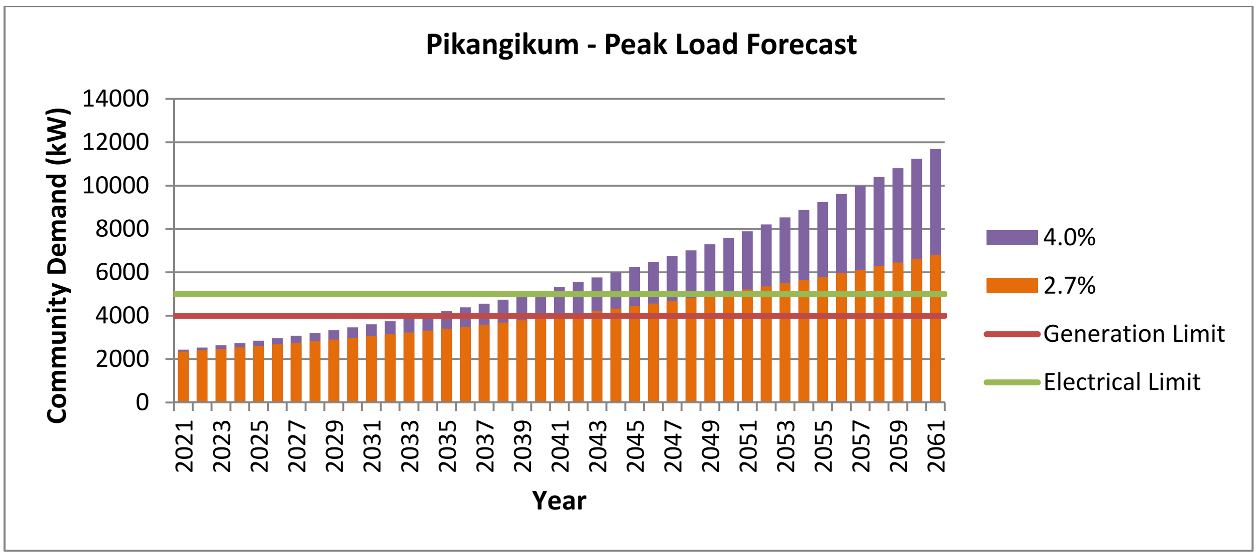


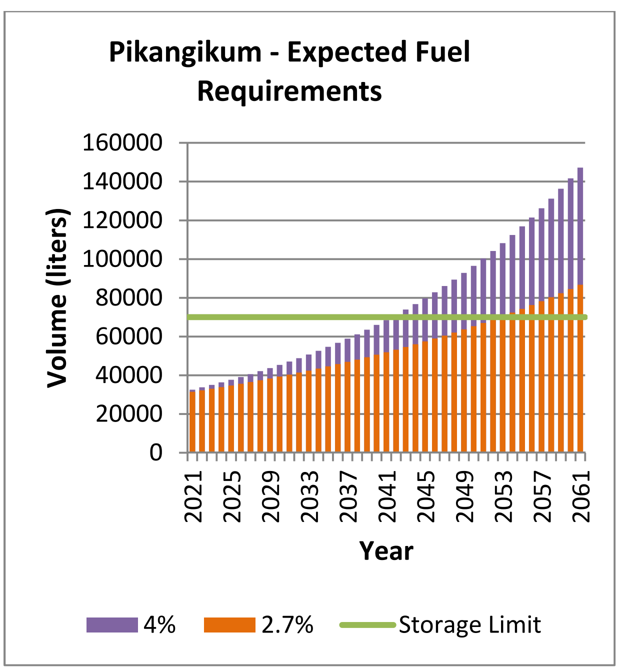


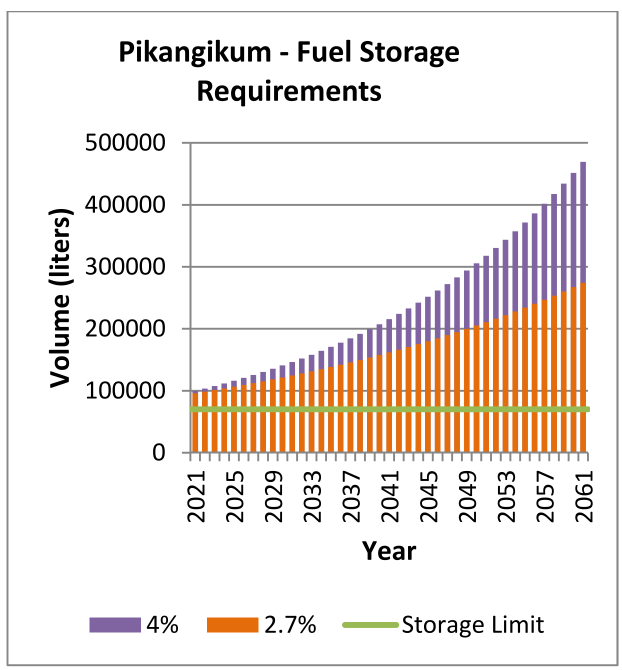


Pikangikum DGS Summary

Proposed Configuration	
Genset Rating (kW)	4000
Number of 80,000L fuel tanks	1
Transformer Rating (kVA)	5000
2030 Peak Demand (kW)	3465
2030 Fuel requirement without major outage (L)	45000
2030 Fuel requirement with major outage (L)	141000
Year additional generation required for full community backup	2034
Year additional fuel storage required with major outage	N/A
Year additional transformation capacity required	2040

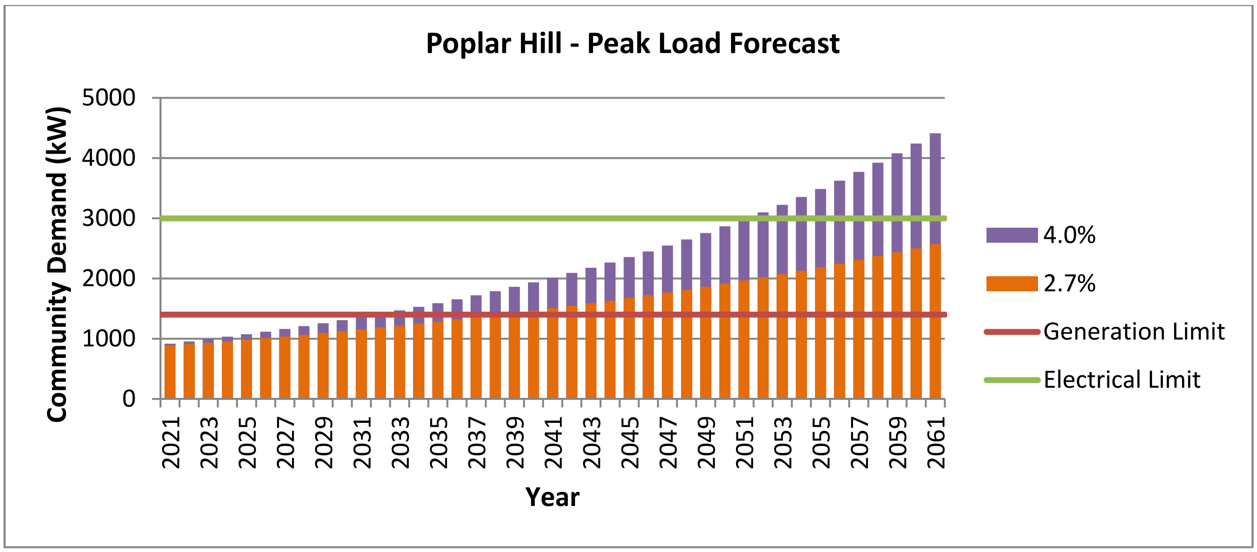


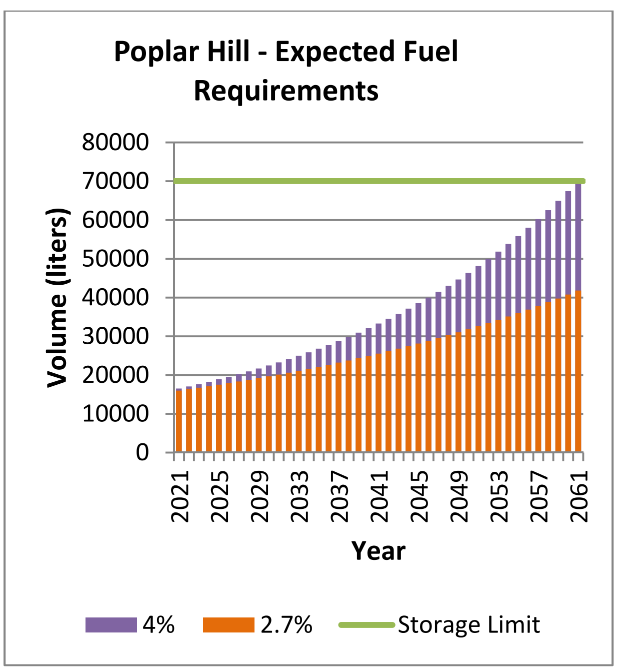


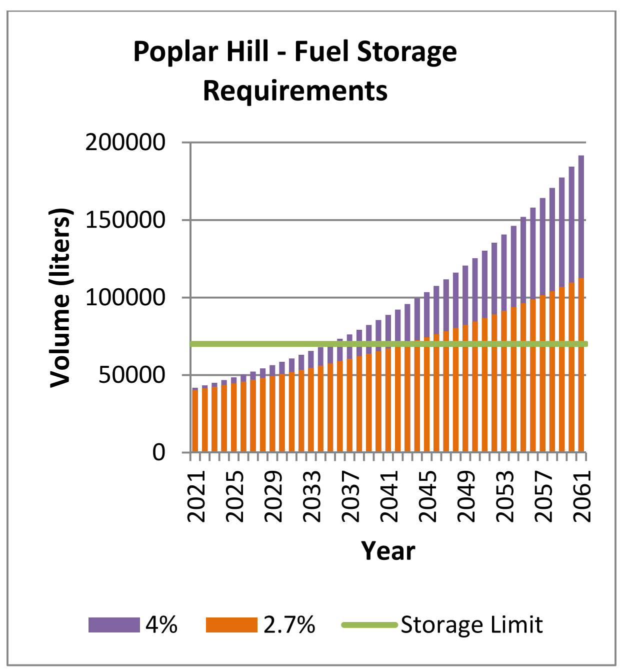


Poplar Hill DGS Summary

Proposed Configuration	
Genset Rating (kW)	1400
Number of 80,000L fuel tanks	1
Transformer Rating (kVA)	3000
2030 Peak Demand (kW)	1308
2030 Fuel requirement without major outage (L)	23000
2030 Fuel requirement with major outage (L)	59000
Year additional generation required for full community backup	2032
Year additional fuel storage required with major outage	2035
Year additional transformation capacity required	2052

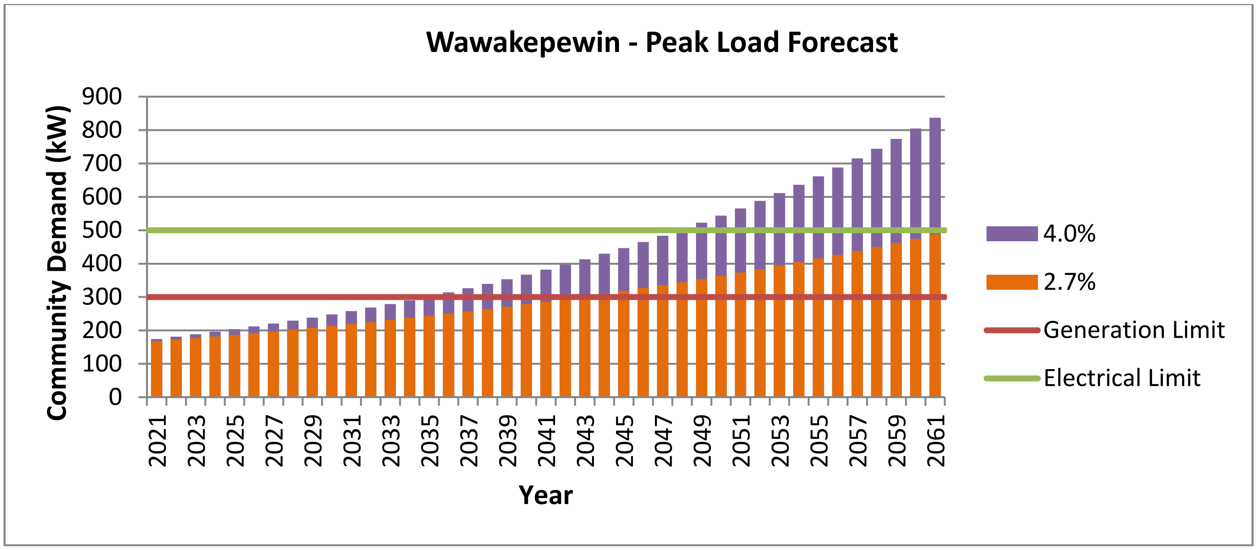


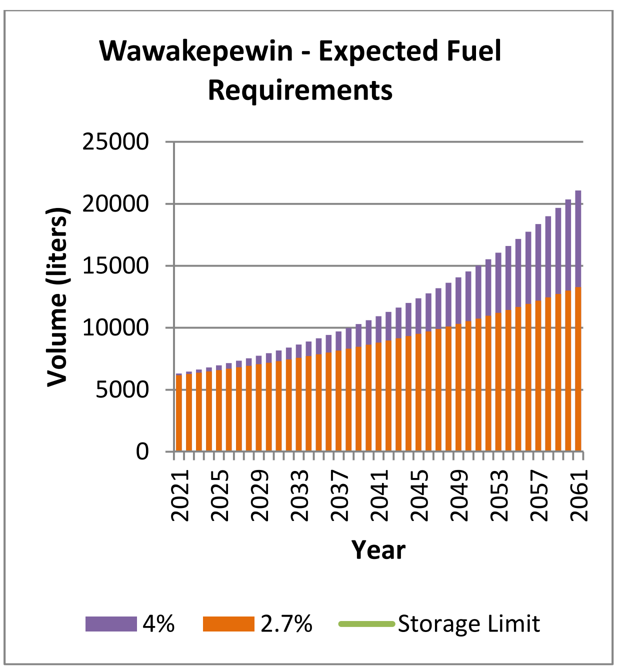


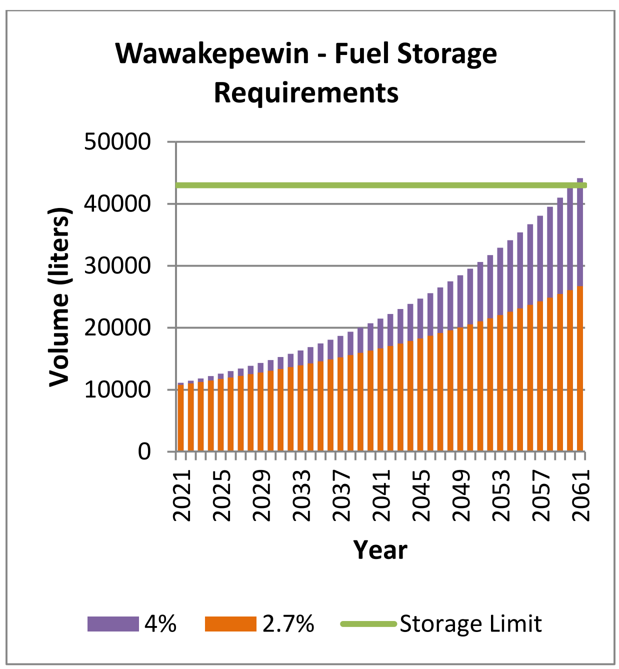


Wawakepewin DGS Summary

Proposed Configuration	
Genset Rating (kW)	300
Number of 50,000L fuel tanks	1
Transformer Rating (kVA)	500
2030 Peak Demand (kW)	248
2030 Fuel requirement without major outage (L)	8000
2030 Fuel requirement with major outage (L)	15000
Year additional generation required for full community backup	2035
Year additional fuel storage required with major outage	2061
Year additional transformation capacity required	2048

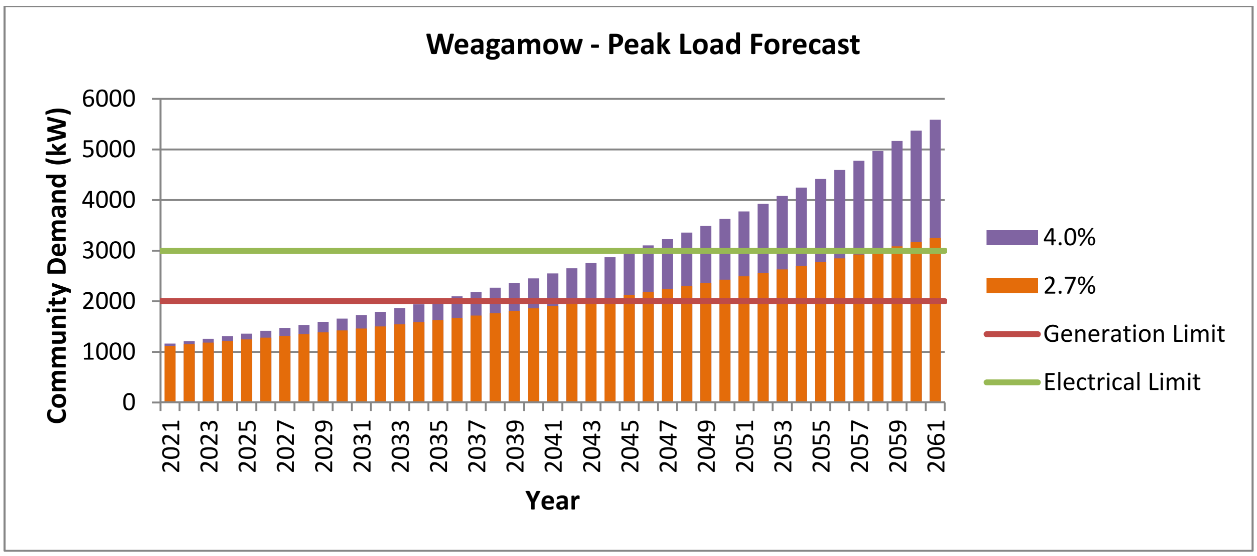


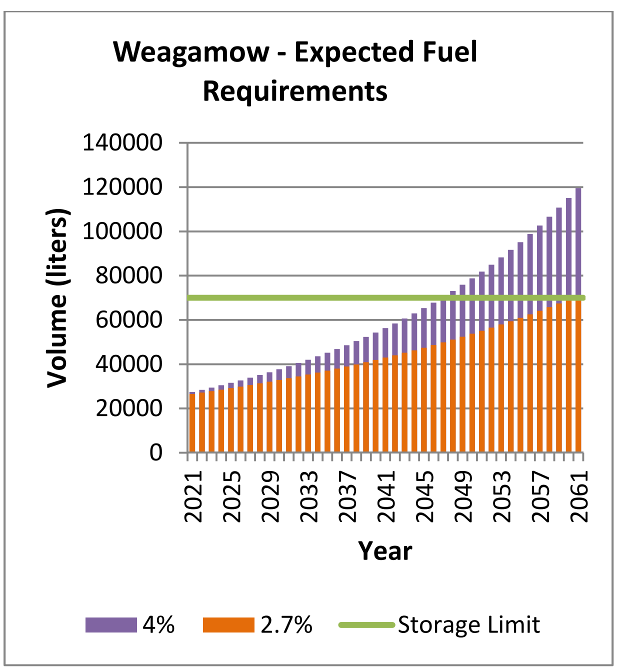


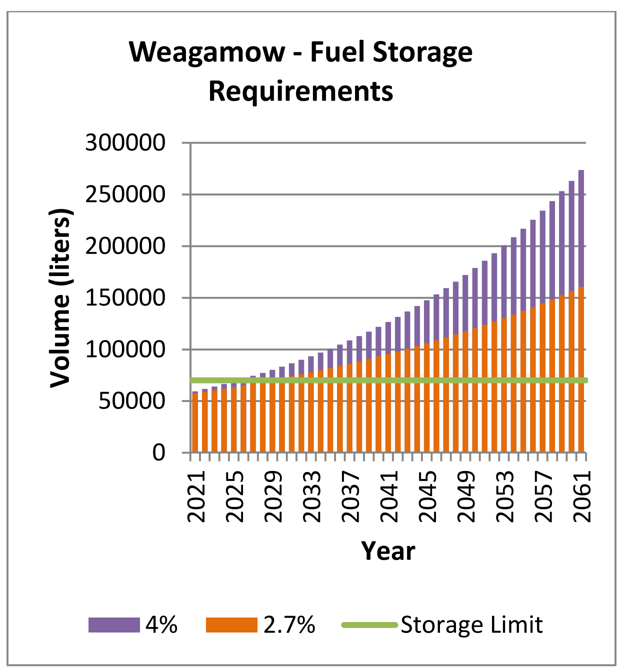


Weagamow DGS Summary

Proposed Configuration	
Genset Rating (kW)	2000
Number of 80,000L fuel tanks	1
Transformer Rating (kVA)	3000
2030 Peak Demand (kW)	1657
2030 Fuel requirement without major outage (L)	38000
2030 Fuel requirement with major outage (L)	83000
Year additional generation required for full community backup	2035
Year additional fuel storage required with major outage	N/A
Year additional transformation capacity required	2046

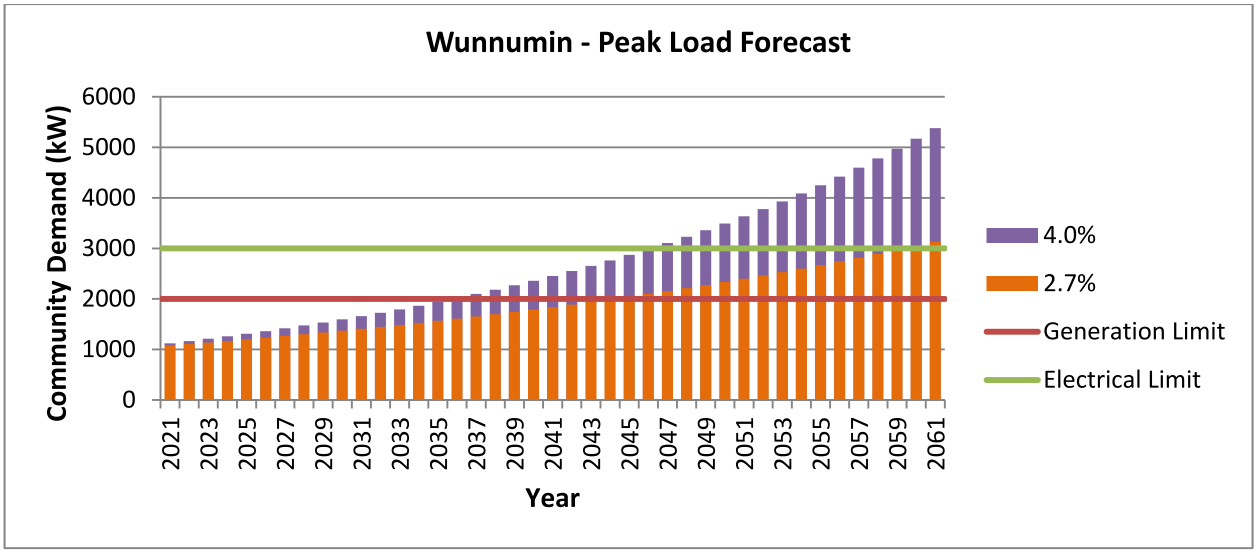


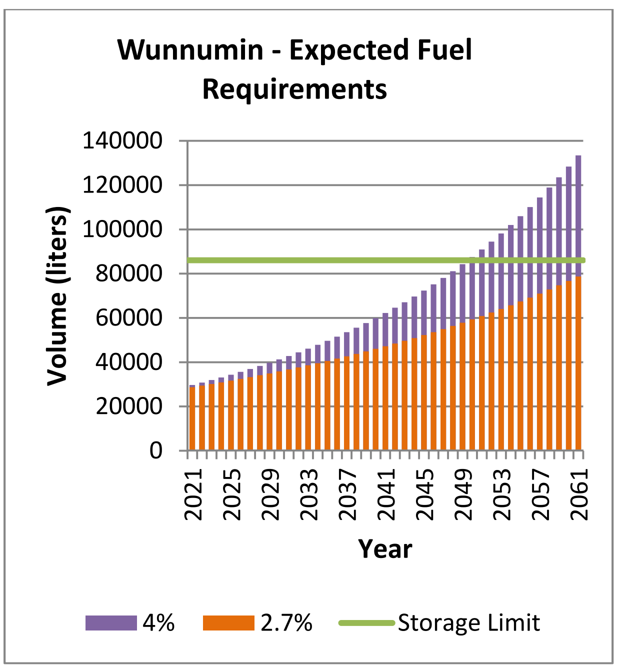


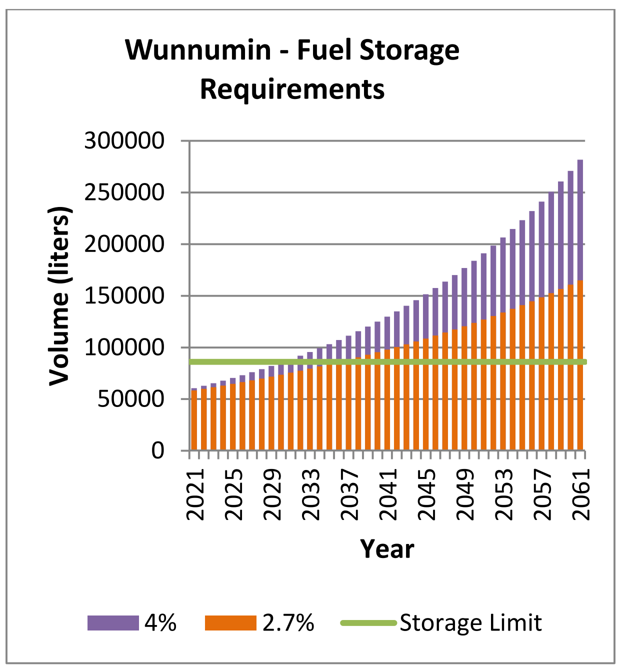


Wunnumin Lake DGS Summary

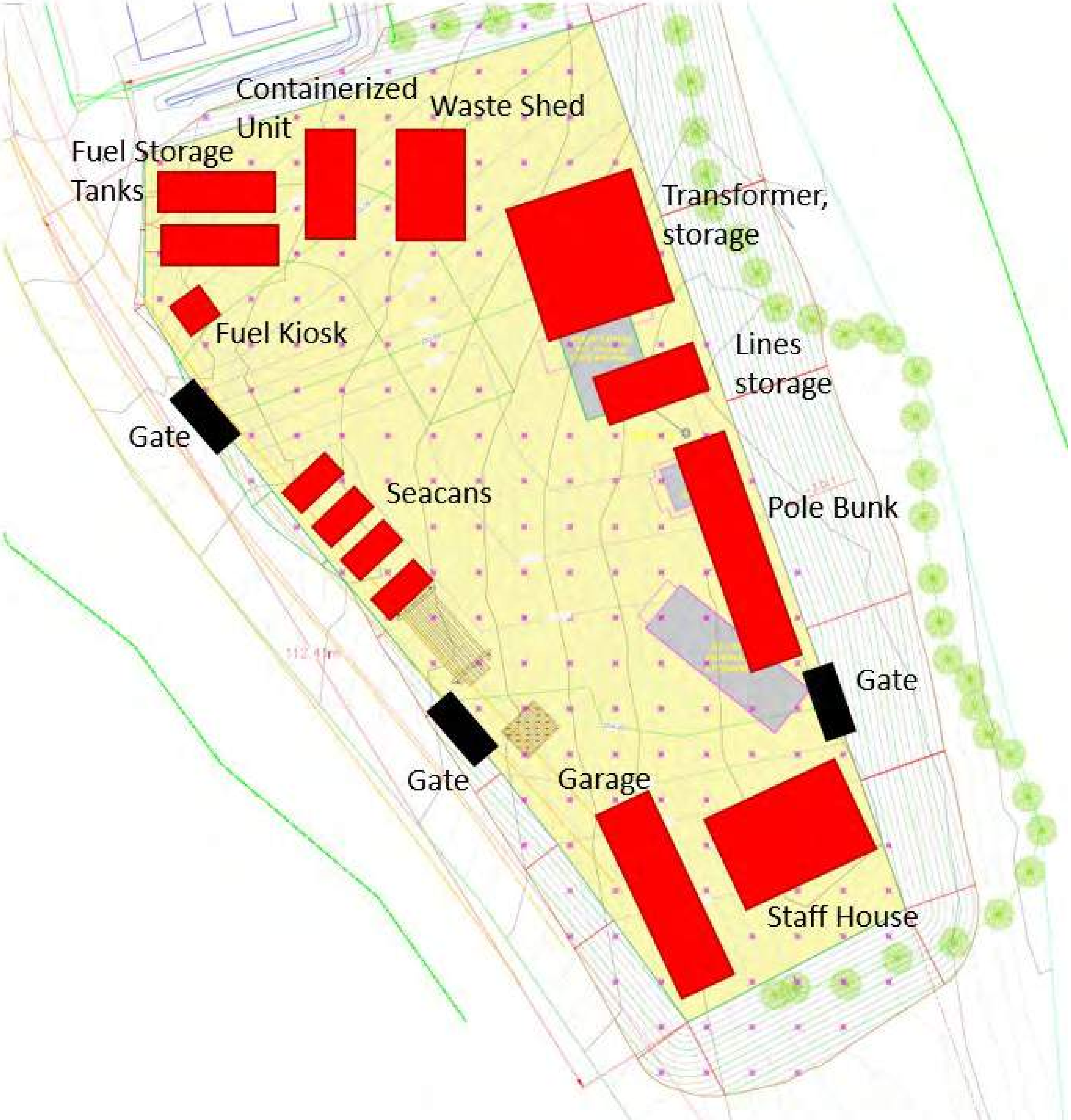
Proposed Configuration	
Genset Rating (kW)	2000
Number of 50,000L fuel tanks	2
Transformer Rating (kVA)	3000
2030 Peak Demand (kW)	1595
2030 Fuel requirement without major outage (L)	41000
2030 Fuel requirement with major outage (L)	85000
Year additional generation required for full community backup	2036
Year additional fuel storage required with major outage	2030
Year additional transformation capacity required	2047







APPENDIX 3 – REFERENCE SITE LAYOUT - WUNNUMIN


Containerized
Unit
Waste Shed
Fuel Storage
Tanks
Transformer,
storage
Fuel Kiosk
Lines
storage
Gate
Seacans
Pole Bunk
Gate
Gate
Garage
Staff House

APPENDIX 4 – NEW IPA STATIONS COST SUMMARY

Cost Summary

	Keewaywin	Muskrat Dam	North Spirit Lake	Pikangikum	Poplar Hill	Wawakapewin	Weagamow	Wunnumin Lake	
Site Preparation	$366,000	$366,000	$366,000	$393,000	$366,000	$272,000	$366,000	$366,000	
Design	$293,000	$293,000	$293,000	$333,000	$293,000	$289,000	$293,000	$306,000	
Remotes Site Work	$119,000	$119,000	$119,000	$135,000	$119,000	$139,000	$119,000	$135,000	
Material	$1,552,000	$1,552,000	$1,552,000	$3,408,000	$1,552,000	$1,003,000	$1,952,000	$2,062,000	
Contractor Installation	$914,000	$914,000	$914,000	$1,048,000	$914,000	$935,000	$819,000	$1,040,000	
Total	**$3,244,000**	**$3,244,000**	**$3,244,000**	**$5,317,000**	**$3,244,000**	**$2,638,000**	**$3,549,000**	**$3,909,000**	**$28,389,000**
10% Contingency	$324,400	$324,400	$324,400	$531,700	$324,400	$263,800	$354,900	$390,900	**$2,838,900**
Total with contingency	**$3,568,400**	**$3,568,400**	**$3,568,400**	**$5,848,700**	**$3,568,400**	**$2,901,800**	**$3,903,900**	**$4,299,900**	**$31,227,900**

Highlighted stations are identical other than differences in site layout

APPENDIX 5 – ASSUMPTIONS

- Travel to Wawakapewin has been estimated on the assumption that there will not be an all season road in place during construction. Flight costs were estimated to Kasabonika with additional costs for a helicopter or float plane based in Kasabonika being used for travel to Wawakapewin. If transportation between Kasabonika and Wawakapewin is not available locally, travel costs will be higher.

Site preparation

- Work sub-contracted by contractor to First Nation using local employees and First Nation equipment
- Contractor supplied site monitor on site for duration
- 6 weeks of work:
    - 2 weeks to clear trees & stumps, and level site
    - 4 weeks to place aggregate to final grade (based on aggregate requirements and two trucks delivering 10 loads/day each)
- First Nation rates as follows (based on recent rates from two communities):
    - Labourers @ $25/hr
    - Equipment operators @ $30/hr
    - Heavy equipment @ $250/hr including fuel
    - Gravel truck @ $200/hr including fuel and machine to load at pit
- Granular requirements:
    - 60m x 60m site at 1m thick requires 3600m^3
    - $100/m^3 delivered to site
- Additional material required to bring site to proper grade prior to aggregate installation would be an extra cost
- All site preparation costs are prorated (58% backup project/42% distribution yard project) based on size of distribution yard (30m x 50m)
- Includes 10% project management/administration overhead for contractor

Design

- Backup station design completed by Remotes with the assistance of Remotes' engineering consultant. Remotes' consultant will create tender package including spec and provide project management services during construction

- A significant portion of the design applies to all 7 IPA sites so its cost is split among those sites
- Each site requires some site specific design because of slight differences between sites (yard layout, size of genset, number of tanks, connection to distribution system, available communication, etc)
- Remotes' consultant will prepare and submit environmental approval (EASR) to Ontario Ministry of the Environment, Conservation and Parks
- Two persons to attend factory acceptance testing at genset supplier's test facility
- Priced at cost without markup

Remotes Site Work

- 3 site visits with four remotes personnel during the construction phase to inspect progress
- One week trip for an engineer and tech to install and program the SCADA and communication equipment
- One week trip for two engineers and two techs to completely commission the station alongside the contractor
- Priced at cost without markup

Material

- Geotech fabric for entire site (12-300'x15' rolls @ $500/roll)
- Fencing (800'@ $20/foot with three double wide vehicle gates)
- Genset (based on quotes for both Cummins and Caterpillar gensets installed in custom containers)
- Ehouse for SCADA and communication equipment
- Bulk Fuel Tank (Westeel quote is $80,000 for 80,000L tank but requires larger catwalks so $90,000 used)
- Fuel offload kiosk, piping, and associated equipment
- Waste storage shed for new and used oil
- Concrete (premixed in bags, 20yd^3 @ $600/yd^3)
- Styrofoam (40'x20'x8" under the tank and the genset (200 sheets each) @ $50/sheet)
- Transformer with vault
- Spare Transformer (one common spare rather than a spare at each site, 1/7 of cost applied to each backup station, to be stored in Thunder Bay)
- Viper switch required at connection to distribution system (assumed that three phase distribution lines of appropriate conductor size exist along road at new site)

- Power cables (assume 3/phase @ 100' each = 275m @ $100/m for 1000MCM Teck)
- 4 yard lights with poles
- Miscellaneous electrical components
- 4 storage seacans @ $5000 each with shelving ($2000 each)
- SCADA equipment
- Communication equipment (assumed that high speed internet connection is available along road at new site)
- Freight to staging area in Pickle Lake/Red Lake (12 loads @ $2500/load)
- Winter Road Freight (12 loads @ $7000/load) – used $4000/load for all season access into Weagamow
- All material marked up 10% by contractor

Contractor Installation

- 10 weeks on site (12 weeks for Pikangikum and Wunnumin because of extra genset and tank)
- 2 week trips, chartered flights in and out, 12 twelve-hour days per 2 week trip
- 2-day trip for two people to unload freight arriving by inter road, 4 days of crane rental with travel to site, crane rental rate of $195/hr
- 1 week of mobilization at contractor's workshop
- Trip #1 - Mobilization of tools and equipment at site, fence installation, viper switch installation, 2 First Nation labourers
- Trip #2 - Pour concrete pads for genset & tank, place concrete vault for transformer, dig trench for power cables between genset and transformer (direct buried), install and bury power cables close to each termination point, prepare for genset, tank, transformer placement, 3 First Nation labourers, one First Nation equipment rental for duration of trip, sand for backfill of trench
- Trip #3 - Place fuel tank and kiosk, install instruments, pump, electrical in kiosk, and pipe to genset, 3 First Nation labourers, one First Nation equipment rental for duration of trip
- Trip #4 - Place genset, place transformer, connect fuel pipe, contractor commissioning of fuel system, connect power cables at each end, 3 First Nation labourers, one First Nation equipment rental for half of trip
- Trip #5 - Yard lighting, site clean-up, work with Remotes for full backup commissioning, demobilization, 3 First Nation labourers, one First Nation equipment rental for half of trip
- Construction work marked up by 30% above Remotes' construction costs to account for contractor premium

APPENDIX 6 – UPDATED BACKUP GENERATION COST SUMMARY

Back Up Generation
Summary of Costs
4.0% Growth

OPERATION TO 2030

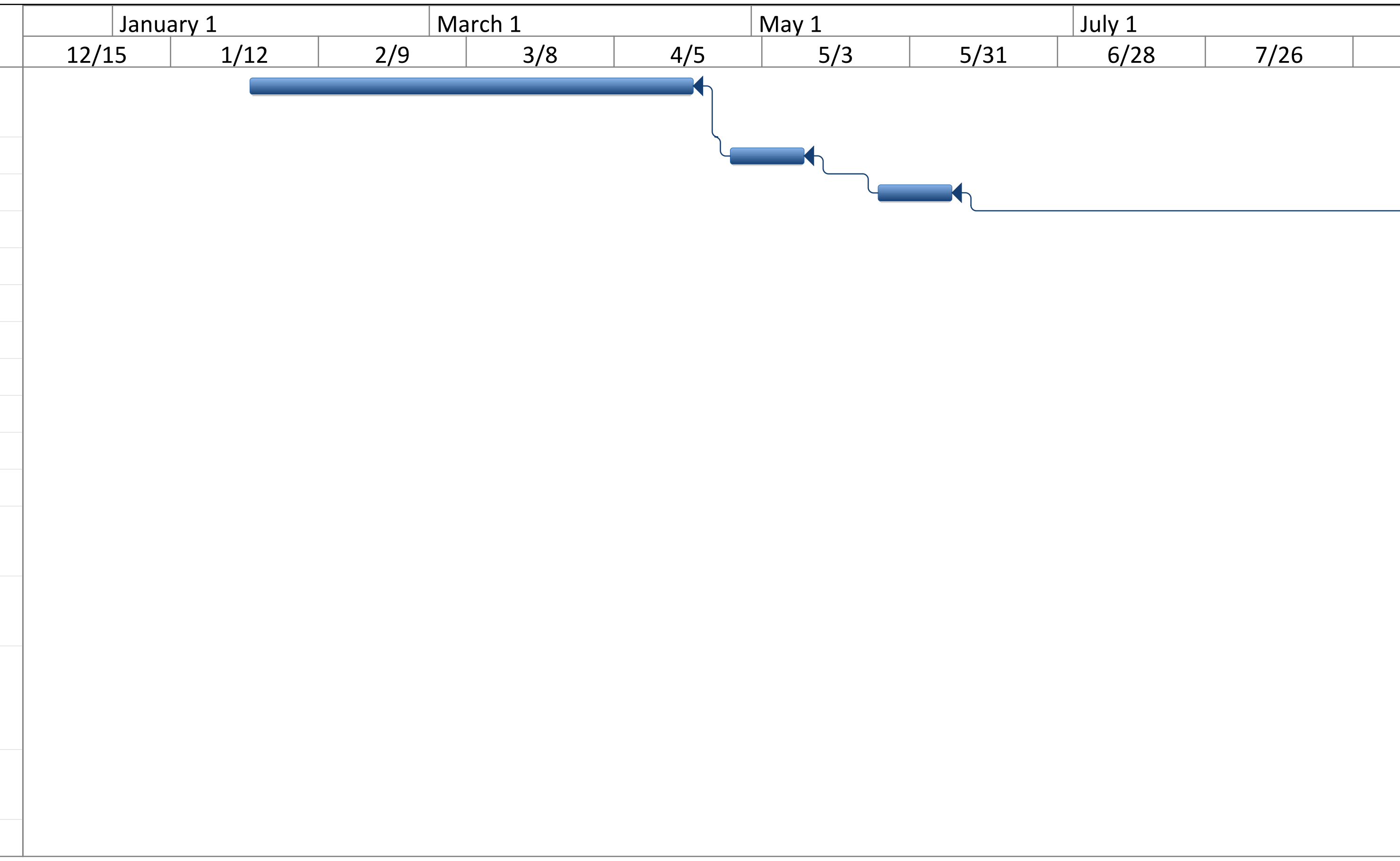
Year	Item	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
Site		1	2	3	4	5	6	7	8	9	10	11	
Bearskin Lake													
	Capital				$ 118,000								
	O&M					$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	
Deer Lake													
	Capital		$ 118,000										
	O&M			$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	
Kasabonika Lake													
	Capital				$ 118,000				$ 450,000				
	O&M					$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	
Keewaywin													
	Capital			$ 3,568,400	$ 44,000								
	O&M				$ 169,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	
Kingfisher													
	Capital		$ 118,000										
	O&M			$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)													
	Capital				$ 118,000								
	O&M					$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	
Muskrat Dam													
	Capital			$ 3,568,400	$ 44,000								
	O&M				$ 169,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	
North Spirit Lake													
	Capital			$ 3,568,400	$ 44,000								
	O&M				$ 169,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	
Pikangikum													
	Capital		$ 5,848,700	$ 43,000									
	O&M			$ 169,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	
Poplar Hill													
	Capital		$ 3,568,400	$ 43,000									
	O&M			$ 169,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	
Sachigo Lake													
	Capital				$ 118,000								
	O&M					$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	
Sandy Lake													
	Capital			$ 118,000									
	O&M				$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	
Wapekeka													
	Capital				$ 118,000								
	O&M					$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	
Wawakapewin													
	Capital			$ 2,901,800	$ 44,000								
	O&M				$ 169,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	
Weagamow (North Caribou Lake)													
	Capital		$ 3,903,900	$ 43,000									
	O&M			$ 169,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	
Wunnumin Lake													
	Capital		$ 4,299,900	$ 43,000									
	O&M			$ 169,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	$ 184,000	
													TOTALS to 2030
CURRENT YEAR (UNESCALATED)	**Fuel**		$ -	$ 251,000	$ 472,000	$ 742,000	$ 769,000	$ 797,000	$ 826,000	$ 856,000	$ 888,000	$ 921,000	**$ 6,522,000**
	O&M		$ -	$ 1,126,000	$ 2,087,000	$ 3,272,000	$ 3,272,000	$ 3,272,000	$ 3,272,000	$ 3,272,000	$ 3,272,000	$ 3,272,000	**$ 26,117,000**
	Capital - Transitional Costs		$ 236,000	$ 118,000	$ 590,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 944,000**
	Capital - Operator Training		$ -	$ 172,000	$ 176,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 348,000**
	Capital - New Stations		$ 17,620,900	$ 13,607,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 31,227,900**
	Capital - Upgrades		$ -	$ -	$ -	$ -	$ -	$ -	$ 450,000	$ -	$ -	$ -	**$ 450,000**
	Total O&M		$ -	$ 1,377,000	$ 2,559,000	$ 4,014,000	$ 4,041,000	$ 4,069,000	$ 4,098,000	$ 4,128,000	$ 4,160,000	$ 4,193,000	**$ 32,639,000**
	Total Capital		$ 17,856,900	$ 13,897,000	$ 766,000	$ -	$ -	$ -	$ 450,000	$ -	$ -	$ -	**$ 32,969,900**
	Total Backup Costs		$ 17,856,900	$ 15,274,000	$ 3,325,000	$ 4,014,000	$ 4,041,000	$ 4,069,000	$ 4,548,000	$ 4,128,000	$ 4,160,000	$ 4,193,000	**$ 65,608,900**
ESCALATED COSTS	**Fuel**		$ -	$ 262,000	$ 500,000	$ 797,000	$ 839,000	$ 884,000	$ 931,000	$ 980,000	$ 1,031,000	$ 1,086,000	**$ 7,310,000**
	O&M		$ -	$ 1,195,000	$ 2,259,000	$ 3,613,000	$ 3,685,000	$ 3,758,000	$ 3,834,000	$ 3,910,000	$ 3,989,000	$ 4,068,000	**$ 30,311,000**
	Capital - Transitional Costs		$ 246,000	$ 125,000	$ 639,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 1,010,000**
	Capital - Operator Training		$ -	$ 183,000	$ 191,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 374,000**
	Capital - New Stations		$ 18,333,000	$ 14,440,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 32,773,000**
	Capital - Upgrades		$ -	$ -	$ -	$ -	$ -	$ -	$ 527,000	$ -	$ -	$ -	**$ 527,000**
	Total O&M		$ -	$ 1,457,000	$ 2,759,000	$ 4,410,000	$ 4,524,000	$ 4,642,000	$ 4,765,000	$ 4,890,000	$ 5,020,000	$ 5,154,000	**$ 37,621,000**
	Total Capital		$ 18,579,000	$ 14,748,000	$ 830,000	$ -	$ -	$ -	$ 527,000	$ -	$ -	$ -	**$ 34,684,000**
	Total Backup Costs		$ 18,579,000	$ 16,205,000	$ 3,589,000	$ 4,410,000	$ 4,524,000	$ 4,642,000	$ 5,292,000	$ 4,890,000	$ 5,020,000	$ 5,154,000	**$ 72,305,000**

Index	**2.0%**
Cost of Capital	**0%**

Notes: Costs in table are in current year dollars. Totals at bottom are in Current and Future dollars using index at bottom of table
Capital for transitional costs are incurred one year before expected connection date
Yearly costs coincide with connection date year

APPENDIX 7 – TYPICAL PROJECT SCHEDULE

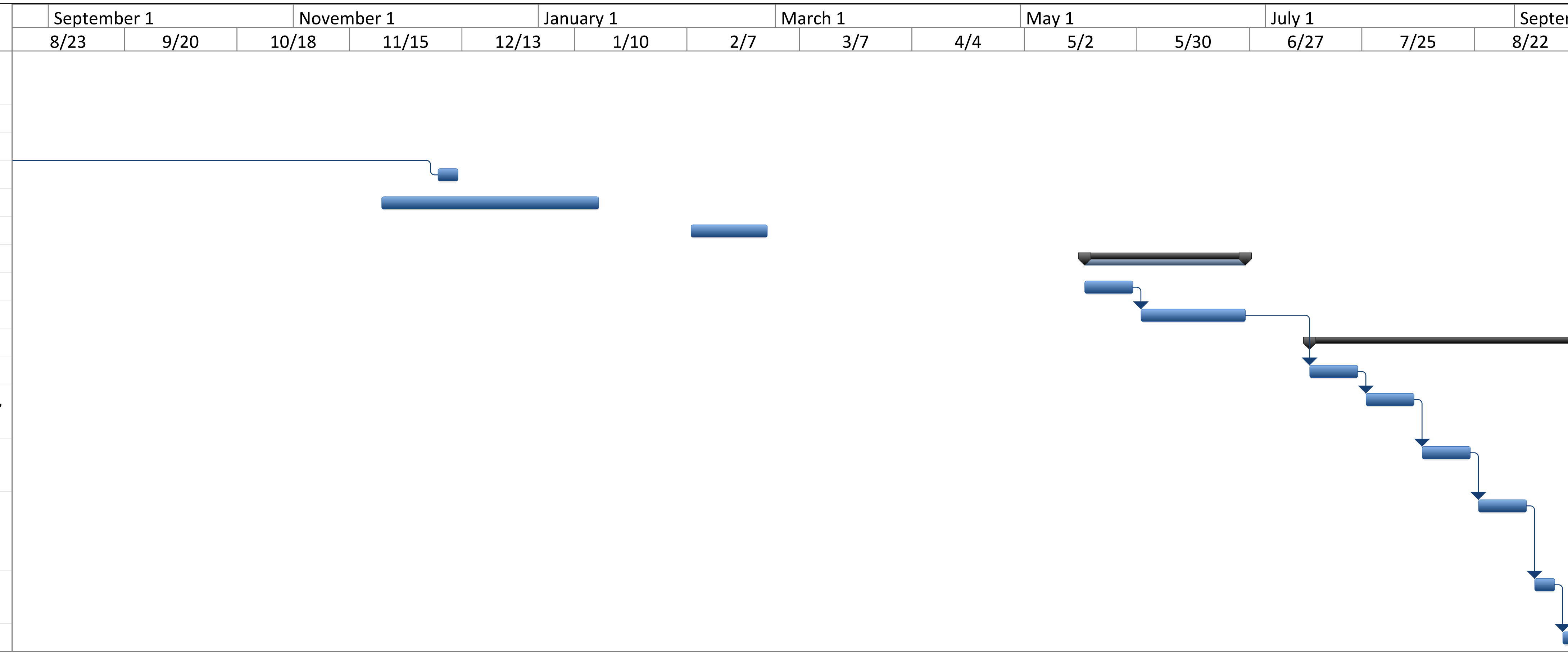
ID		Task Mode	Task Name	Duration	Start	Finish	Predecessors
1			**Design - Common (this is only required before the first site specific design)**	12 wks	Mon 1/27/20	Mon 4/20/20	2SF-1 wk
2			**Design - Site Specific**	2 wks	Mon 4/27/20	Mon 5/11/20	3SF-2 wks
3			**Long-lead Procurement**	2 wks	Mon 5/25/20	Mon 6/8/20	4SF-26 wks
4			**Genset Testing**	1 wk	Mon 12/7/20	Fri 12/11/20	
5			**Material Procurement**	2 mons	Mon 11/23/20	Fri 1/15/21	
6			**Winter Road Delivery**	3 wks	Mon 2/8/21	Fri 2/26/21	
7			**Site Preparation**	**30 days**	**Mon 5/17/21**	**Fri 6/25/21**	
8			Clear trees, remove stumps, level site	2 wks	Mon 5/17/21	Fri 5/28/21	
9			Aggregate and Grading	4 wks	Mon 5/31/21	Fri 6/25/21	8
10			**Contractor Installation**	**50 days**	**Mon 7/12/21**	**Fri 9/17/21**	
11			Mobilization, fence installation	2 wks	Mon 7/12/21	Fri 7/23/21	9FS+2 wks
12			Genset & tank foundations, transformer vault, power cables	2 wks	Mon 7/26/21	Fri 8/6/21	11
13			Kiosk, fuel tank, all fuel mechanical and electrical	2 wks	Mon 8/9/21	Fri 8/20/21	12
14			Genset, transformer, connect fuel and power cables, contractor commissioning of fuel system	2 wks	Mon 8/23/21	Fri 9/3/21	13
15			Full commissioning by contractor with Remotes present	1 wk	Mon 9/6/21	Fri 9/10/21	14
16			Yard lighting, site cleanup, demobilization	1 wk	Mon 9/13/21	Fri 9/17/21	15



Project: Backup Report - IPA Upda
Date: Mon 11/25/19

Task	Project Summary	Inactive Milestone	Manual Summary Rollup	Deadline
Split	External Tasks	Inactive Summary	Manual Summary	Progress
Milestone	External Milestone	Manual Task	Start-only	
Summary	Inactive Task	Duration-only	Finish-only	

ID		Task Mode	Task Name
1			**Design - Common (this is only required before the first site specific design)**
2			**Design - Site Specific**
3			**Long-lead Procurement**
4			**Genset Testing**
5			**Material Procurement**
6			**Winter Road Delivery**
7			**Site Preparation**
8			Clear trees, remove stumps, level site
9			Aggregate and Grading
10			**Contractor Installation**
11			Mobilization, fence installation
12			Genset & tank foundations, transformer vault, power cables
13			Kiosk, fuel tank, all fuel mechanical and electrical
14			Genset, transformer, connect fuel and power cables, contractor commissioning of fuel system
15			Full commissioning by contractor with Remotes present
16			Yard lighting, site cleanup, demobilization



Project: Backup Report - IPA Upda
Date: Mon 11/25/19

Task	Project Summary	Inactive Milestone	Manual Summary Rollup	Deadline
Split	External Tasks	Inactive Summary	Manual Summary	Progress
Milestone	External Milestone	Manual Task	Start-only	
Summary	Inactive Task	Duration-only	Finish-only	

Appendix F

Backup Power Plan for the Connecting Communities of the Wataynikaneyap Transmission Project

Backup Power Plan for the Connecting Communities of the Wataynikaneyap Transmission Project

Prepared by the:

Backup Power Working Group

April 30, 2020 GCDocs#48653196/Costing Table GCDocs#58987188

Page 592 of 798

Table of Contents

Page 593 of 798

Page 594 of 798

1. Executive Summary

This Backup Power Plan (the Plan) has been prepared to support the 16 First Nation communities ("Connecting Communities") being connected to the provincial transmission grid through the Wataynikaneyap Transmission Project. Previous studies have shown that without adequate backup power supply, the majority of the Connecting Communities would experience an increase in the frequency and duration of outages than they do currently. In addition, due to the remoteness and length of the transmission line, there is an increased risk of prolonged outages due to weather or forest fire. During engagement, the Connecting Communities have outlined the impacts of power outages, including: health & safety risks, food spoilage, damage to infrastructure, and overall community well-being.

This Plan is meant to act as a guiding document for identifying and implementing backup power in each Connecting Community prior to grid connection. This includes:

- The process and considerations for recommending a proposed option for each Connecting Community;
- The estimated costs and anticipated funding source(s);
- The expected implementation steps, timelines, and risks of the recommended option;
- The conditions for support from Indigenous Services Canada;
- The conditions for support from Hydro One Remote Communities Inc. ("Remotes") as the operator; and
- The supporting Band Council Resolutions from the Connecting Communities

Table 1 below outlines the recommended option for each community:

Table 1. Recommended Option for Each Community

First Nation	Current LDC	Recommended Option	Initial Capital Costs[2]	IPA Compliance/ Industry Standard[4]	Implementation Costs	ISC Health & Safety Critical Assets Backup Gaps	O&M and Fuel Costs to 2030	Total Costs
Bearskin Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$122,400	$1,767,108	**$2,027,508**
Deer Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$391,200	$2,321,055	**$2,850,255**
Kasabonika Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$150,400	$1,888,203	**$2,176,603**
Kingfisher Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$150,400	$2,202,541	**$2,490,941**
Kitchenuhmaykoosib Inninuwug	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$234,400	$2,375,161	**$2,747,561**
North Caribou Lake[3]	Remotes	Critical Asset Only	N/A	N/A	$100,000	$1,147,200	N/A	**$1,247,200**
Pikangikum[3]	Remotes	Critical Asset Only	N/A	N/A	$12,500	$122,400	N/A	**$134,900**
Sachigo Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$178,400	$1,781,469	**$2,097,869**
Sandy Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$150,400	$2,412,953	**$2,701,353**
Wapekeka	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$150,400	$1,741,026	**$2,029,426**
Keewaywin[5]	IPA	Re-purpose DGS	$684,000	$300,000	$680,000	$122,400	1,677,424	**$3,463,824**
Muskrat Dam[5]	IPA	Re-purpose DGS	$199,000	$300,000	$680,000	$178,400	1,704,496	**$3,061,896**
North Spirit Lake[5]	IPA	Re-purpose DGS	$209,000	$300,000	$680,000	$335,200	1,649,790	**$3,173,990**
Poplar Hill[5]	IPA	Re-purpose DGS	$199,000	$300,000	$680,000	$279,200	1,860,872	**$3,319,072**
Wawakapewin[3,5]	IPA	Critical Asset Only	N/A	N/A	$0	$0	N/A	**$0**
Wunnumin Lake[5]	IPA	Re-purpose DGS	$209,000	$300,000	$680,000	$150,400	2,006,226	**$3,345,626**
		Sub-totals	$2,444,000	$1,500,000	$3,672,500	$3,863,200	$25,388,324	$36,868,024

Notes:

1. Cost estimates are in 2019$.
2. Hydro One Remote Communities Inc. December 2018 report entitled "Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities" and and Hydro One Remote Communities Inc. November 2019 report entitled "Containerized DGS Option Annex".
3. Critical Assets Backup Gaps include all assets within ISC's LOSS; Implementation costs reflect CFMP policies.
4. IPA DGS must be in good operating condition and be in compliance with all applicable industry standards and legal regulations; estimated cost.
5. Operator Training for IPA Communities has been captured within O&M and Fuel Costs to 2030 costs.

Page 595 of 798

The recommended option for most Connecting Communities is to re-purpose the existing diesel generating station (DGS) until 2030, at a minimum. Repurposing an existing DGS is expected to require minimal capital investment and provide community-wide backup power.

However, as indicated in Table 1, backup power for ISC-funded critical assets is the recommended option for Pikangikum First Nation, as their DGS has reached its end-of-life and is being decommissioned, and for both Wawakapewin and North Caribou Lake First Nations as Remotes has indicated that each DGS cannot be re-purposed and operated by Remotes for community-wide backup. ISC is committed to ensuring there is backup power at ISC-funded critical assets.

ISC and Remotes have provided their conditions for re-purposing an existing DGS for community-wide backup power until 2030, at a minimum. Where the conditions are met, First Nations can apply to ISC for funding to support the transitional capital costs (includes Initial Capital Costs, IPA Compliance/Industry Standard Costs and Implementation costs) related to re-purposing a DGS and Remotes would be responsible for operations, maintenance, and any like for like replacement capital costs (O&M and Fuel costs to 2030). Even with community-wide backup, ISC is committed to ensure there is additional backup power for health and safety critical infrastructure (water and wastewater treatment facilities, lift stations, nursing station, and nurse residence), however, community-wide backup would replace the need for additional backup at a community gathering spot (e.g. schools) and fire hall.

This Plan provides a high-level overview of the requirements for each First Nation to implement their option prior to grid connection under ISC's Capital Facilities and Maintenance Program (CFMP). For IPA communities, there will be Operating Agreements with Remotes, which will also address responsibility for environmental contamination. For the Remotes-serviced communities, existing Electrification Agreements with Remotes will need to be amended or replaced. Once a community confirms their support for the recommended option, the implementation phase will begin and ISC officials will work with them to develop funding support applications.

Remotes has indicated that most DGS assets would be sufficient to provide backup power beyond 2030. Prior to 2030, ISC and Remotes have confirmed their willingness to work with the Connecting Communities to assess the need, costs, and benefit of ongoing backup power beyond 2030.

Please note, unfortunately, due to Covid-19 travel restrictions, only 4 of the 16 second round community engagement sessions could be completed. In order to advance backup power solutions in time with the grid connection schedule, the BPWG suggests shifting from planning to implementation of the recommended backup power solutions. Should there be any changes to the proposed Plan, those will be reflected through the implementation phase documents (e.g. funding support application, legal agreements).

Page 596 of 798

2. Background

Wataynikaneyap Transmission Project & Initial Assessment of Need for Backup Power:

Sixteen First Nation communities ("Connecting Communities") located in remote, northwestern Ontario will be connected to the Ontario transmission grid by the end of 2023 through the Wataynikaneyap Transmission Project. In 2014, Ontario's Independent Electricity System Operator ("IESO") completed a feasibility assessment for connecting these communities to the transmission grid. Due to the radial nature and remoteness of the lines, IESO estimated that communities would experience planned (for maintenance) and unplanned (e.g. due to weather) outages ranging from 0.81% to 2.09% per year (which equates to 70 to 183 hours per year). The expected duration of outages was not explored, but IESO did note that backup power should be required 5% of the time. IESO suggested that a combination of transmission and a backup power supply may result in similar or better reliability for Connecting Communities than the continued use of diesel generation only. As a result, IESO's 2016 Recommended Scope for the Wataynikaneyap Transmission Project called on Wataynikaneyap to facilitate the arrangement of backup power in the Connecting Communities as part of project planning, noting that it should – at a minimum – maintain power to critical buildings in the communities.

IESO's 2014 Remote Community Connection Plan can be accessed by visiting:
http://www.ieso.ca/en/Get-Involved/Regional-Planning/Northwest-Ontario/Remote-Community-Connection-Plan

IESO's 2016 Recommended Scope for the Wataynikaneyap Transmission Project Report is available at:
https://www.oeb.ca/oeb/_Documents/Documents/IESO_Report_Pickle_Lake_and_Remotes_Scope_20161013.pdf

BBA Backup Power Report (May 2018):

In response to IESO's findings and recommended scope, in 2016, Wataynikaneyap launched a process to facilitate backup power planning by identifying and communicating options and requirements for backup power to the Connecting Communities.

This included retaining the engineering firm BBA to assess backup power requirements, options and costs for the Connecting Communities ("BBA Report"). Similar to findings of IESO, BBA estimated that some communities would see a decrease in outages (within the Independent Power Authority ("IPA") serviced communities); however, the majority of communities would see an increase in outages (within the Remotes-serviced communities). BBA evaluated the common causes of interruptions and based on Wataynikaneyap's proposed design for the transmission line and the experiences in other jurisdictions, provided a refined transmission outage estimate of between 0.75% and 1.65% per year per community (which equates to 65 to 144 hours per year). The BBA Report also stated that the probability of outages will vary over time, with more outages occurring initially as design/construction issues are identified and addressed, which would be followed by a period of relative stability.

BBA analyzed various technological options for backup power (e.g. renewable energy, diesel generators), ultimately recommending that the existing diesel generation systems ("DGS") in the Connecting Communities be re-purposed to provide backup power for the near to medium term. The BBA Report also included recommendations for the design, construction and operations & maintenance of the transmission line to improve reliability. The BBA Report stated that, “outages requiring the backup power system can be reduced by 50% by implementing the good practices.” During Wataynikaneyap’s Leave to Construct process (more information below), Wataynikaneyap summarized how various controls recommended in the BBA Report have been incorporated into the Project’s design, including:

- A robust design (e.g. cross-arms and braces that are galvanized structural steel);
- The adjustment of routing to avoid permafrost and wetlands areas to the extent possible; and
- The implementation of redundant configuration in substation design by ensuring each substation supplying a Connecting Community contains two transformers, either of which is capable of supplying the entire load of the community.[1]

As a result of these design changes incorporated by Wataynikaneyap, it is possible that the Connecting Communities may in fact experience fewer outages than originally estimated by BBA.

The BBA Report contained information gaps including costs and operating requirements to convert and use the existing generators for backup power. In addition, community engagements and site visits were not undertaken as part of the development of the report. The BBA Report is provided in Appendix B. Due to these information gaps; further study was recommended by the First Nations.

<u>Hydro One Remote Communities Inc. Backup Power Report (December 2018 / November 2019) and Correspondence:</u>

Hydro One Remote Communities Inc. (“Remotes”) currently owns/operates diesel generating stations and local distribution systems in 10 of the 16 Connecting Communities and will become the owner/operator of local distribution systems for the remaining six communities in a grid-connected environment. As such, Remotes was identified as a potential operator of backup power in the Connecting Communities. In 2018, Opiikapawiin Services LP (“Opiikapawiin”) retained Remotes to determine the suitability of the existing DGS assets for backup power and costs associated with conversion from prime power to backup power. The “Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities” report (“Remotes Report-2018”), dated December 2018, determined that, in most cases, the existing DGS assets can be easily re-purposed to provide communal backup power with minimal initial capital investment.

The Remotes Report-2018 contained information gaps, including requirements for Remotes to own or operate DGS assets in the six IPA communities (e.g. related to environmental considerations) and steps to implement recommended backup power solutions. In November 2019, Remotes prepared a Containerized DGS Option Annex (“Remotes Report-Annex”), which provided costing related to Remotes owning and operating backup generating facilities in some communities by constructing new assets on greenfield sites. The Remotes Report-2018 is provided in Appendix C and the Remotes Report-Annex is provided in Appendix D.

---

[1] Wataynikaneyap Power LP. “Responses to Supplemental Interrogatories of Board Staff.” OEB Case Number: EB-2018-0190. 21-Jan-2019.

First Nations LP Shareholders Resolution (December 2018):

In December 2018, the 22 Shareholders (Chiefs), now 24, of First Nation LP ("FNLP") passed a resolution that Opiikapawiin represent the Connecting Communities in backup power planning discussions. All of the Connecting Communities invariably took the same position and passed a resolution in support of full communal backup power. The planning window for which backup power would be supported was set to 2030. During this time, the need, effectiveness, and costs associated with backup power could be better understood and justified. The need and costs for implementation of backup power beyond 2030 will be further studied during this planning window with the goal of a seamless continuation of backup power service. The Plan and commitments will need to address environmental responsibility and concerns, on a community-by-community basis, including all past and present grievances relating to historical environmental contaminations at the DGS sites. The Connecting Communities are shareholders of FNLP. The FNLP Shareholders Resolution related to backup power is provided in Appendix E.

Wataynikaneyap Leave to Construct Application & Approval (April 2019):

In order to build the Wataynikaneyap Transmission Project, Wataynikaneyap required approval from the Ontario Energy Board ("OEB"). During the Leave to Construct proceeding (EB-2018-0190), OEB staff, Wataynikaneyap, and Remotes discussed system reliability and backup power.

Both Remotes and OEB staff commented in their submissions that, without adequate backup power supply, the majority of the Connecting Communities would experience an increase in the frequency and duration of outages than they do currently.

Wataynikaneyap noted that outage frequency and duration are not the only ways to measure transmission system reliability. For example, the Transmission System Code (TSC) defines "reliability" in relation to electricity service as meaning, "the ability to deliver electricity in accordance with all applicable reliability standards and in the amount desired." IESO's Market Rules build on the TSC's definition, stating that "reliability" is "the ability to deliver electricity within reliability standards and in the amount desired and means, in respect of ... a transmission system, the ability of ... that transmission system to operate within reliability standards in an adequate and secure manner". Wataynikaneyap stated that the Remote Connection Line components of the project are designed to contribute most significantly to those aspects of reliability that relate to the ability to operate in an "adequate and secure manner" and to deliver electricity "in the amount desired." Wataynikaneyap also noted on several occasions that, while they can play a supporting role, securing supply of backup power is out of their control as the transmitter.

In its Decision and Order, the OEB stated that all parties agreed during the proceeding that backup power is an essential component for the Project's success, that there are multiple actors and diffuse responsibilities and authorities involved in the provision of backup power supply, and that IESO's 2016 Scope Document calls for Wataynikaneyap to facilitate the arrangement of the backup solutions. The OEB also noted that both Remotes and OEB staff expressed concerns about the risk that backup supply might not be secured: (a) on time (by the time communities are being grid connected); (b) in sufficient and appropriate quantities; and (c) for all Connected Communities, including current IPAs.

In the end, the OEB's approval of Wataynikaneyap's Leave to Construct application included a condition that Wataynikaneyap provide semi-annual reporting to the OEB on the progress of backup power supply arrangements for the Connecting Communities. These reports are submitted every April and October.

Page 599 of 798

Commitments for Backup Power Under the Wataynikaneyap Power Project Funding Framework (July 2019):

In the Parallel Process Agreement, executed by Canada, Ontario, Wataynikaneyap and FNLP in July 2019, the parties acknowledged that the following two reports were prepared in relation to backup power and the Connecting Communities: BBA Report (May 2018) and Remotes Report (December 2018).

Canada and FNLP agreed that they would continue to work together and with the Connecting Communities as well as involve other interested parties as appropriate (including Ontario, Wataynikaneyap, the IESO, and Remotes) to develop a backup power implementation plan and commitments for the Connecting Communities. This work would include consideration to appropriate reliability and service standards as well as to the utilization of existing DGS assets that are in a condition to be safely operated for such purposes in accordance with good utility practice.

Letters from Indigenous Services Canada to the Connecting Communities (December 2018 / November 2019):

In a letter to the Connecting Communities dated December 14, 2018, Indigenous Services Canada ("ISC") Ontario Regional Director General, Anne Scotton, stated that ISC is committed to provide backup power for the following ISC funded critical assets: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls. Backup power to these critical assets would meet ISC's Level of Service Standard (LOSS) for Electric Power Supply and Distribution Systems, as well as IESO's requirement for Wataynikaneyap to facilitate the arrangement of backup power resources that would be available, at a minimum, to maintain supply to essential loads within critical buildings.

The letter also stated that the existing diesel generating equipment may provide a useful source of backup power once communities are connected to the provincial transmission grid and that the Department would work with communities, Ontario's Ministry of Energy, Northern Development and Mines, and Remotes, to define the process to establish a backup power implementation plan and finalize an implementation plan in calendar year 2019.

In November 2019, ISC sent a subsequent letter to the Connecting Communities advising that due to the complexity of developing sustainable and reliable backup power options, a revised completion date of March 2020 had been identified by the Backup Power Working Group as achievable to finalize an implementation plan. These letters are included as Appendix F.

Formation of Backup Power Working Group (January 2019 to present):

In order to develop the implementation plan, ISC and Opiikapawiin (as mandated by FNLP) formed a Backup Power Working Group ("BPWG") with the objective of drafting a Backup Power Implementation Plan during the 2019 calendar year (subsequently updated to March 2020), for presentation to the Connecting Communities. The BPWG Terms of Reference is included as Appendix G.

While ISC's LOSS includes a guideline to provide backup power for ISC-funded critical assets when reliability concerns are demonstrated, ISC agreed to consider community-wide backup power for the Connecting Communities. Community-wide backup would respond to transmission system outages; Remotes has indicated that their local distribution service is on average 99.92% reliable, and that outages are typically short, and only affect a portion of the community. As such, community-wide backup power would replace the need for critical infrastructure backup at a community gathering spot (e.g. schools), as well as fire hall. Critical infrastructure

Page 600 of 798

backup power would still be required for critical assets which include: water & wastewater treatment facilities, lift stations, nursing stations, and nurse residence(s).

Expected Community Connection Dates:

Listed in Table 2 below are the expected grid connection dates for the Connecting Communities, according to the Wataynikaneyap Transmission Project energization schedule from October 2019:

Table 2 - Wataynikaneyap Transmission Project's Expected Date for Grid Connection

	First Nation	Remotes-Serviced or Independent Power Authority (IPA)	Expected Date for Energization
1	Pikangikum	Remotes-Serviced	Connected December 2018
2	Kingfisher Lake	Remotes-Serviced	September 2021
3	North Caribou Lake	Remotes-Serviced	January 2022
4	Poplar Hill	IPA	April 2022
5	Deer Lake	Remotes-Serviced	May 2022
6	Wunnumin Lake	IPA	July 2022
7	Sandy Lake	Remotes-Serviced	August 2022
8	Wawakapewin	IPA	September 2022
9	Bearskin Lake	Remotes-Serviced	September 2022
10	Muskrat Dam	IPA	September 2022
11	North Spirit Lake	IPA	October 2022
12	Kasabonika Lake	Remotes-Serviced	May 2023
13	Kitchenuhmaykoosib Inninuwug	Remotes-Serviced	May 2023
14	Sachigo Lake	Remotes-Serviced	May 2023
15	Wapekeka	Remotes-Serviced	May 2023
16	Keewaywin	IPA	May 2023

Source: Wataynikaneyap (February 10, 2020)

It will be important to align backup power activities and objectives with the expected connection dates, to the greatest extent possible.

1st Year Power Outage Statistics Following Pikangikum First Nation Grid Connection in December 2018:

Wataynikaneyap provided outage statistics from Pikangikum First Nation's first year of being connected to the provincial transmission grid. During 2019, Pikangikum First Nation experienced approximately 45 hours (cumulatively) of outages in the community. The total outage time for the first year of grid-connection is lower than the estimates from both the IESO and BBA. The majority of outages and outage hours were not directly attributed to Wataynikaneyap, but rather resulted from adjoining electrical transmission system infrastructure in Red Lake as well as faults on the local distribution system caused by small animals. The transmission outages related to local distribution faults may be due to interconnection issues and are expected to be reduced in subsequent years.

During the year, a large forest fire crossed Wataynikaneyap's transmission line and came in close proximity to the substation. The impact to Pikangikum's power supply was minimal; however, it could have been much worse.

Page 601 of 798

3. Purpose

The purpose of the Backup Power Plan ("the Plan") is to identify and evaluate backup power options, identify project partners, and describe the implementation steps to facilitate backup power in each Connecting Community prior to grid connection. The Plan outlines the:

- Process and outcome of selecting a proposed option for each Connecting Community;
- Estimated costs and funding source(s); and
- Expected implementation steps, timelines, and risks of the recommended option.

The Plan is meant to act as a guiding document for implementing unique backup power solutions in each Connecting Community.

4. Engagement Process

4.1. Engagement with Project Stakeholders

Table 3 – Summary of Project Stakeholders

	Name	**Role / Participation**
1.	***First Nation LP***	• The Connecting Communities are shareholders in First Nation LP • Committed to working with Canada to develop a backup power implementation plan • Mandated its affiliate Opiikapawiin to undertake backup power planning • Received updates at Board and Shareholder meetings
2.	***Opiikapawiin Services LP***	• Mandated by FNLP, including shareholders from the Connecting Communities, to facilitate backup power planning on behalf of FNLP • Member of the Backup Power Working Group • Co-author of the Plan
3.	***Tribal Councils***	• Provided updates on Opiikapawiin's bi-weekly planning calls • Provided a monthly update summary • Supports Opiikapawiin's community engagement • Review of draft Plan
4.	***Canada*** (Represented by ISC)	• Committed to work with FNLP (through Opiikapawiin) to develop a backup power implementation plan • Member of the Backup Power Working Group • Co-author of the Plan

Page 602 of 798

5.	***Wataynikaneyap Power***	• Proponent for the 1700km new transmission lines to the Connecting Communities • Required by OEB to provide semi-annual reporting on the progress of backup power • Provided information to the Connecting Communities on the expected reliability of the transmission line as well as high level options & requirements for backup power • Provided information on transmission system outages to date in Pikangikum
6.	***Hydro One Remote Communities Inc.***	• Currently owns/operates diesel generation stations and/or local distribution systems in 10 of the Connecting Communities • Engaged in the transfer process with the six IPA Connecting Communities to takeover local distribution service upon grid connection • Assessed the options and requirements for re-purposing existing DGS assets in the Connecting Communities from prime power to backup power • Assessed the costs to own and operate backup generating facilities by constructing assets on greenfield sites • Participates in some Backup Power Working Group meetings
7.	***Ontario Ministry of Energy, Northern Development, & Mines***	• Participates in Backup Power Working Group meetings • Develops energy policy in Ontario, including legislation governing the Ontario Energy Board (OEB) • Develops and administers (including through its agencies and the OEB) programs and services related to energy in Ontario, including the Rural or Remote Rate Protection (RRRP) subsidy program, which would contribute funding to operational costs of backup power

4.2. Engagement with the Connecting Communities

Prior to the formation of the BPWG, Wataynikaneyap engaged the Connecting Communities to provide information on expected outages and potential backup power options, including BBA's recommendation to utilize existing DGS assets for backup power. To ensure the Connecting Communities remained informed of the latest developments and provided with opportunities to share feedback, Opiikapawiin planned two rounds of engagement with each Connecting Community.

The objectives of the first round of engagement (2019) were to:

- Provide an update on planning activities
- Gather what each community's expectations are
- Confirm whether the First Nation supports utilizing existing DGS assets for backup power
- Discuss next steps

The objectives of the second round of engagement (2020) were to:

- Present the proposed option for backup power in each Connecting Community based on discussions with funding partners
- Present summary of the draft Plan for review and feedback
- Obtain support for the draft Plan in the form of an executed Band Council Resolution ("BCR")

Page 603 of 798

Summaries of both rounds of engagement with the Connecting Communities can be found in Appendix H. These summaries include dates of engagement, types of engagement, and outcomes from these engagements.

Note: Due to scheduling challenges and community closures related to COVID-19 precautions, not all community engagement sessions were held in each of the Connecting Communities.

Throughout Opiikapawiin's engagement, the Connecting Communities have highlighted many of the hardships as a result of power outages and reinforced the need for full community backup power supply. The list below provides a summary of these challenges, the majority of which can be avoided with full community-wide backup power:

Impact	Description
Health & Safety	• Extended outages during the winter increase the use of candles and lanterns for lighting which pose safety risks. There have been instances where houses have burnt down due to increased use of open flames during extended outages. • Elderly and people with disabilities are more at risk of facing health issues from inadequate heating during extended outages in the winter months (e.g. pneumonia). Relocating to centralized gathering spot is difficult and disruptive. • Extended outages pose significant health & safety risks to people reliant on medical equipment (e.g. home dialysis machines, sleep apnea machines, medical fluids that must be kept at constant temperature). • Lack of available home and street lighting raises the risk of slip & fall injuries, vehicular accidents, general disorientation, etc.
Food Spoilage	• Food spoilage during extended outages in summer months: – Wild animals and berries are a significant food source in the Connecting Communities; – Additional cost, time & effort required to replenish food inventory; – First Nations' beliefs place high importance on not wasting a harvested animal; and – Food costs are already extremely high.
Damage to Infrastructure	• Infrastructure (e.g. water supply in houses) is at risk of freezing during outages that occur in cold winter months. This is extremely disruptive to community members, and costs associated with repairing or replacing infrastructure (e.g. water pipes) are high.
Overall Community Well-Being	• Outages impact First Nations' ability to deliver programs, services, and projects, which leads to lost productivity and services for community members.
Reliability of Critical Asset Backup	• There are operations and maintenance challenges of a non-centralized backup plan that requires ongoing operation and maintenance of the individual backup systems. • Many individuals noted that critical asset backup often did not work.
Evacuations	• In the event of an extended outage, community members may need to be evacuated for health & safety reasons. • The monetary and economic costs of evacuations are high and extremely disruptive to communities, Tribal Councils, and supporting government departments. • Outages disrupt an individual's ability to spend time on the land to carry out traditional practices (hunting, gathering, spirituality), as they may be evacuated for health & safety reasons.

Page 604 of 798

5. Preliminary Options Analysis

In 2017, Wataynikaneyap retained the services of engineering firm BBA to assess backup power requirements for the Connecting Communities, options, advantages/disadvantages of each option, and a recommended option. The options assessed are summarized below:

Option	Comments from BBA Report
Solar	Solar energy is not always available. Could be combined with battery; however, batteries are costly, and may not perform as well in cold climates (although technologies are improving).
Wind	Wind energy not always available. Could be combined with battery; however, batteries are costly, and may not perform as well in cold climates (although technologies are improving).
Biomass	Slow response / start time, high upfront costs, high operations and maintenance costs.
Hydroelectric	Requires site with reservoir (storage). High initial cost with 5+ years to implement. Would need to be close to the transmission line or community.
Transmission Looping	Would require significant investment to build additional transmission line (e.g. connecting Keewaywin and Muskrat Dam). Due to the length of the line, the loop may not support all communities in the event of an outage.
Battery	Technology is considered immature and expensive, especially for remote areas. In addition, technology may not perform well in cold climates.
Diesel Generators	Lowest cost solution, best availability, can be implemented prior to grid connection. Primary drawback is environmental.

BBA concluded that re-purposing the existing diesel generators provides the best near- to medium-term solution based on cost, availability, implementation timeline, and operational requirements. Their study did indicate that the other options could be revisited in the medium- to long-term as technologies improve and costs decrease.

6. Backup Power Options Considered by the BPWG

Since the BBA report recommended utilizing the existing DGS assets in the Connecting Communities for backup power in the near- to medium-term, the BPWG focused on determining if the existing diesel generators could be re-purposed. In order to do so, the BPWG completed the following steps to assess the DGS backup power option for each community:

1) Determine if it is technically feasible to re-purpose the existing DGS assets in each Connecting Community for backup power, including any capital requirements for converting operation from prime to backup power;
2) Identify environmental or liability considerations that could prohibit utilizing the DGS assets for backup power;
3) Engage in discussions with Connecting Communities and funding partners; and
4) If the existing DGS assets cannot be re-purposed (based on 1 & 2 above), explore the following alternatives:
   a) Critical asset backup only;
   b) New containerized diesel generation unit on a new site; and/or,
   c) Other alternative(s) based on each community requirements/input.

The BPWG also assessed options for potential ownership and/or operation of the DGS. Remotes was identified as the recommended operator for the following reasons:

- Remotes currently owns/operates diesel generation stations and/or local distribution systems in 10 of the 16 Connecting Communities, and will own/operate the local distribution systems in the remaining six communities prior to grid connection;
- There are efficiencies and economies of scale of having a single operator for backup power in the Connecting Communities;
- Remotes is a provincially regulated utility with operating and performance standards;
- Remotes is best positioned to access provincial subsidies (e.g. Rural or Remote Electricity Rate Protection (RRRP) program) to support costs associated with providing backup power; and
- There are significant costs and requirements that need to be met prior to becoming a licensed generator/distributor in Ontario.

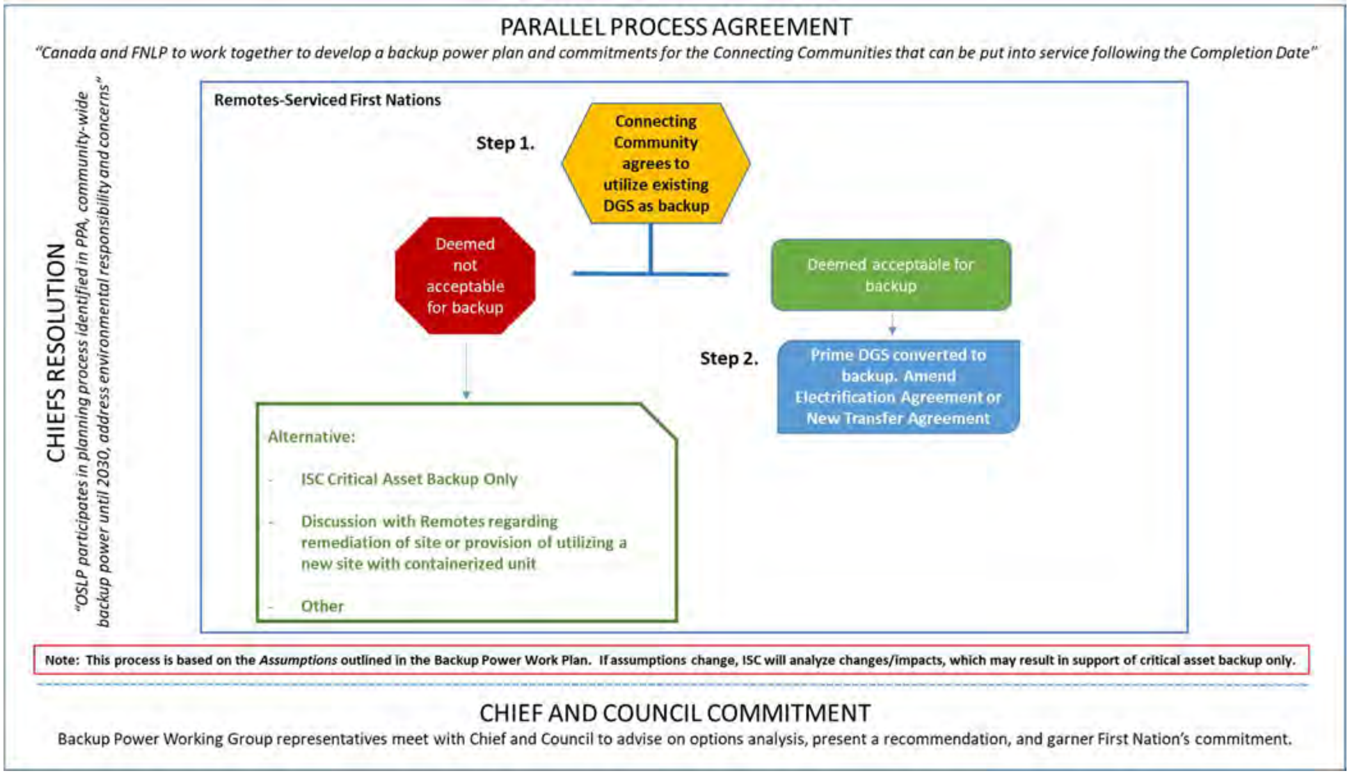
The BPWG engaged Remotes in the analysis of the technical and environmental considerations for re-purposing DGS assets for backup power. The following considerations were noted:

1. For communities where Remotes already owns and operates the DGS, the decision process was simplified since Remotes indicated that, in most instances, there are minimal changes required to convert its DGS from prime power to backup power.
2. For the IPA communities, Remotes would need to assess whether the DGS meets the technical and environmental requirements for re-purposing as backup power.
3. For all communities, the First Nation would need to agree to utilizing the existing DGS for backup power.

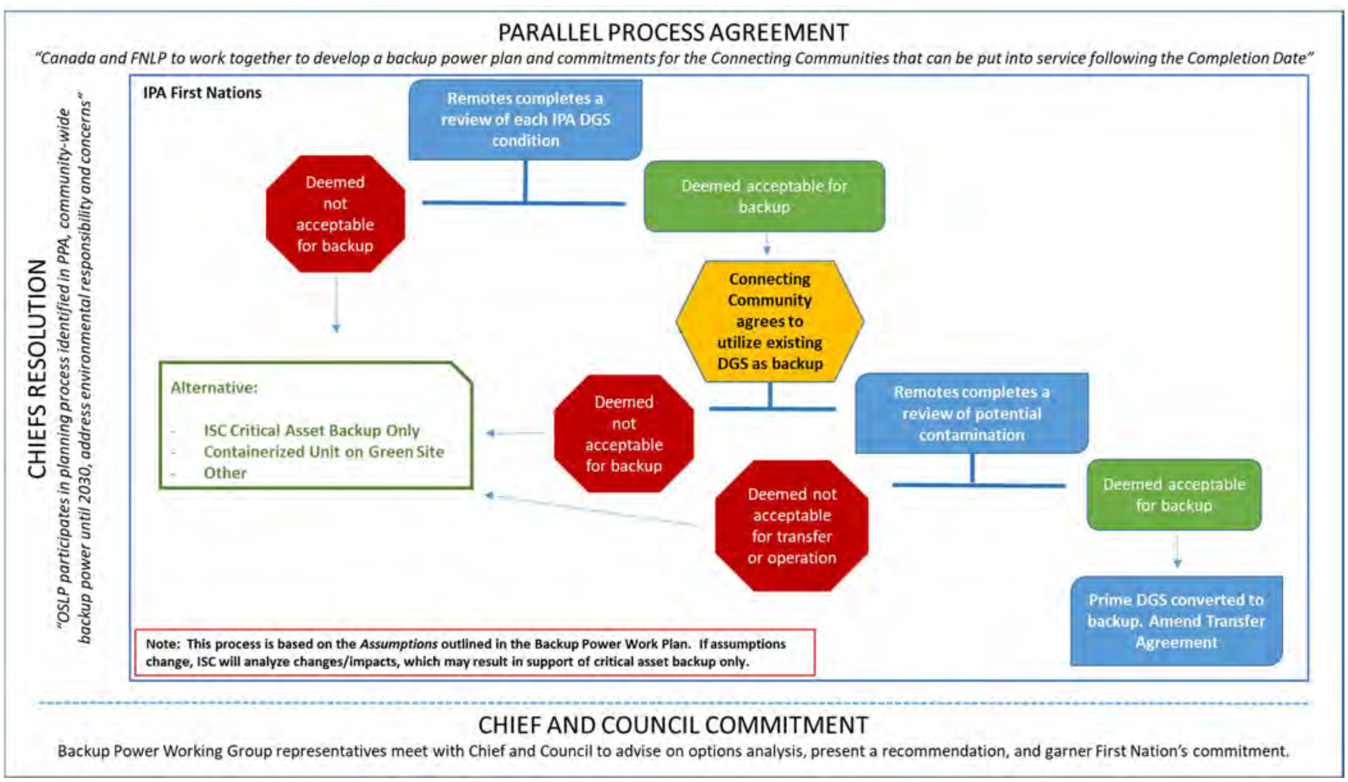
The following illustrations show the options analysis process according to whether a community's DGS is currently owned/operated by Remotes or an IPA:

Page 606 of 798

REMOTES COMMUNITIES: Process for Determining Whether DGS can be Re-Purposed



IPA COMMUNITIES: Process for Determining Whether DGS can be Re-Purposed



Page 607 of 798

6.1. Re-Purposing Existing Diesel Generators

Remotes Report-2018 indicated that, from a technical perspective, most of the 16 existing DGS facilities can be re-purposed for backup power, with the exception of Pikangikum First Nation and Wawakapewin First Nation. Prior to takeover of any IPA DGS, it must be in good operating condition and be in compliance with all applicable industry standards and regulations.

As the Remotes Report-2018 did not include environmental considerations, the BPWG provided environmental documentation on the IPA DGS sites to Remotes in order for them to identify any environmental concerns and requirements for takeover. Remotes indicated there are environmental concerns for all IPA First Nations, and that further environmental studies may be required. Remotes stated that they will not accept any liability for environmental contamination that occurred prior to their takeover of operations. As such, an agreement would need to be reached between Remotes, the First Nation and Canada to outline environmental responsibility for pre-existing contamination, as well as any new contaminations that may occur after Remotes takeover. Remotes also noted they would not accept transfer of ownership of the IPA assets due to the current backup term set to end in 2030; however, they are willing to operate the IPA DGS sites, assuming an agreement ("Operating Agreement") on the terms and conditions can be reached among relevant parties.

In November 2019, Remotes prepared a Containerized DGS Option Annex ("Remotes Report-Annex"), which advised that North Caribou Lake First Nation's diesel generating station is at end of life and the site has significant contamination that requires cleanup. Remotes stated that they will not operate on the existing site after grid connection; therefore, costing to build an asset on a new site within North Caribou Lake First Nation was included in their Containerized DGS Option Annex.

During Round 1 (2019) of community engagement sessions conducted by Opiikapawiin, Keewaywin First Nation indicated their concerns with utilizing their existing DGS assets for backup power due to its current location. North Caribou Lake First Nation indicated that they do not support utilizing their existing DGS assets for backup power due to the existing soil contamination.

Page 608 of 798

Table 4 below shows a summary of the BPWG's assessment on re-purposing the existing DGS in the Connecting Communities, based on the analysis completed by Remotes and community engagement:

Table 4 - Summary Table on Re-Purposing an Existing DGS

First Nation	Current LDC	Technically Feasible to Remotes[1]	Environmentally Acceptable to Remotes	Re-purposing Acceptable to First Nation[2]
Bearskin Lake	Remotes	Yes	Yes	Yes
Deer Lake	Remotes	Yes	Yes	Yes
Kasabonika Lake	Remotes	Yes	Yes	Yes
Kingfisher Lake	Remotes	Yes	Yes	Yes
Kitchenuhmaykoosib Inninuwug	Remotes	Yes	Yes	Yes
North Caribou Lake[3]	Remotes	No[3]	N/A	No
Pikangikum	Remotes	N/A, DGS is being decommissioned		
Sachigo Lake	Remotes	Yes	Yes	Yes
Sandy Lake	Remotes	Yes	Yes	Yes
Wapekeka	Remotes	Yes	Yes	Yes
Keewaywin	IPA	Yes	TBD[4]	Unknown[5]
Muskrat Dam	IPA	Yes	TBD[4]	Yes
North Spirit Lake	IPA	Yes	TBD[4]	Yes
Poplar Hill	IPA	Yes	TBD[4]	Yes
Wawakapewin	IPA	No	N/A	N/A
Wunnumin Lake	IPA	Yes	TBD[4]	Yes

Notes:

1. Hydro One Remote Communities Inc. December 2018 report entitled "Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities".
2. OSLP's Community Engagement Sessions - Round 1 & 2.
3. As per Remotes letter, dated March 2020, North Caribou Lake First Nation's DGS is not technically feasible.
4. Discussions underway between Remotes and ISC to finalize an agreement related to environmental responsibilities pending Environmental Site Assessments results.
5. OSLP engagement with First Nation is on-going.

Page 609 of 798

Table 5 summarizes Remotes estimated costs to transition the existing DGS assets from prime to backup power service in Connecting Communities, as well as ISC's desktop analysis of the costs to ensure ISC-funded health and safety critical assets have dedicated standby backup power:

Table 5 - Estimated Capital Costs to Re-purpose an Existing DGS			
First Nation	**Transitional Capital Support[2]**	**Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs[4]**	**Total Estimated Costs**
Bearskin Lake	$118,000	$122,400	**$240,400**
Deer Lake	$118,000	$391,200	**$509,200**
Kasabonika Lake	$118,000	$150,400	**$268,400**
Kingfisher Lake	$118,000	$150,400	**$268,400**
Kitchenuhmaykoosib Inninuwug	$118,000	$234,400	**$352,400**
Sachigo Lake	$118,000	$150,400	**$268,400**
Sandy Lake	$118,000	$234,400	**$352,400**
Wapekeka	$118,000	$178,400	**$296,400**
Keewaywin[3]	$684,000	$234,400	**$918,400**
Muskrat Dam[3]	$199,000	$178,400	**$377,400**
North Spirit Lake[3]	$209,000	$335,200	**$544,200**
Poplar Hill[3]	$199,000	$279,200	**$478,200**
Wunnumin Lake[3]	$209,000	$150,400	**$359,400**
Totals	$2,444,000	$2,789,600	$5,233,600
Notes:			
1. Cost estimates are in 2019$.			
2. Hydro One Remote Communities Inc. December 2018 report entitled "Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities" and Hydro One Remote Communities Inc. November 2019 report entitled "Containerized DGS Option Annex".			
3. Operator Training ($43,000) has been removed from the above Transitional Capital Support costs and captured under O&M costs in Table 9.			
4. ISC Desktop Analysis of Health & Safety ISC-Critical Assets (GCDocs#36929572).			

Note: For the IPA communities identified as technically feasible for Remotes to operate in Table 4, further discussions by Remotes and ISC are underway to determine if an agreement related to environmental responsibilities can be reached. Any such agreement terms will be reflected in the Operating Agreement between Remotes, the IPA First Nation, and Canada (see Section 7.1.2 Environmental).

Page 610 of 798

Advantages / Disadvantages of Re-Purposing DGS for Backup Power

Advantages	Disadvantages
• Lowest initial cost option (for most, but not all communities) • Utilizes an existing asset • Sufficient output capacity to provide full community backup to 2030 at a minimum • For Remotes communities, lowest implementation risk	• Does not allow for full clean-up of contaminated DGS sites in the near term • May face implementation delays in IPA communities where ISC / FN / Remotes agreement required on environmental responsibility • Cost risk to ensure DGS meets industry standards and regulations • Remaining life of assets shorter than a new DGS

6.2. Containerized Diesel Generators Alternative

To deepen the backup power analysis, the BPWG (through Opiikapawiin) engaged Remotes to determine the cost and requirements for containerized diesel generation assets on new sites for the IPA Communities, Pikangikum First Nation and North Caribou Lake First Nation, since there are either technical and/or environmental challenges to re-purposing those diesel generating stations. At the request of the BPWG, gensets and fuel tanks were sized to be sufficient until at least 2030 (based on 4% annual growth). Remotes Report-Annex on the Containerized DGS Option can be found in Appendix D.

The Annex provides the following:

- Costs to install a new backup generating station on a new site in each of the IPA communities, North Caribou Lake First Nation, and Pikangikum First Nation;
- Nominal generator sizing and other requirements for major components of the generating stations; and
- Sample layout for a containerized backup power facility within a Remotes compound site.

For costing purposes, Remotes assumed that the containerized diesel generation facility would be located on the same site as the Remotes Compound[2]. The capital cost estimates include permitting, contract management, project management, partial design, and a 10% contingency.

[2] Except Pikangikum First Nation, where a new or expanded Remotes site would be required

Page 611 of 798

Table 6 provides the Remotes estimated capital costs for a new DGS, as well as ISC's desktop analysis of the costs to address current gaps that will ensure that ISC-funded health and safety critical assets have dedicated standby backup power:

Table 6 - Estimated Capital Costs for New Containerized DGS Alternative

First Nation	Estimated Capital Cost for New Containerized Diesel Generator[2]	Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs[3]	Total Estimated Costs
North Caribou Lake	$3,903,900	$206,400	**$4,110,300**
Pikangikum	$5,848,700	$122,400	**$5,971,100**
Keewaywin	$3,568,400	$122,400	**$3,690,800**
Muskrat Dam	$3,568,400	$178,400	**$3,746,800**
North Spirit Lake	$3,568,400	$335,200	**$3,903,600**
Poplar Hill	$3,568,400	$279,200	**$3,847,600**
Wawakapewin	$2,901,800	$0	**$2,901,800**
Wunnumin Lake	$4,299,900	$150,400	**$4,450,300**
Totals	$31,227,900	$1,394,400	$32,622,300

Notes:

1. Cost estimates are in 2019$.
2. Hydro One Remote Communities Inc. November 2019 report entitled "Containerized DGS Option Annex".
3. ISC Desktop Analysis of Health & Safety ISC-Critical Assets (GCDocs#36929572).

Advantages / Disadvantages of New Containerized DGS Alternative

Advantages	Disadvantages
• Provides full community backup to 2030 at a minimum • Allows for decommissioning and full clean-up of contaminated DGS sites • Major components include a manufacturer's warranty • Longer asset life expected compared to re-purposing a DGS	• Highest cost option for the term to 2030 • Requires a new or expanded site (in most cases), which may add to construction timelines due to site selection and environmental assessment requirements • More implementation risks, including lead times, winter road availability, and permitting requirements

Page 612 of 798

6.3. ISC-Critical Asset Backup Only Alternative

ISC's LOSS for Electric Power Supply and Distribution Systems supports backup power for the following ISC-funded critical assets when reliability concerns are demonstrated, and funding is available:

1. Water treatment plants;
2. Wastewater treatment plants & related lift stations;
3. Schools;
4. Nursing stations & nurse residences; and
5. Fire halls.

Under the scenario where full community backup is available, additional capital for backup at the school and fire hall would be avoided since Remotes' historical local distribution reliability has been 99.92%. In 2019, ISC conducted a desktop analysis to determine where additional capital would be required to fulfill its LOSS, based on existing community assets.

Table 7 provides ISC's estimated costs, as well as the avoidable portion under the scenario where full community backup is available:

Table 7 - Estimated Costs for Backup Power Gaps in ISC-Funded Critical Assets Alternative								
	Health & Safety ISC-Critical Assets					**Other ISC-Funded Assets**		
First Nation	**Water Treatment**	**Sewage Treatment**	**Sewage Lift Stations**	**Nursing Station/ Residence**	**Estimated Cost to Fill Gaps**	**School**	**Fire Hall**	**Total Estimated Cost to Fill Critical Asset Gaps**
Bearskin Lake	No Gap	No Gap	$122,400	No Gap	**$122,400**	$784,000	$156,800	**$1,063,200**
Deer Lake	No Gap	$156,800	$234,400	No Gap	**$391,200**	No Gap	No Asset	**$391,200**
Kasabonika Lake	No Gap	No Gap	$150,400	No Gap	**$150,400**	$784,000	No Asset	**$934,400**
Kingfisher	No Gap	No Gap	$150,400	No Gap	**$150,400**	$784,000	$156,800	**$1,091,200**
Kitchenuhmaykoosib Inninuwug	No Gap	No Gap	$234,400	No Gap	**$234,400**	No Gap	No Asset	**$234,400**
North Caribou Lake	No Gap	No Gap	$206,400	No Gap	**$206,400**	$784,000	$156,800	**$1,147,200**
Pikangikum	No Gap	No Gap	$122,400	No Gap	**$122,400**	No Gap	No Asset	**$122,400**
Sachigo Lake	No Gap	No Gap	$178,400	No Gap	**$178,400**	$784,000	$156,800	**$1,119,200**
Sandy Lake	No Gap	No Gap	$150,400	No Gap	**$150,400**	No Gap	$156,800	**$307,200**
Wapekeka	No Gap	No Gap	$150,400	No Gap	**$150,400**	$784,000	No Asset	**$934,400**
Keewaywin	No Gap	No Gap	$122,400	No Gap	**$122,400**	$784,000	$156,800	**$1,063,200**
Muskrat Dam	No Gap	No Gap	$178,400	No Gap	**$178,400**	$784,000	$156,800	**$1,119,200**
North Spirit Lake	No Gap	$156,800	$178,400	No Gap	**$335,200**	$784,000	No Asset	**$1,119,200**
Poplar Hill	No Gap	$156,800	$122,400	No Gap	**$279,200**	$784,000	No Asset	**$1,063,200**
Wawakapewin	No Gap	No Asset	No Asset	No Gap	**$0**	No Asset	No Asset	**$0**
Wunnumin Lake	No Gap	No Gap	$150,400	No Gap	**$150,400**	$784,000	No Asset	**$934,400**
Totals	$0	$470,400	$2,452,000	$0		$8,624,000	$1,097,600	
ISC Critical Asset Gap								**$12,644,000**
Avoidable Capital if Full Community Backup Available (School & Fire Hall)								**$9,721,600**
Source: ISC Desktop Analysis of ISC-Critical Assets (GCDocs#36929572).								

Page 613 of 798

Advantages / Disadvantages of ISC-Funded Critical Asset Backup Alternative

Advantages	Disadvantages
• Allows for decommissioning and full clean-up of contaminated DGS sites • May be quickest option to implement	• Does not meet FNLP Resolution position calling for full community backup to 2030 at a minimum

7.1. Implementation Requirements for the Options

Each of the backup power options being considered have different implementation requirements, described in the table below. These requirements add varying costs, as well as implementation risks (discussed later in the Plan).

7.1.1. Legal

Agreement	Applicable Option(s)	Description / Comments
Electrification Agreement or Operating Agreement	• Re-purposing an IPA DGS • Re-purposing a Remotes DGS • New Containerized DGS	• Electrification/Operating Agreements will be between the First Nation, Remotes and Canada, and will set out the terms and conditions (including funding and environmental responsibility) for the provision of backup power on reserve
Section 28(2) Permit and/or Land Use Permit	• All except ISC-Funded Critical Asset Backup Alternative	• Remotes will need access to reserve land for the provision of backup power; therefore, a Section 28(2) permit will need to be issued by Canada • Even with existing Remotes sites, a Section 28(2) permit may not currently be in place • If the DGS is located off reserve, then a Land Use Permit issued by Ontario's Ministry of Natural Resources and Forestry (MNRF) will be required (and land users may be impacted, which may require consideration) • Both permits require a survey and an environmental review • The permits will outline environmental responsibilities of the permittee
Band Council Resolution (BCR)	• All	• For the agreements and permits identified above, an executed Band Council Resolution will be required

Page 614 of 798

7.1.2. Environmental

Activity	Applicable Option(s)	Description / Comments
Phase II Environmental Site Assessment (ESA)	• Re-purposing an IPA DGS • New Containerized DGS	• Identify the extent of contamination and provide a baseline that could be used in order to determine environmental responsibility pre- and post-transfer of ownership/operations to Remotes • ESA report will include recommendations on how to address and/or mitigate impacts • A Phase III ESA may be required in certain communities depending on the recommendations from the Phase II ESA
Confirming Environmental Responsibility and/or Site Remediation	• Re-purposing an IPA DGS • New Containerized DGS	• Remotes will not accept responsibility for contaminations that occurred prior to their takeover of DGS operations. Based on the ESAs, Operating Agreements may reflect one or more of the following: 1. Actions to address the contamination (e.g. clean up, capping, etc.); 2. Remotes being released from any liabilities associated with contaminations that occurred prior to Remotes takeover; and 3. Agreement on responsibility should contaminations occur after Remotes takeover. • If there is extensive contamination at an IPA DGS site, it may be difficult to complete full remediation prior to the grid connection date
Decommissioning DGS and Site Remediation	• End of life of asset	• If a DGS site is re-purposed, the DGS will be decommissioned and the site remediated when backup power is no longer required. • If a new site is used, the existing DGS site will be decommissioned and remediated; the new containerized unit will be decommissioned, and the site remediated when backup power is no longer required.

7.1.3. Proponent & Funding Process for Transitional Capital Costs

Process	Applicable Option(s)	Description / Comments
Upgrades by Remotes	• Re-purposing a Remotes DGS	• Remotes has provided the scope of required upgrades in order for an existing Remotes DGS to be re-purposed for backup power • Remotes would complete the required upgrades under a funding agreement with the First Nation • The First Nation would apply for this funding under ISC's Capital Facilities and Maintenance Program (CFMP)
Upgrades through a First Nation Capital Project	• Re-purposing an IPA DGS • New Containerized DGS	• With IPA DGS sites, the project proponent would be the First Nation and the project would be managed under

Page 615 of 798

		ISC's Capital Facilities and Maintenance Program (CFMP). • Note for New Containerized DGS: if objective is to locate it at the proposed Remotes Compound site being constructed through the IPA Upgrades project that is currently underway, then the First Nation will need to consider the synergies of coordinating or combining the backup power project with the IPA local distribution upgrades and transfer process • Remotes would be engaged throughout the project, as needed
Upgrades through a First Nation Capital Project	• Critical Asset Backup	• In both IPA and Remotes-serviced communities, the First Nation would be the project proponent for any funding provided for dedicated standby generators at ISC-funded critical assets • The project would be managed under ISC's Capital Facilities and Maintenance Program (CFMP)

7.1.4. Regulatory

Activity	Applicable Option(s)	Description / Comments

Provincial Regulatory Approval	• Re-purposing an IPA DGS
	• Re-purposing a Remotes DGS
	• New Containerized DGS
		• Remotes' license will need to be amended by the OEB to add the IPA community names to its service territory to allow for the generation and distribution of diesel for backup power purposes
		• Remotes will apply to the provincial regulator, the OEB, to recover any costs for the provision of backup service (through the Rural or Remote Rate Electricity Rate Protection (RRRP) program) on their next rate filing, which is in 2023
		  ○ Reliability, customer-defined need, First Nation/community impact, re-use of assets, ISC funding vs. costs/ratepayer impact will be considered by the OEB
		  ○ Appendix J of the Plan provides examples of backup power investments that have been accepted in the past by the OEB; however, it is important to note that each example is situation-specific and they do not bind the OEB's future rulings with regard to backup power

Page 616 of 798

7.1.5. Estimated Implementation Costs for the Options

In addition to the capital costs for each option, it is important to assess the required implementation costs for each option. Based on the implementation requirements described above, Table 8 provides the estimated implementation costs (based on a review of other ISC-funded projects) for each option:

Table 8 - Estimated Implementation Costs

	Remotes Community *(Re-purpose DGS)*	**IPA Community *(Re-purpose DGS)***	**(*Containerized DGS*)**	**Critical Asset Backup Only**
Legal				
Asset Transfer Agreement (Understanding and Conveyance Agreement) or Electrification Agreement	$10,000	N/A	$20,000	N/A
Operating Agreement	N/A	$20,000	N/A	N/A
Section 28(2) or Land Use Permit	$10,000	$10,000	$10,000	N/A
Environmental				
Environmental Site Assessment (Phase I, II, III)[1]	N/A	$300,000	$60,000	N/A
Allowance for Implementation of ESA Recommendations (Phase II, III)[2]	N/A	$300,000	$0	N/A
Proponent & Funding Process				
Capital Project Soft Costs (Project Mgt, Eng)[3,4,5]	N/A	$50,000	$300,000	$100,000
Regulatory				
Remotes to include in 2023 rate filing	$0	$0	$0	N/A
Total Implementation Cost (per community)	**$20,000**	**$680,000**	**$390,000**	**$100,000**

Notes:

1. Assumes 50/50 cost sharing with IPA transfer project for containerized DGS.
2. Final results of the Environmental Site Assessment (Phase II, III) will identify recommendations; $300,000 cost estimate for planning purposes only.
3. $50,000: Approximately 20% of average capital cost (engineering, project management, First Nation coordination (1.0%-1.5%), tender & contract administration, technical support).
4. $300,000: Approximately 10% of average capital cost for First Nation Coordination (1.0%-1.5%), Project Management, financial management, final engineering, tender & contract administration, technical support, and site selection costs (some engineering covered under the Remotes cost estimate).
5. Actual cost based on competitively procuring a Professional Project Manager and Engineering; $100,000 cost estimate for planning purposes only. Note, Pikangikum First Nation's cost estimate reduced to $12,500 based on estimated cost of filling backup power gap.

Page 617 of 798

7.2. DGS Operations & Maintenance Costs to 2030

In addition to capital and implementation costs, it is important to assess the expected operations & maintenance (O&M) costs for each option. Remotes provided estimates for O&M costs of providing backup power. The BPWG used 2030 as the period for assessing these costs as it aligns with the FNLP Shareholders Resolution that calls for community-wide backup power until 2030 at a minimum. This timeline will also allow for sufficient time to assess the real-life outages in a grid-connected environment. However, the Remotes Report-2018 indicated that most assets would be sufficient to provide backup power beyond 2030.

Remotes' estimates for annual non-fuel O&M costs reflect the following considerations:

- The stations could be run remotely, but some operational aspects would still require the on-site presence and expertise of a local operator
- Thorough yearly inspection and maintenance (two weeks every year per station) would be required
- All genets and auxiliary equipment would be run unloaded for approximately 1.5 hours every month
- Regular operator training would be required

In their Remotes Report-2018, Remotes identified the DGS Backup Power Operator position, approximately 20 hours per week, as an opportunity for local employment associated with a backup station.

Remotes estimated the fuel requirements for each community, accounting for testing fuel, fuel for transmission outages (based on an average load equal to 70% of the community peak demand), and contingency fuel for a 5-day outage in January (based on an average load equal to 85% of the community peak demand).

Page 618 of 798

Table 9 provides a summary of Remotes estimated O&M costs to re-purpose a DGS to provide backup power until 2030:

Table 9 - Estimated O&M Costs to Re-Purpose DGS, when Technically Feasible, until 2030			
First Nation	**Non-Fuel O&M to 2030**	**Fuel to 2030**	**Total O&M/Fuel to 2030**
Bearskin Lake	$1,575,000	$192,108	**$1,767,108**
Deer Lake	$2,025,000	$296,055	**$2,321,055**
Kasabonika Lake	$1,575,000	$313,203	**$1,888,203**
Kingfisher Lake	$2,025,000	$177,541	**$2,202,541**
Kitchenuhmaykoosib Inninuwug	$2,025,000	$350,161	**$2,375,161**
Sachigo Lake	$1,575,000	$206,469	**$1,781,469**
Sandy Lake	$1,800,000	$612,953	**$2,412,953**
Wapekeka	$1,575,000	$166,026	**$1,741,026**
Keewaywin[2]	$1,501,000	$176,424	**$1,677,424**
Muskrat Dam[2]	$1,501,000	$203,496	**$1,704,496**
North Spirit Lake[2]	$1,501,000	$148,790	**$1,649,790**
Poplar Hill[2]	$1,684,000	$176,872	**$1,860,872**
Wunnumin Lake[2]	$1,684,000	$322,226	**$2,006,226**
Notes:			
1. Cost estimates are in 2019$.			
2. Operator Training cost has been added to 'Non-Fuel O&M to 2030' amounts and removed from the 'Transitional Capital Support' amounts in Table 5.			
Source: Hydro One Remote Communities Inc. November 2019 report entitled "'ontainerized DGS Option Annex".			

Table 10 provides a summary of Remotes estimated O&M costs to operate a containerized DGS until 2030:

Table 10 - Estimated O&M Costs for Containerized Unit until 2030					
First Nation	**Non-Fuel O&M to 2030**	**Fuel to 2030**	**Total O&M/Fuel to 2030**	**Operator Training**	**Total O&M Costs to 2030**
North Caribou Lake	$1,641,000	$295,823	**$1,936,823**	$43,000	**$1,979,823**
Pikangikum	$1,641,000	$353,863	**$1,994,863**	$43,000	**$2,037,863**
Keewaywin	$1,457,000	$176,424	**$1,633,424**	$44,000	**$1,677,424**
Muskrat Dam	$1,457,000	$203,496	**$1,660,496**	$44,000	**$1,704,496**
North Spirit Lake	$1,457,000	$148,790	**$1,605,790**	$44,000	**$1,649,790**
Poplar Hill	$1,641,000	$176,872	**$1,817,872**	$43,000	**$1,860,872**
Wawakapewin	$1,457,000	$58,149	**$1,515,149**	$44,000	**$1,559,149**
Wunnumin Lake	$1,641,000	$322,226	**$1,963,226**	$43,000	**$2,006,226**
Notes:					
1. Cost estimates are in 2019$.					
Source: Hydro One Remote Communities Inc. November 2019 report entitled "Containerized DGS Option Annex".					

Note: Cost difference between re-purposing an existing DGS and a new containerized unit is related to the addition of Operator Training costs within the Containerized Unit option.

7.3. Critical Asset Backup Only

Backup power generators are considered to be a component of the existing asset (e.g., water treatment plant) and covered under ISC's formula generated O&M funding allocation for that particular asset. There would not be any incremental O&M support above the formula generated amount for assets that have backup power generators installed.

Page 620 of 798

8. Summary of Options for Each Connecting Community

8.1. Cost Comparison

The following cost comparison shows a summary of all the expected costs for each option to 2030:

Re-Purpose Existing DGS for Backup Power within Remote-Serviced Communities					
Remotes-Serviced Connecting Communities	**Initial Capital Costs**	**Implementation Costs**	**Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs**	**O&M and Fuel Costs**	**Total Costs**
Bearskin Lake	$118,000	$20,000	$122,400	$1,767,108	$2,027,508
Deer Lake	$118,000	$20,000	$391,200	$2,321,055	$2,850,255
Kasabonika Lake	$118,000	$20,000	$150,400	$1,888,203	$2,176,603
Kingfisher Lake	$118,000	$20,000	$150,400	$2,202,541	$2,490,941
Kitchenuhmaykoosib Inninuwug	$118,000	$20,000	$234,400	$2,375,161	$2,747,561
Sachigo Lake	$118,000	$20,000	$178,400	$1,781,469	$2,097,869
Sandy Lake	$118,000	$20,000	$150,400	$2,412,953	$2,701,353
Wapekeka	$118,000	$20,000	$150,400	$1,741,026	$2,029,426

North Caribou Lake First Nation					
Options	**Initial Capital Costs**	**Implementation Costs**	**Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs**	**O&M and Fuel Costs**	**Total Costs**
Containerized DGS on Greenfield Site	$3,903,900	$390,000	$206,400	$1,979,823	$6,480,123
ISC Critical Assets Backup Power Gap	N/A	$100,000	1,147,200	N/A	$1,247,200

Pikangikum First Nation					
Options	**Initial Capital Costs**	**Implementation Costs**	**Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs**	**O&M and Fuel Costs**	**Total Costs**
Containerized DGS on Greenfield Site	$5,848,700	$390,000	$122,400	$2,037,863	$8,398,963
ISC Critical Assets Backup Power Gap	N/A	$12,500	$122,400	N/A	$134,900

Keewaywin First Nation						
Options	**Initial Capital Costs**	**IPA Compliance/ Industry Standard**	**Implementation Costs**	**Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs**	**O&M and Fuel Costs**	**Total Costs**
Re-Purpose Existing DGS for Backup Power	$684,000	$300,000	$680,000	$122,400	$1,677,424	$3,463,824
Containerized DGS on Greenfield Site	$3,568,400	N/A	$390,000	$122,400	$1,677,424	$5,758,224
ISC Critical Assets Backup Power Gap	N/A	N/A	$100,000	1,063,200	N/A	$1,163,200

Page 621 of 798

Muskrat Dam First Nation						
Options	Initial Capital Costs	IPA Compliance/ Industry Standard	Implementation Costs	Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs	O&M and Fuel Costs	Total Costs
Re-Purpose Existing DGS for Backup Power	$199,000	$300,000	$680,000	$178,400	$1,704,496	$3,061,896
Containerized DGS on Greenfield Site	$3,568,400	N/A	$390,000	$178,400	$1,704,496	$5,841,296
ISC Critical Assets Backup Power Gap	N/A	N/A	$100,000	1,119,200	N/A	$1,219,200

North Spirit Lake First Nation						
Options	Initial Capital Costs	IPA Compliance/ Industry Standard	Implementation Costs	Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs	O&M and Fuel Costs	Total Costs
Re-Purpose Existing DGS for Backup Power	$209,000	$300,000	$680,000	$335,200	$1,649,790	$3,173,990
Containerized DGS on Greenfield Site	$3,568,400	N/A	$390,000	$335,200	$1,649,790	$5,943,390
ISC Critical Assets Backup Power Gap	N/A	N/A	$100,000	1,119,200	N/A	$1,219,200

Poplar Hill First Nation						
Options	Initial Capital Costs	IPA Compliance/ Industry Standard	Implementation Costs	Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs	O&M and Fuel Costs	Total Costs
Re-Purpose Existing DGS for Backup Power	$199,000	$300,000	$680,000	$279,200	$1,860,872	$3,319,072
Containerized DGS on Greenfield Site	$3,568,400	N/A	$390,000	$279,200	$1,860,872	$6,098,472
ISC Critical Assets Backup Power Gap	N/A	N/A	$100,000	1,063,200	N/A	$1,163,200

Wawakapewin First Nation						
Options	Initial Capital Costs	IPA Compliance/ Industry Standard	Implementation Costs	Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs	O&M and Fuel Costs	Total Costs
Containerized DGS on Greenfield Site	$2,901,800	N/A	$390,000	$0	$1,559,149	$4,850,949
ISC Critical Assets Backup Power Gap	N/A	N/A	$0	$0	N/A	$0

Wunnumin Lake First Nation						
Options	Initial Capital Costs	IPA Compliance/ Industry Standard	Implementation Costs	Existing Gaps in Health & Safety ISC-Critical Assets - Estimated Costs	O&M and Fuel Costs	Total Costs
Re-Purpose Existing DGS for Backup Power	$209,000	$300,000	$680,000	$150,400	$2,006,226	$3,345,626
Containerized DGS on Greenfield Site	$4,299,900	N/A	$390,000	$150,400	$2,006,226	$6,846,526
ISC Critical Assets Backup Power Gap	N/A	N/A	$100,000	934,400	N/A	$1,034,400

Page 622 of 798

9. Funding & Support

9.1. Backup Power and Reliability Under Ontario Energy Regulation

The OEB and IESO work with electricity transmission, distribution and generation companies to support energy sustainability and reliability. There are a few recent precedents in Ontario where costs associated with improving transmission system reliability have been approved by the OEB, some of which include First Nation communities located in remote areas of the province:

- Five Nations Energy
- Anwaatin
- Pelee Island

In a grid-connected environment, the Connecting Communities will be able to advocate for improvements that result in increased reliability of service.

Additional information related to these situations can be found in Appendix J.

9.2. First Nations Support

The BPWG, working with Opiikapawiin's legal counsel (Ericksons LLP), Remotes, and respective Tribal Councils, has drafted a BCR, which can be used by Chief and Council to confirm support of repurposing their community's current generation assets to provide community-wide backup power until the end of 2030. A draft of each BCR, one for Remotes-serviced communities and one for IPA communities, can be found in Appendix K.

For Pikangikum, North Caribou Lake, and Wawakapewin First Nations, a BCR will be required during the implementation stage to indicate the First Nation's support of having a standby backup power source available at each ISC-funded critical asset.

9.3. ISC Considerations for Supporting Backup Power

Through discussions with communities and project partners, ISC has indicated the department is aware that the Connecting Communities are seeking community-wide backup power, until 2030 as a minimum. ISC has also learned that, due to varying situations and preferences, a community-by-community approach should be taken.

ISC has indicated the department is supportive of working collaboratively toward this vision based on the following considerations:

- Where technically feasible, and with no existing critical health, safety and environmental risks, the prime power DGS should be utilized for backup power purposes.
- If community-wide backup power is being provided, it is always operated by an OEB-licensed generator (e.g. Remotes).
- Each community provides an executed Band Council Resolution confirming their support for the backup power approach to be taken in their community.

Page 623 of 798

- Where existing DGS equipment is utilized for backup power purposes, operations & maintenance and replacement capital costs, post-transfer, will be the full responsibility of the OEB-licensed generator.
- Any community-wide backup power arrangement is incorporated into the First Nation's Electrification Agreement/Operating Agreement with Remotes and is valid until at least December 31, 2030. Should a signatory to the agreement seek to terminate the agreement early, another provincially licensed and regulated local distribution company is selected to assume operations until the 2030 timeline is reached. All associated costs related to the termination and assuming of operations by another party will not be the responsibility of ISC.
- Communities agree that backup power for critical infrastructure, specifically school facilities (or other emergency gathering point(s)) and fire halls, will not be required or funded by ISC when centralized backup is in place. However, ISC is committed to ensuring that there is also critical asset backup power at water and wastewater facilities (including lift stations), the nursing station, and nursing residences.
- Where existing DGS equipment cannot be utilized for backup power purposes, at a minimum, ISC will work with the community to facilitate backup power for ISC-funded critical community assets (refer to Section 6.3).
- Any funds provided by ISC for backup power (critical asset only or community-wide) will be delivered through the Capital Facilities and Maintenance Program and be subject to its policies and directives, with the goal of having backup power in place at the time of the community's connection to the provincial grid.

ISC is also in agreement to meet with the First Nation, Remotes, and Ontario prior to 2030 to analyze the demonstrated need for backup power within each Connecting Community going forward.

9.4. Remotes Support

Remotes has been an active participant in the BPWG and recognizes that communal backup power will enhance reliability, mitigate health and safety concerns as well as protect community assets; therefore, Remotes supports the implementation of backup power until 2030.

At the request of Opiikapawiin, Remotes has provided two reports "Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connecting Communities" report ("Remotes Report-2018), dated December 2018, and the Containerized DGS Option Annex ("Remotes Report-Annex"), dated November 2019. Both reports provided insight and analysis into the potential backup power in connecting communities.

In their letter to Opiikapawiin, dated May 8, 2020, see Appendix I, Remotes indicated that for the existing Remotes served communities, with the exception of North Caribou, Remotes supports the re-use of existing Remotes generation facilities as backup power. The existing Remotes assets continue to have long-term importance in supporting power reliability to the communities.

For the Independent Power Authority communities of Poplar Hill, North Spirit Lake, Keewaywin, Wunnumin, and Muskrat Dam, Remotes has indicated support in re-purposing the existing generators and provide community backup power until 2030, provided the following conditions are met:

- Fixed-term Operating Agreement signed by Remotes, First Nation, and Indigenous Services Canada;

Page 624 of 798

- IPA diesel generating stations be in sound operating condition and compliant with applicable law, regulations and standards;
- Remotes will not be responsible for all transitional costs to achieve sound operating condition and compliance related to re-purposing the DGS for backup power purposes;
- An Environmental Site Assessment will be conducted at or near takeover of the DGS to determine baseline condition of site;
- Remotes will not be responsible for contamination that occurred prior to takeover of DGS operations; and
- Remotes will not be responsible for any capital capacity increases at these sites.

Where conditions are met, Remotes will be responsible for operations, maintenance and any like for like replacement capital costs. Remotes will seek a license amendment from the OEB and through their 2023 rate filing, apply to have costs for the provision of backup service by the Rural or Remote Rate Electricity Protection (RRRP) program. Should the OEB not support the use of the RRRP for these costs, Remotes will be unable to provide backup services.

In situations where a DGS cannot be repurposed to provide backup power services (Pikangikum, North Caribou, and Wawakapewin), Remotes supports either the containerized DGS or the ISC-funded critical community assets only backup options.

After 5 years of full transmission operation, in 2028 or thereabouts, Remotes agrees to meet with the BPWG to review the efficacy of backup power and future funding commitment.

Page 625 of 798

10. Proposed Option for Each Connecting Community Based on Funding Support

Table 11 provides the proposed backup power option for each Connecting Community based on support from both Remotes and ISC:

Table 11. Recommended Option for Each Community

First Nation	Current LDC	Recommended Option	Initial Capital Costs[2]	IPA Compliance/ Industry Standard[4]	Implementation Costs	ISC Health & Safety Critical Assets Backup Gaps	O&M and Fuel Costs to 2030	Total Costs
Bearskin Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$122,400	$1,767,108	**$2,027,508**
Deer Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$391,200	$2,321,055	**$2,850,255**
Kasabonika Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$150,400	$1,888,203	**$2,176,603**
Kingfisher Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$150,400	$2,202,541	**$2,490,941**
Kitchenuhmaykoosib Inninuwug	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$234,400	$2,375,161	**$2,747,561**
North Caribou Lake[3]	Remotes	Critical Asset Only	N/A	N/A	$100,000	$1,147,200	N/A	**$1,247,200**
Pikangikum[3]	Remotes	Critical Asset Only	N/A	N/A	$12,500	$122,400	N/A	**$134,900**
Sachigo Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$178,400	$1,781,469	**$2,097,869**
Sandy Lake	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$150,400	$2,412,953	**$2,701,353**
Wapekeka	Remotes	Re-purpose DGS	$118,000	N/A	$20,000	$150,400	$1,741,026	**$2,029,426**
Keewaywin[5]	IPA	Re-purpose DGS	$684,000	$300,000	$680,000	$122,400	1,677,424	**$3,463,824**
Muskrat Dam[5]	IPA	Re-purpose DGS	$199,000	$300,000	$680,000	$178,400	1,704,496	**$3,061,896**
North Spirit Lake[5]	IPA	Re-purpose DGS	$209,000	$300,000	$680,000	$335,200	1,649,790	**$3,173,990**
Poplar Hill[5]	IPA	Re-purpose DGS	$199,000	$300,000	$680,000	$279,200	1,860,872	**$3,319,072**
Wawakapewin[3,5]	IPA	Critical Asset Only	N/A	N/A	$0	$0	N/A	**$0**
Wunnumin Lake[5]	IPA	Re-purpose DGS	$209,000	$300,000	$680,000	$150,400	2,006,226	**$3,345,626**
		Sub-totals	$2,444,000	$1,500,000	$3,672,500	$3,863,200	$25,388,324	$36,868,024

Notes:

1. Cost estimates are in 2019$.
2. Hydro One Remote Communities Inc. December 2018 report entitled "Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities" and and Hydro One Remote Communities Inc. November 2019 report entitled "Containerized DGS Option Annex".
3. Critical Assets Backup Gaps include all assets within ISC's LOSS; Implementation costs reflect CFMP policies.
4. IPA DGS must be in good operating condition and be in compliance with all applicable industry standards and legal regulations; estimated cost.
5. Operator Training for IPA Communities has been captured within O&M and Fuel Costs to 2030 costs.

<u>Remotes Communities</u>

The recommended option for most Remotes communities is to re-purpose the existing DGS for backup power, since it provides the best value based on the benefits of community-wide backup versus the incremental re-purposing cost.

Pikangikum First Nation no longer has a DGS, and as such, the two options are a new containerized DGS or critical asset backup. The cost for community-wide backup power (a new containerized DGS) is much higher than the critical asset backup option. Based on a cost-benefit analysis, dedicated backup power at ISC-funded critical assets is the recommended option. Compared to communities further north, the risk of outages is less for Pikangikum since it is closer to Red Lake and, therefore, the Ontario transmission network. Some impacts of outages could be reduced if an all-season road is built to Pikangikum.

Page 626 of 798

With respect to North Caribou Lake First Nation, Remotes has indicated that post-grid connection, Remotes will not operate the current DGS as it is at end-of-life and the site has significant contamination that requires cleanup. As such, the two options are a new containerized DGS or critical asset backup. The cost for community-wide backup power (a new containerized DGS) is much higher than the critical asset backup option. Based on a cost-benefit analysis, dedicated backup power at ISC-funded critical assets is the recommended option. North Caribou Lake is a road-connected community, which allows for easier mobilization if a long-term outage occurs. This option will also facilitate Remotes remediating the contamination at the DGS site.

IPA Communities

The recommended option for most IPA communities is to re-purpose the existing DGS for backup power, since it provides the best value based on the benefits of community-wide backup versus the incremental re-purposing cost. In order to implement this option, the parties will need to enter into Operating Agreements and address responsibility for environmental contamination.

As noted in the Remotes Report-2018, from a technical perspective, the existing DGS in Wawakapewin First Nation cannot be re-purposed by Remotes for community-wide backup. The cost for community-wide backup power (a new containerized DGS) is much higher than the critical asset backup option. Based on a cost-benefit analysis, dedicated backup power at ISC-funded critical assets is the recommended option.

Page 627 of 798

11. Implementation Steps

The list below provides the key activities to implement the recommended backup power options. Since the expected connection dates vary by community, a community specific timeline is provided in Appendix A.

For each Connecting Community, the project proponent will be the First Nation, supported by their Tribal Council / Technical Advisors, and, based on availability of funding, transitional capital funding (including Initial Capital Costs, IPA Compliance/Industry Standard Costs and Implementation costs) will be delivered under ISC's Capital Facilities and Maintenance Program (CFMP). The funding approval process will depend on whether the project is considered a minor capital project (<$1.5 million) or major capital project (≥$1.5 million). As part of the implementation stage, the First Nations may choose to coordinate projects as a group, which could provide efficiencies and economies of scale. Community-specific considerations will be reflected in the implementation plans (e.g., KI-Wapekeka Tie Line).

<u>Remotes-Serviced Community – Repurposing DGS</u>

1. Funding application to ISC
2. ISC funding approval
3. Legal agreements
    a. Hire legal advisors
    b. New First Nation / Remotes / ISC Electrification Agreement
    c. Update or new Section 28(2) permit
4. Remotes completes transition upgrades to their DGS
    a. Remotes and the First Nation enter into a funding agreement for Remotes to complete the required upgrades to their diesel generating stations
    b. Remotes completes upgrades to their diesel generating stations

Through separate processes, Remotes to seek any necessary regulatory amendments/approvals required to recover costs related to fuel and O&M costs through the RRRP, and FN / ISC to address any ISC-funded critical asset backup power gaps. This does not include the replacement, upgrade or repair of existing generators already supporting critical ISC funded assets.

Page 628 of 798

IPA Community – Repurposing DGS

1. Funding application to ISC
2. ISC funding approval
3. ESA / TSSA assess DGS to identify deficiencies to industry standards / regulations (backup)
4. Environmental Site Assessment completed to determine baseline and identify Health & Safety required remediation work
5. Legal agreements
    a. Hire legal advisors
    b. Remotes / First Nation / ISC Operating Agreement (including environmental responsibility)
    c. Section 28(2) or Land Use Permit (if required)
6. Procure design consultant to design the upgrades based on ESA / TSSA assessments / Remotes requirements for backup power.
7. Design consultant to create Tender Packages and complete Tender Process.
8. Competitive tender awarded and repurposing of DGS completed

Through separate processes, Remotes to seek any necessary regulatory amendments/approvals and FN / ISC to address any ISC-funded critical asset backup power gaps. This does not include the replacement, upgrade or repair of existing generators already supporting critical ISC funded assets.

Exceptions: Pikangikum, North Caribou Lake, and Wawakapewin – Critical Asset Backup Only

1. Funding application to ISC
2. ISC funding approval
3. Competitive tender to supply and install required standby backup power generators at ISC-funded critical assets, based on identified gaps, including community gathering place (e.g., school) and fire hall. This does not include the replacement, upgrade or repair of existing generators already supporting critical ISC funded assets.

Page 629 of 798

12. Risks & Mitigation Strategies

Risk Category	Risk	Mitigation
Project Funding Delays	– Funding delays will impact the timeline to complete the necessary backup power investments by grid connection dates	– ISC securing adequate funding to support implementation of backup power plan – Opiikapawiin available to provide ongoing support to the Connecting Communities on funding applications and implementation – Open and continuous dialogue with ISC staff as well as key decision makers
Cost/Time Overruns	– Infrastructure projects in remote, northern Ontario often face cost and timeline risks – Costs provided by Remotes to date are estimates and could change – There could be more critical asset gaps than identified through ISC desktop analysis – Costs to address any industry standard or regulation deficiencies identified by Remotes at an existing IPA DGS	– Hold Remotes accountable to their estimates for Remotes-serviced communities – Ensure well defined scope of services during procurement – Cost controls in place under ISC's Capital Facilities and Maintenance Program (CFMP), including a dedicated budget for contingencies at design and construction stages – Regular and open communication among project partners – Allowance in the budgetary estimates for addressing any industry standard or regulation deficiencies at an existing IPA DGS – Following further assessment, if additional substantial costs emerge In IPA communities that no longer make community-wide backup power financially feasible; at a minimum, ISC will work with the community to facilitate backup power for ISC-funded critical community assets (Refer to Section 6.3)
Parties Unable to Reach an Operating Agreement	– ISC, First Nation and Remotes unable to reach an agreement related to environmental responsibility – Other issues raised by signatories cannot be agreed upon –	– Regular engagement with ISC and Remotes Environmental Teams – Regular engagement with leadership and First Nation representatives regarding alternative options – Regular engagement with leadership and First Nation representatives regarding any other issues raised
OEB Denies Remotes Costs for Backup Power	– Any backup power costs denied by the OEB would result in Remotes being unable to recover the cost, and would impact the company's willingness to operate backup power assets going forward –	– Remotes letter confirming commitment to backup power until 2030, at a minimum – Demonstrated backup power precedents under provincial energy regulation – Ministry of Energy, Northern Development & Mines participation and input into the Plan and BPWG – Open and continuous dialogue with provincial staff as well as key decision makers

		– ISC-funded critical assets will have dedicated standby generators
Overall Coordination of Implementation by the 16 Connecting Communities	– Opportunities for efficiencies and economies of scale may be missed – Lack of coordination and/or information sharing among communities may result in repeated mistakes	– Include realistic budget for implementation costs – Opiikapawiin available to provide support
First Nation Support/Capacity for Project	– Change in support from a Connecting Community or limited capacity to implement in a timely manner – Leadership and/or representative changes during the project	– Regular engagement with leadership and First Nation representatives (e.g. Tribal Council) by project partners – Opiikapawiin available to develop communications materials and provide support

13. Next Steps, Post-Implementation Monitoring, and Plan Beyond 2030

First Nation LP mandated Opiikapawiin to work with Canada, and project partners, to develop a Backup Power Plan for the 16 Connecting Communities. Through Article N of the Parallel Process Agreement, Canada committed to work with the project partners to develop and implement a backup power plan for the 16 connecting communities. This Plan, completed in April 2020, recommends repurposing the existing diesel generation stations in 13 of the 16 communities to provide community-wide backup power until the end of 2030. As it is not possible to repurpose the existing diesel generating stations in Pikangikum First Nation, North Caribou Lake First Nation, and Wawakapewin First Nation, the Plan recommends backup power be provided by dedicated standby generators for ISC-funded critical community assets.

Unfortunately, due to Covid-19 travel restrictions, only 4 of the 16 second round community engagement sessions could be completed. In order to advance backup power solutions in time with the grid connection schedule, the BPWG suggests shifting from planning to implementation of the recommended backup power solutions. Should there be any changes to the proposed Plan, those will be reflected through the implementation phase documents (e.g. funding support application, legal agreements).

Once grid connection has occurred and backup power solutions are in place, project partners will enter the monitoring phase. Wataynikaneyap and Remotes will respond to, and track, any outages that occur. Prior to 2030, ISC and Remotes have confirmed their willingness to work with the Connecting Communities to assess the need, costs, and benefit of ongoing backup power beyond 2030. Depending on community growth, Remotes has indicated that the diesel generating stations could provide full backup for years beyond 2030 without requiring any large capital investments. In addition, there may be options (e.g. load shedding) to extend the utility of the backup generators beyond 2030 with minimal capital investments.

Page 631 of 798

Page 632 of 798

Backup Power Plan Summary Sheet – Bearskin Lake First Nation

1. Summary

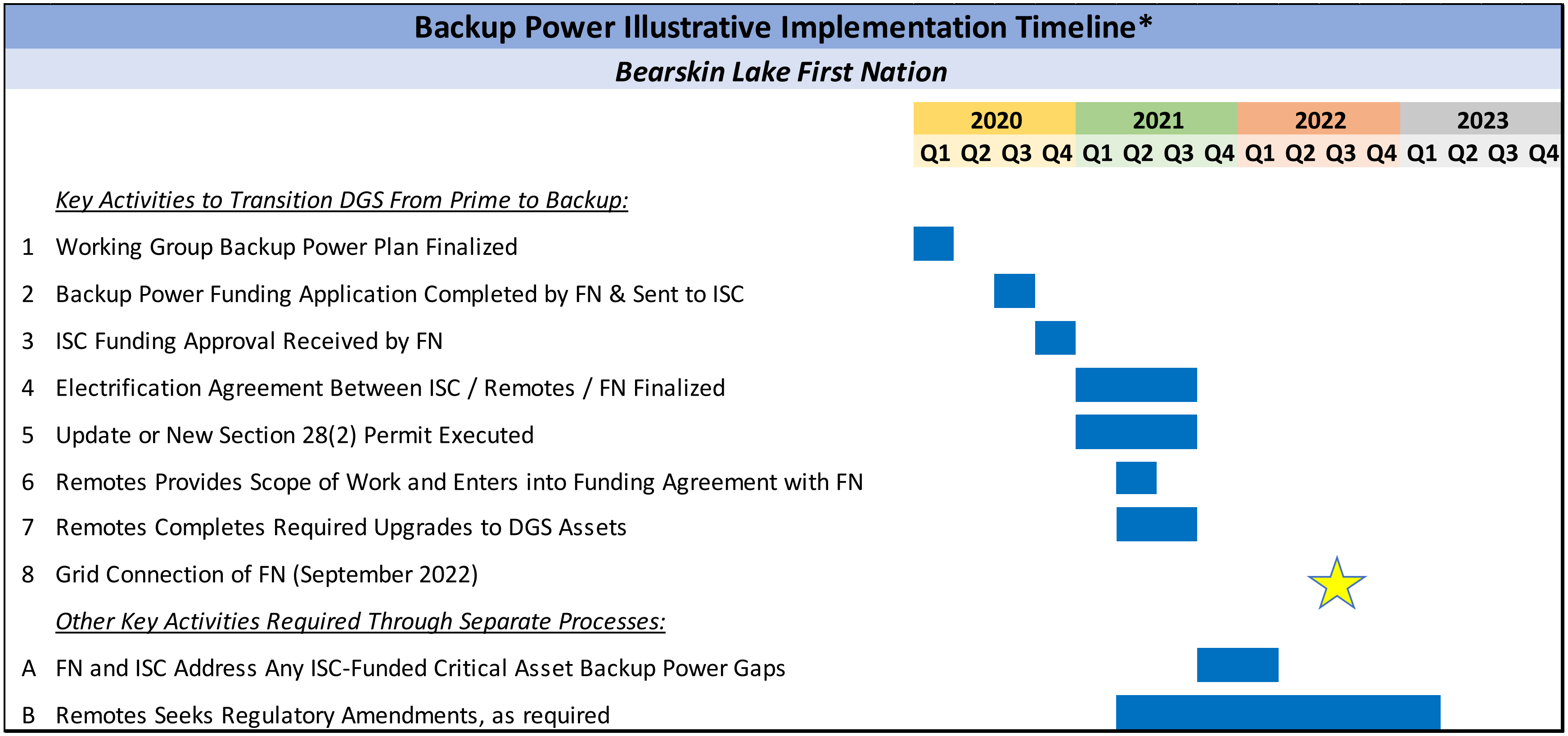
Estimated Connection Date:	September 2022
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Updated Electrification Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Updated Electrification Agreement with Remotes • DGS upgrades to operate as backup power

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$118,000	$20,000	$122,400	$1,767,108	**$2,027,508**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$100,000	$1,063,200	N/A	**$1,163,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 633 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 634 of 798

Backup Power Plan Summary Sheet – Deer Lake First Nation

1. Summary

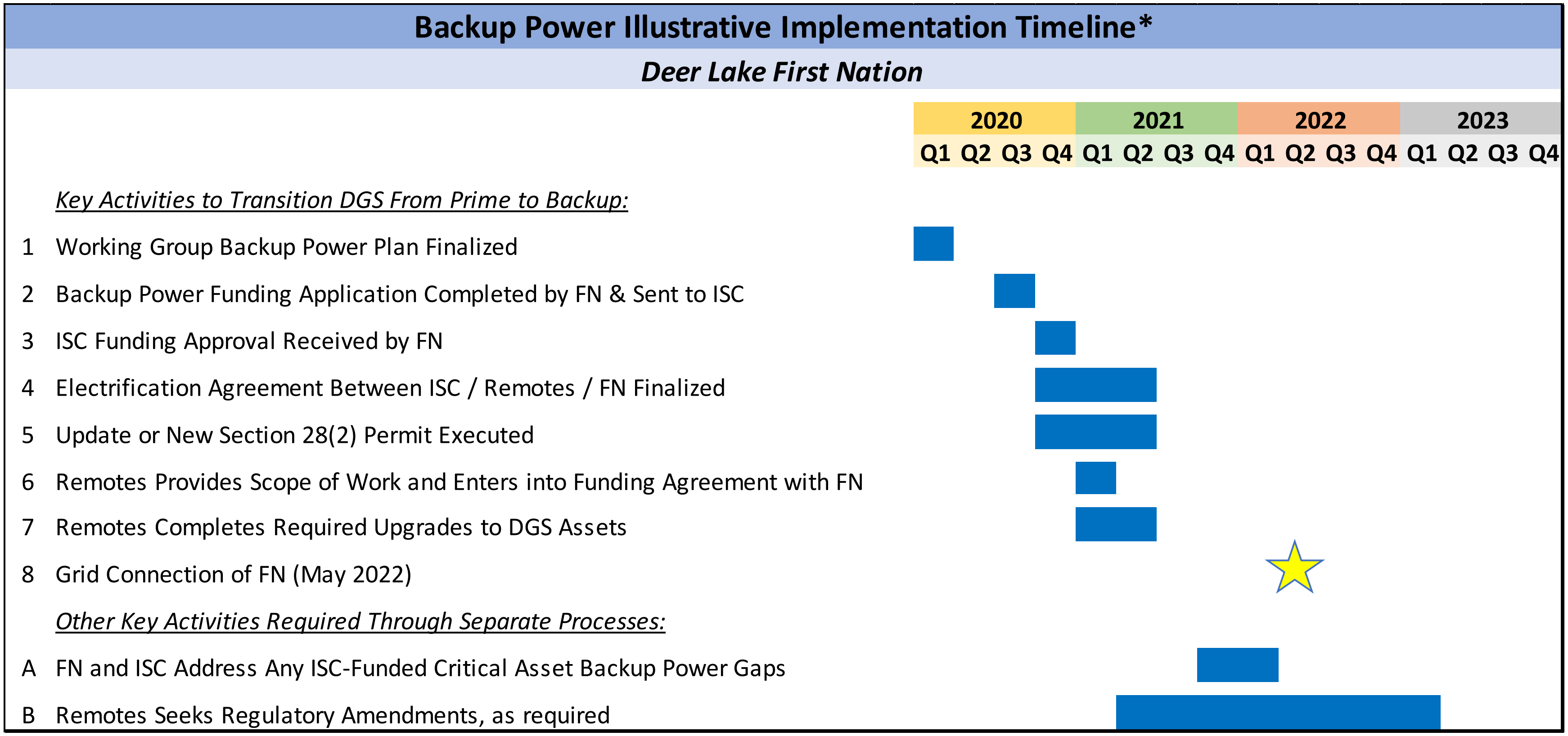
Estimated Connection Date:	May 2022
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Updated Electrification Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Updated Electrification Agreement with Remotes • DGS upgrades to operate as backup power

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$118,000	$20,000	$391,200	$2,321,055	**$2,850,255**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$100,000	$391,200	N/A	**$491,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 635 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 636 of 798

Backup Power Plan Summary Sheet – Kasabonika Lake First Nation

1. Summary

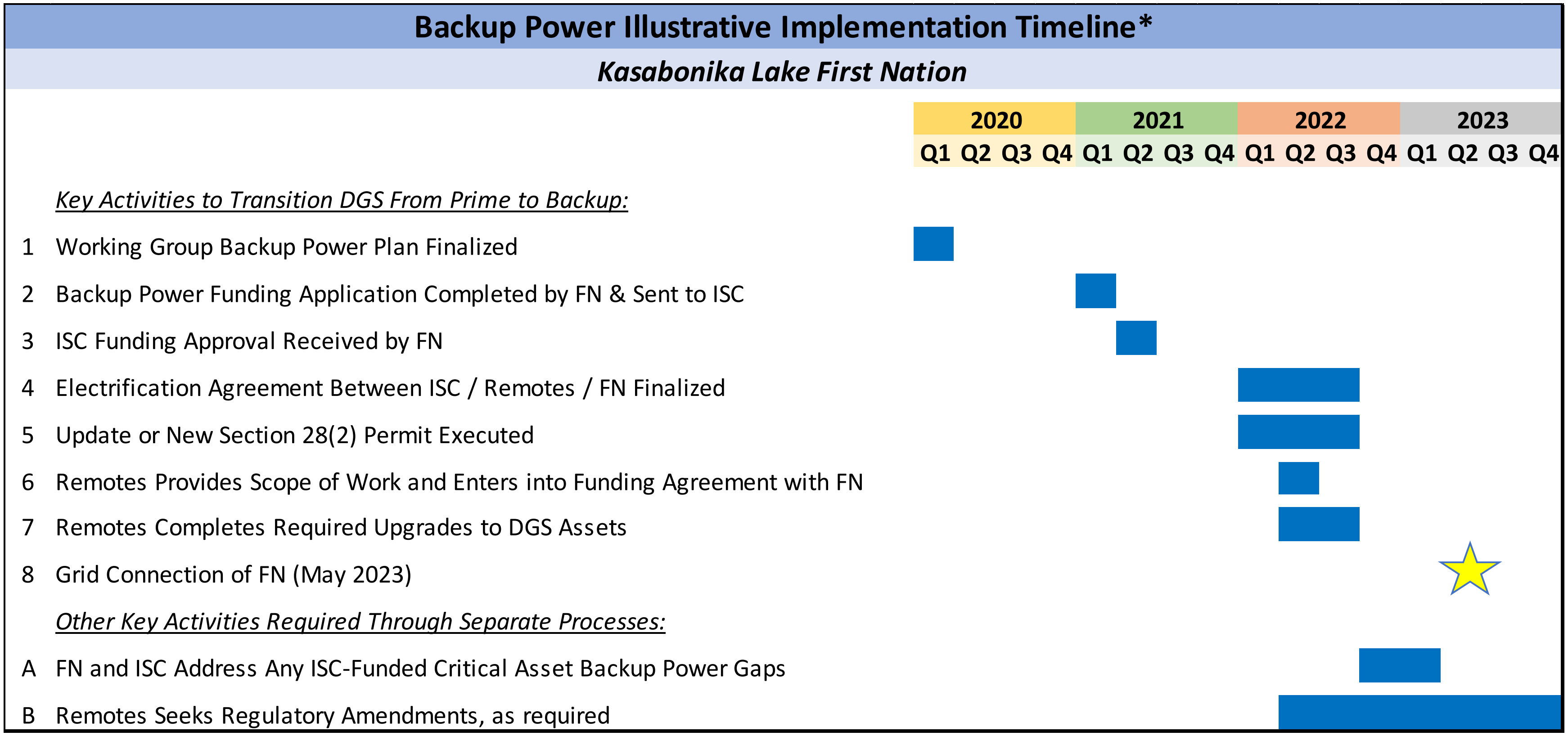
Estimated Connection Date:	May 2023
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Updated Electrification Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Updated Electrification Agreement with Remotes • DGS upgrades to operate as backup power

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$118,000	$20,000	$150,400	$1,888,203	**$2,176,603**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$100,000	$934,400	N/A	**$1,034,400**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 637 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 638 of 798

Backup Power Plan Summary Sheet – Kingfisher Lake First Nation

1. Summary

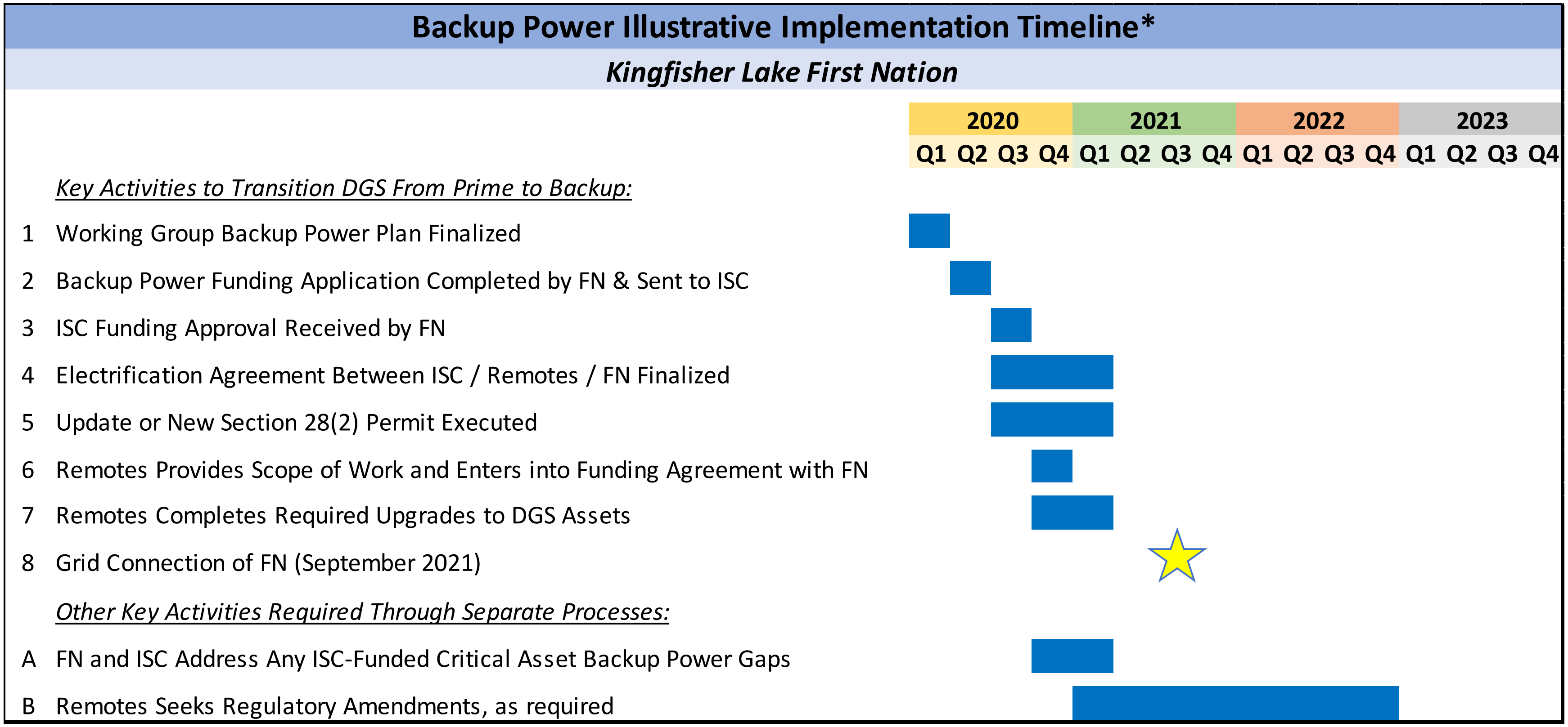
Estimated Connection Date:	September 2021
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Updated Electrification Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Operating Agreement with Remotes • Determine environmental baseline at DGS site • Complete upgrades required to operate as backup power

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$118,000	$20,000	$150,400	$2,202,541	**$2,490,941**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$100,000	$1,091,200	N/A	**$1,191,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 639 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 640 of 798

Backup Power Plan Summary Sheet – Kitchenuhmaykoosib Inninuwug First Nation

1. Summary

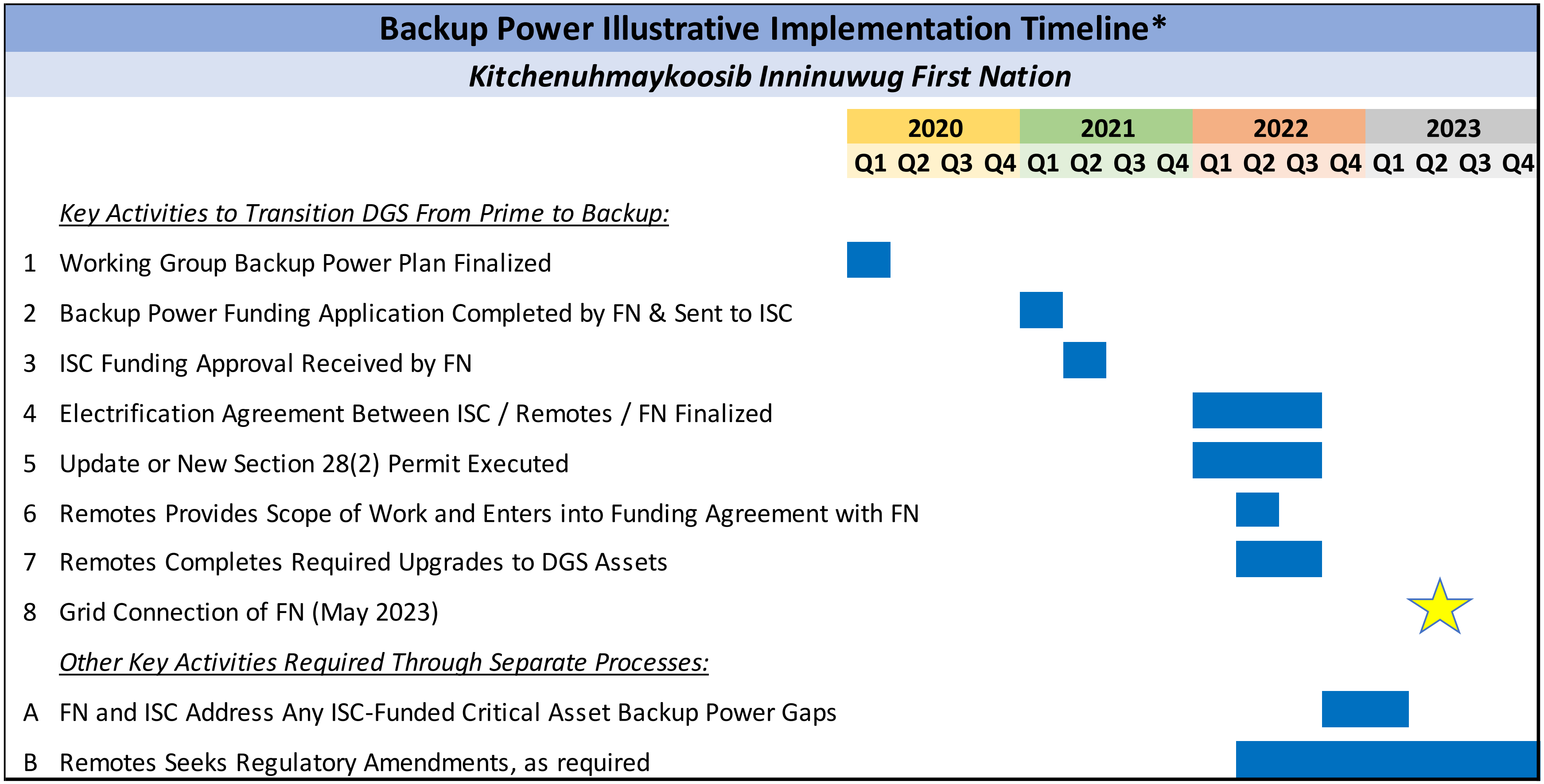
Estimated Connection Date:	May 2023
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Updated Electrification Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Updated Electrification Agreement with Remotes • DGS upgrades to operate as backup power

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$118,000	$20,000	$234,400	$2,375,161	**$2,747,561**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$100,000	$234,400	N/A	**$334,400**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 641 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 642 of 798

Backup Power Plan Summary Sheet – North Caribou Lake First Nation

1. Summary

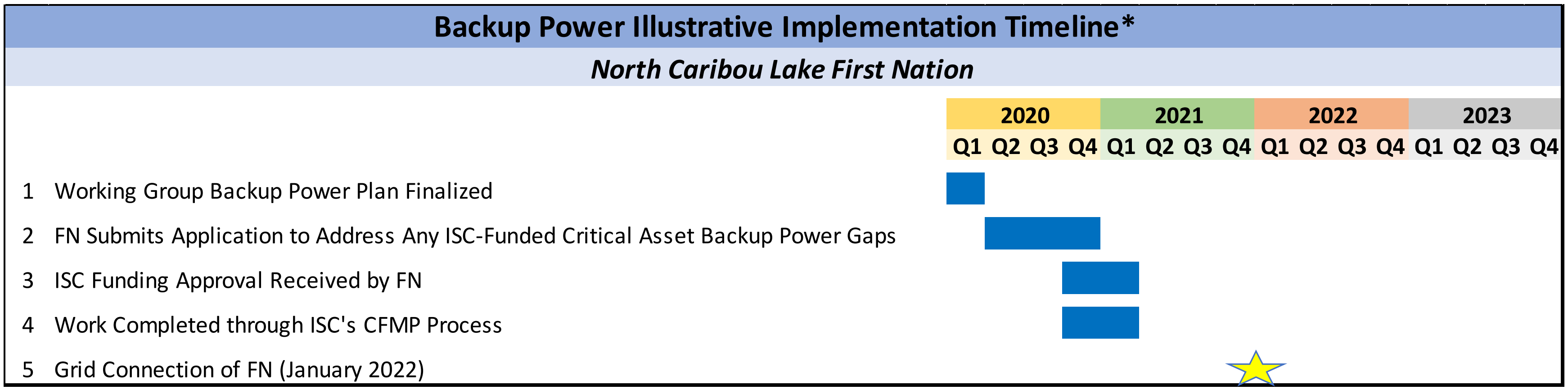
Estimated Connection Date:	January 2022
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Critical Asset Backup Power Only
Recommended Operator:	N/A
Recommended Funding Responsibility:	ISC to fund Health & Safety Critical Asset gaps
Implementation Requirements:	• Confirm funding commitments • If/when there are critical assets, ensure backup is in place

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
New containerized DGS on greenfield site	$3,903,900	$390,000	$206,400	$1,979,823	**$6,480,123**	• Will provide full community backup • Requires a new site • More implementation risks (lead times, winter road availability, permitting requirements, etc.) • Allows for decommissioning and clean-up of any contamination at the DGS site
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$100,000	$1,147,200	N/A	**$1,247,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 643 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 644 of 798

Backup Power Plan Summary Sheet – Pikangikum First Nation

3. Summary

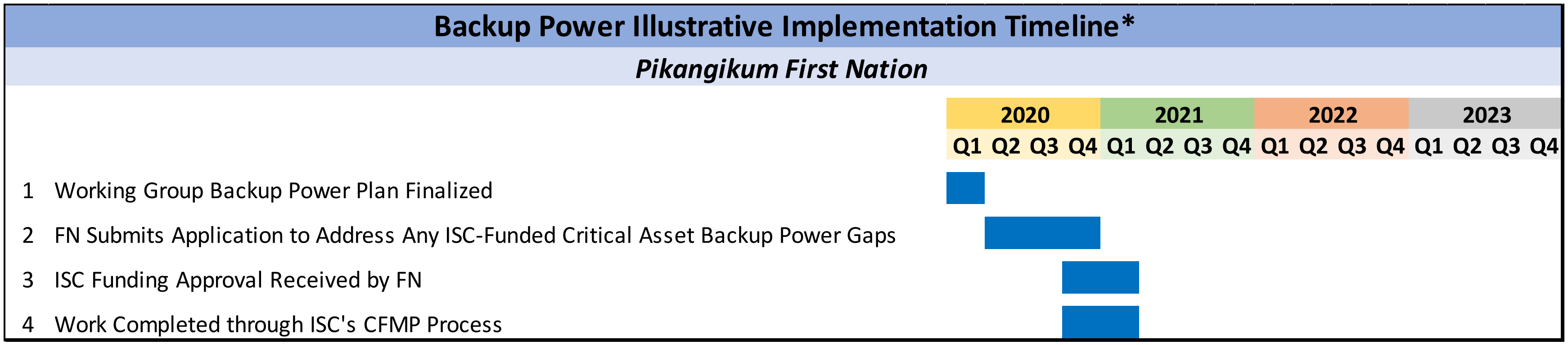
Estimated Connection Date:	Grid Connected in December 2018
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Critical Asset Backup Power Only
Recommended Funding Responsibility:	ISC to fund Health & Safety Critical Asset gaps
Implementation Requirements:	• Confirm funding commitments • Ensure critical asset backup is in place

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
New containerized DGS on greenfield site	$5,848,700	$390,000	$122,400	$2,037,863	**$8,398,963**	• Will provide full community backup • Requires a new site • More implementation risks (lead times, winter road availability, permitting requirements, etc.) • Allows for decommissioning and clean-up of any contamination at the DGS site
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$12,500	$122,400	N/A	**$134,900**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 645 of 798

2. Implementation Timeline*



*Timeline is estimated and is subject to change

Page 646 of 798

Backup Power Plan Summary Sheet – Sachigo Lake First Nation

1. Summary

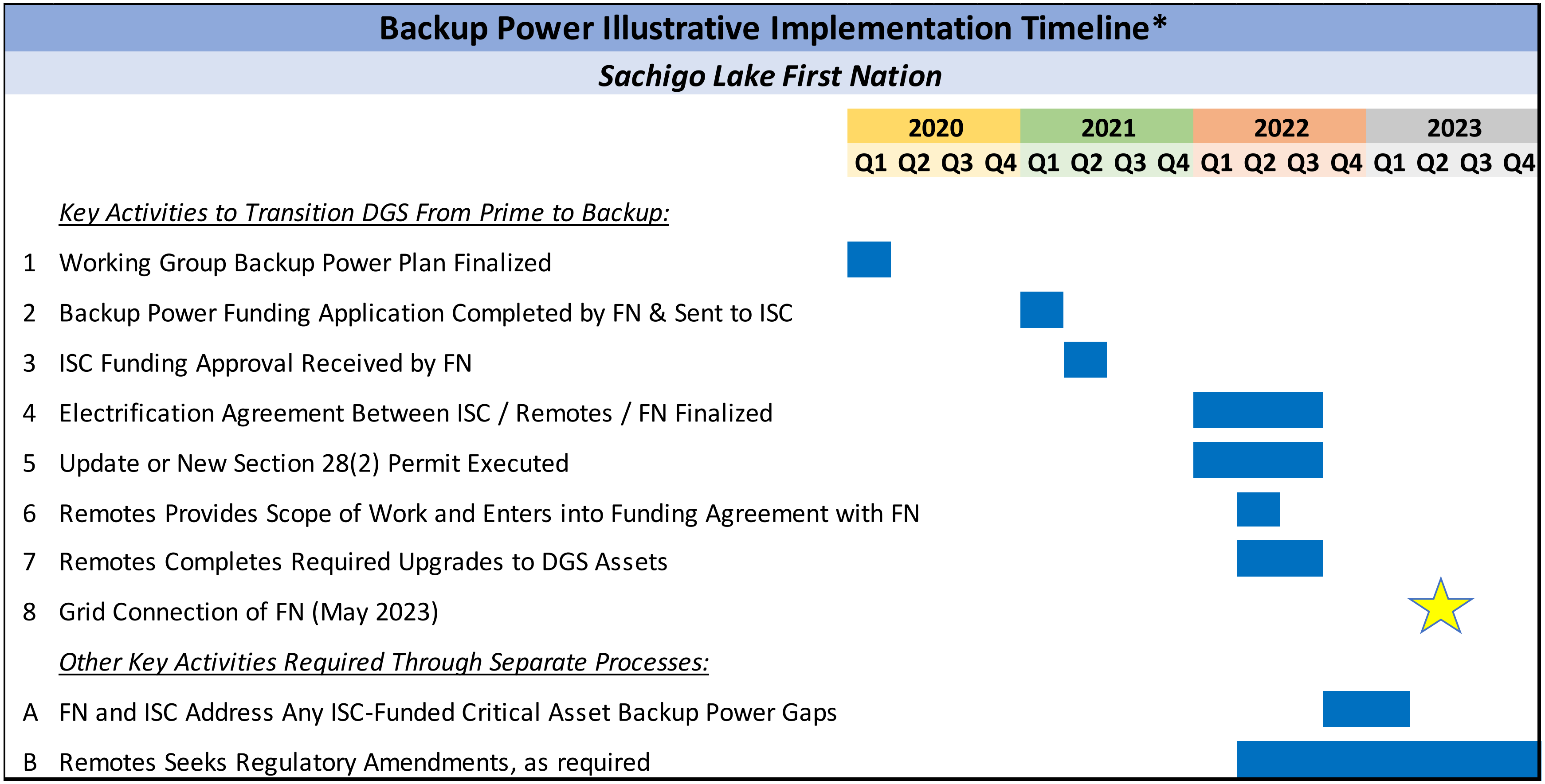
Estimated Connection Date:	May 2023
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Updated Electrification Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Updated Electrification Agreement with Remotes • DGS upgrades to operate as backup power

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$118,000	$20,000	$178,400	$1,781,469	**$2,097,869**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$100,000	$1,119,200	N/A	**$1,219,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 647 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 648 of 798

Backup Power Plan Summary Sheet – Sandy Lake First Nation

1. Summary

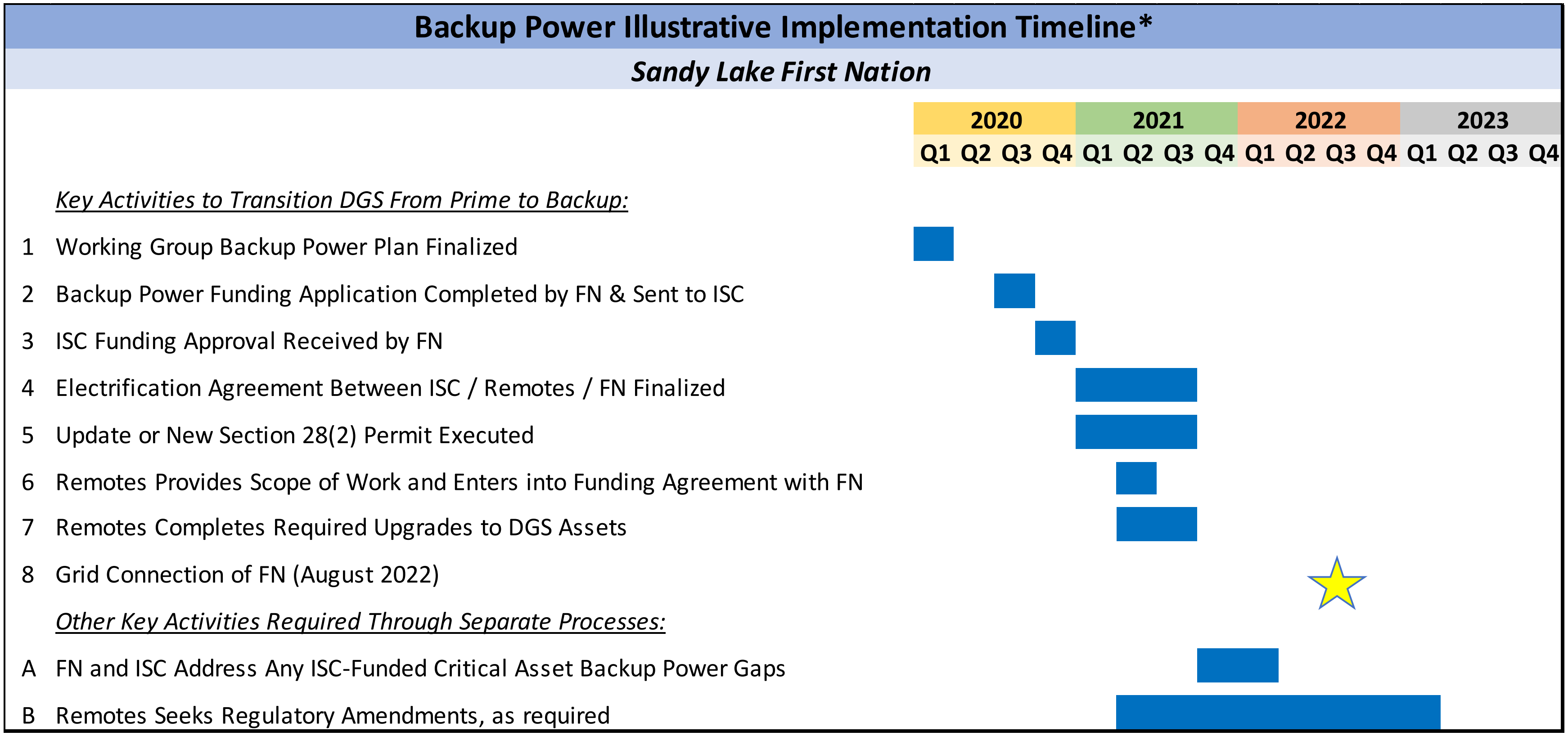
Estimated Connection Date:	August 2022
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Updated Electrification Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Updated Electrification Agreement with Remotes • DGS upgrades to operate as backup power

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$118,000	$20,000	$150,400	$2,412,953	**$2,701,353**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$100,000	$307,200	N/A	**$407,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 649 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 650 of 798

Backup Power Plan Summary Sheet – Wapekeka First Nation

1. Summary

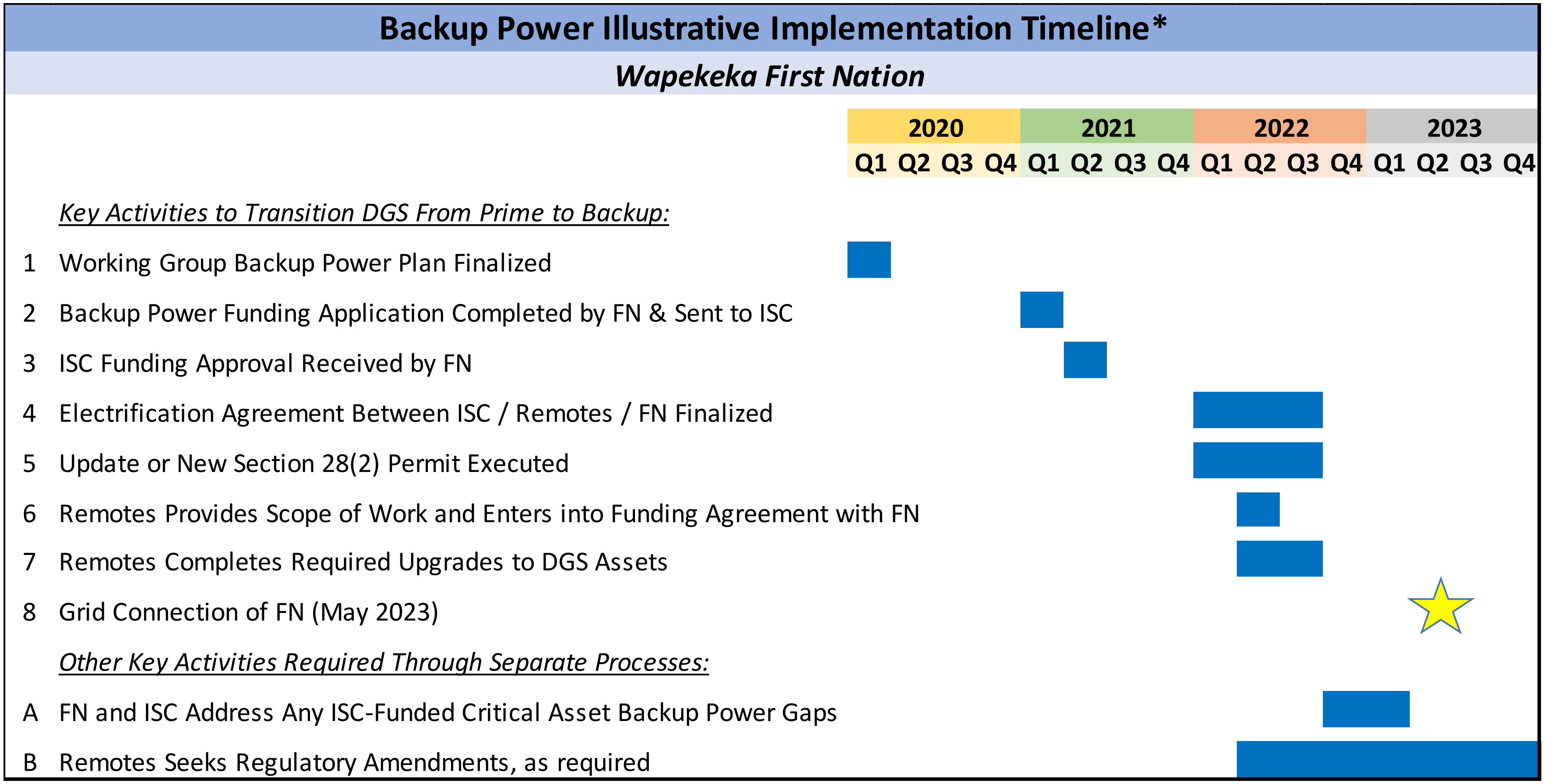
Estimated Connection Date:	May 2023
Current Local Distribution Company:	Hydro One Remote Communities Inc.
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Updated Electrification Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Updated Electrification Agreement with Remotes • DGS upgrades to operate as backup power

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$118,000	$20,000	$150,400	$1,741,026	**$2,029,426**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$100,000	$934,400	N/A	**$1,034,400**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 651 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 652 of 798

Backup Power Plan Summary Sheet – Keewaywin First Nation

1. Summary

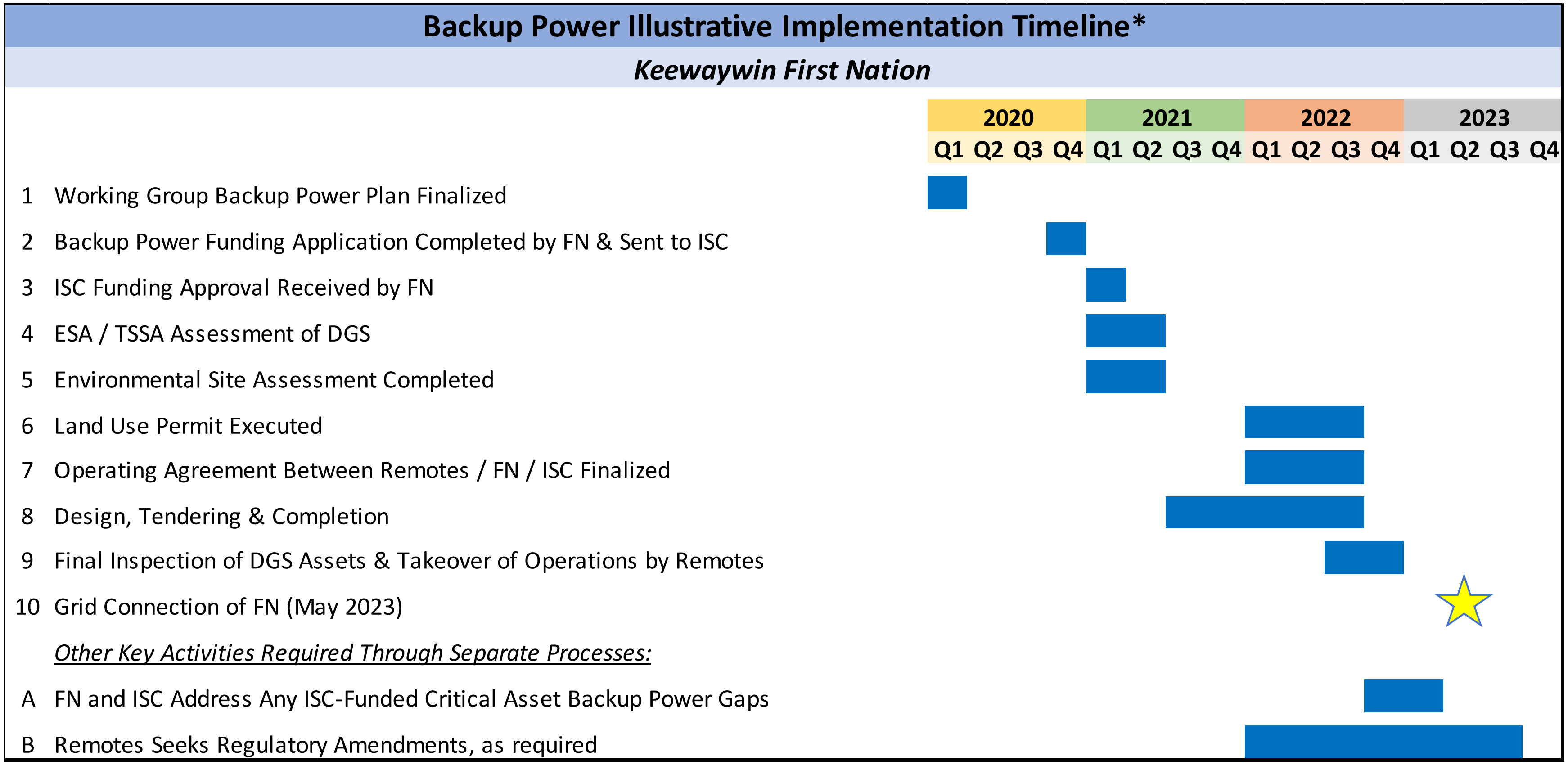
Estimated Connection Date:	May 2023
Current Local Distribution Company:	Independent Power Authority
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Operating Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Operating Agreement with Remotes • Determine environmental baseline at DGS site • Complete upgrades required to operate as backup power

Options	Estimated Initial / Transitional Costs	IPA Compliance / Industry Standard	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$684,000	$300,000	$680,000	$122,400	$1,676,424	**$3,462,824**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
New containerized DGS on greenfield site	$3,568,400	N/A	$390,000	$122,400	$1,677,424	**$5,758,224**	• Will provide full community backup • Requires a new site • More implementation risks (lead times, winter road availability, permitting requirements, etc.) • Allows for decommissioning and clean-up of any contamination at the DGS site
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	N/A	$100,000	$1,063,200	N/A	**$1,163,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 653 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 654 of 798

Backup Power Plan Summary Sheet – Muskrat Dam First Nation

1. Summary

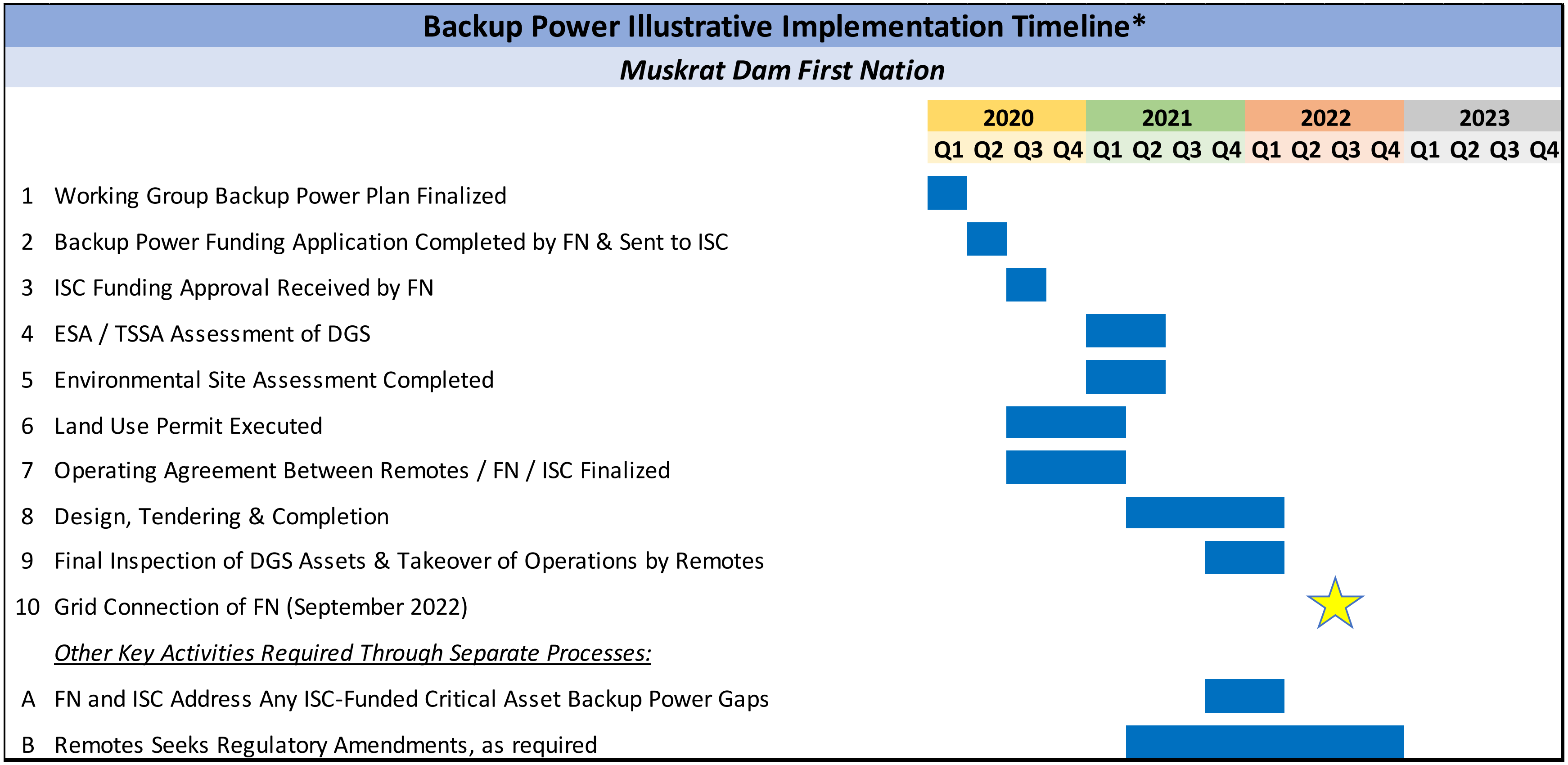
Estimated Connection Date:	September 2022
Current Local Distribution Company:	Independent Power Authority
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Operating Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Operating Agreement with Remotes • Determine environmental baseline at DGS site • Complete upgrades required to operate as backup power

Options	Estimated Initial / Transitional Costs	IPA Compliance / Industry Standard	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$199,000	$300,000	$680,000	$178,400	$1,703,496	**$3,060,896**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
New containerized DGS on greenfield site	$3,568,400	N/A	$390,000	$178,400	$1,704,496	**$5,841,296**	• Will provide full community backup • Requires a new site • More implementation risks (lead times, winter road availability, permitting requirements, etc.) • Allows for decommissioning and clean-up of any contamination at the DGS site
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	N/A	$100,000	$1,119,200	N/A	**$1,219,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 655 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 656 of 798

Backup Power Plan Summary Sheet – North Spirit Lake First Nation

1. Summary

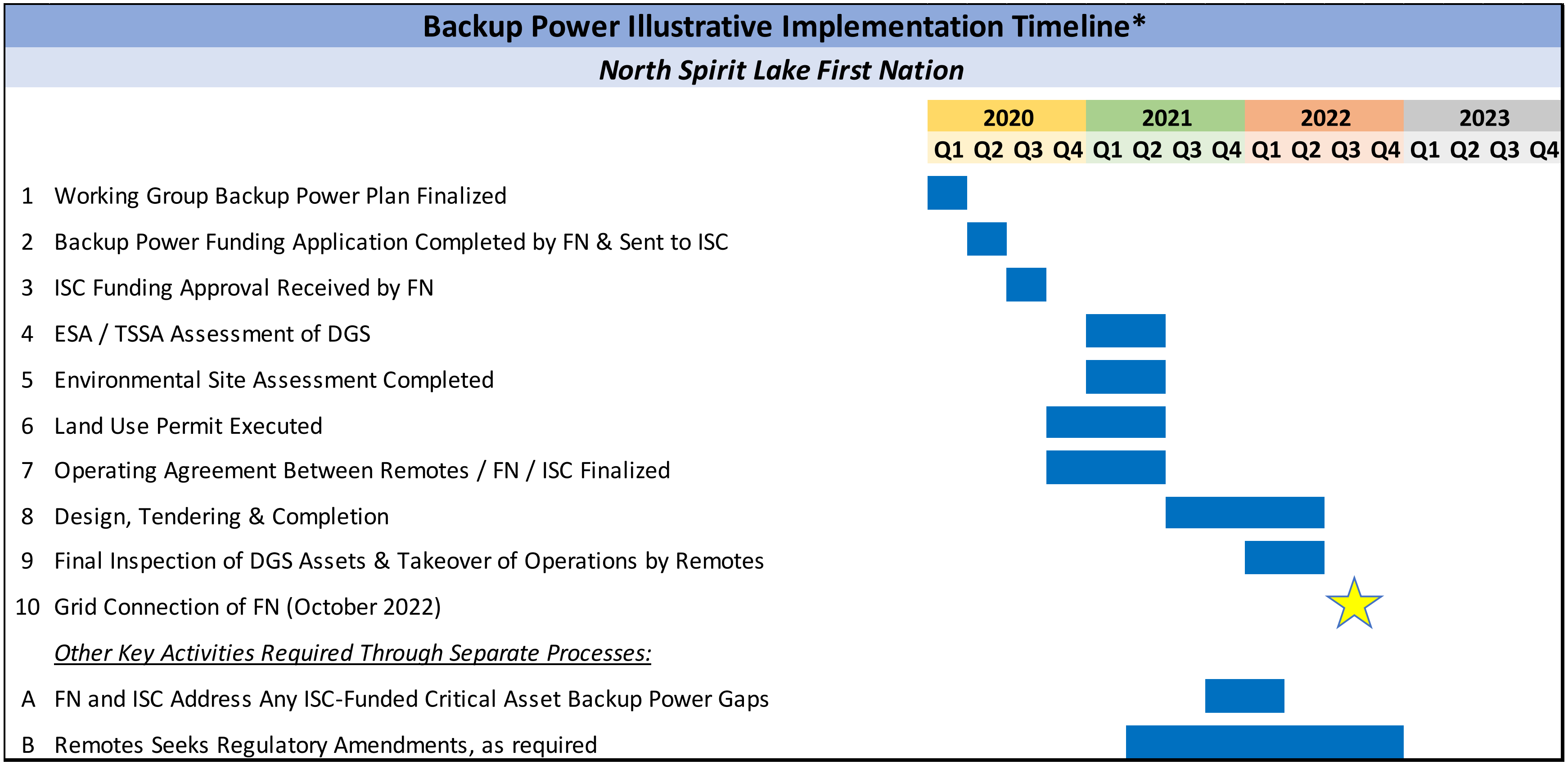
Estimated Connection Date:	October 2022
Current Local Distribution Company:	Independent Power Authority
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Operating Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Operating Agreement with Remotes • Determine environmental baseline at DGS site • Complete upgrades required to operate as backup power

Options	Estimated Initial / Transitional Costs	IPA Compliance / Industry Standard	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$209,000	$300,000	$680,000	$335,200	$1,648,790	**$3,172,990**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
New containerized DGS on greenfield site	$3,568,400	N/A	$390,000	$335,200	$1,649,790	**$5,943,390**	• Will provide full community backup • Requires a new site • More implementation risks (lead times, winter road availability, permitting requirements, etc.) • Allows for decommissioning and clean-up of any contamination at the DGS site
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	N/A	$100,000	$1,119,200	N/A	**$1,219,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 657 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 658 of 798

Backup Power Plan Summary Sheet – Poplar Hill First Nation

1. Summary

Estimated Connection Date:	April 2022
Current Local Distribution Company:	Independent Power Authority
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Operating Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Operating Agreement with Remotes • Determine environmental baseline at DGS site • Complete upgrades required to operate as backup power

Options	Estimated Initial / Transitional Costs	IPA Compliance / Industry Standard	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$199,000	$300,000	$680,000	$279,200	$1,860,872	**$3,319,072**	• Will provide full community backup • Does not allow for near term clean-up of contaminated DGS site • Requires Operating Agreement with Remotes
New containerized DGS on greenfield site	$3,568,400	N/A	$390,000	$279,200	$1,860,872	**$6,098,472**	• Will provide full community backup • Requires a new site • More implementation risks (lead times, winter road availability, permitting requirements, etc.) • Allows for decommissioning and clean-up of any contamination at the DGS site
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	N/A	$100,000	$1,063,200	N/A	**$1,163,200**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

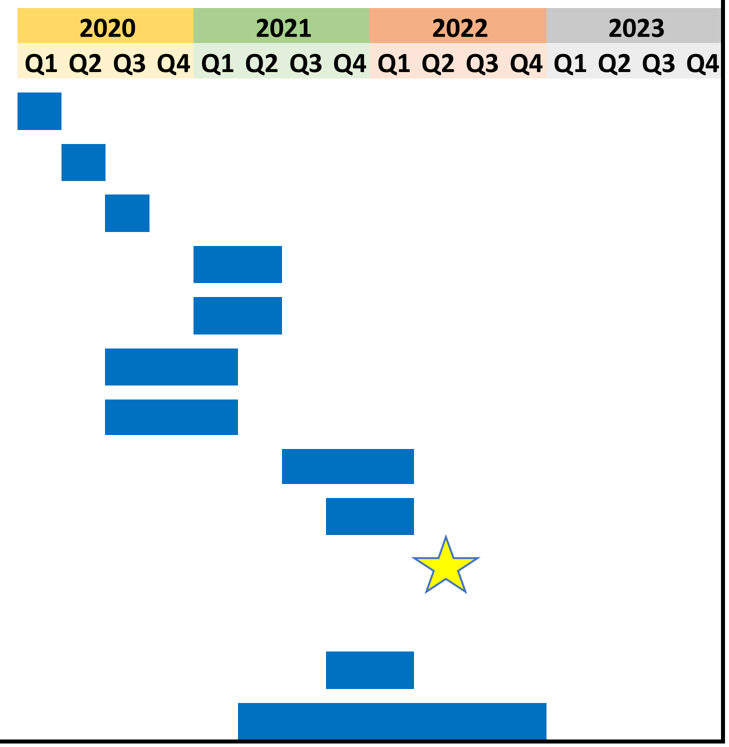
1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 659 of 798

2. Implementation Timeline

Backup Power Illustrative Implementation Timeline*

Poplar Hill First Nation



1 Working Group Backup Power Plan Finalized
2 Backup Power Funding Application Completed by FN & Sent to ISC
3 ISC Funding Approval Received by FN
4 ESA / TSSA Assessment of DGS
5 Environmental Site Assessment Completed
6 Land Use Permit Executed
7 Operating Agreement Between Remotes / FN / ISC Finalized
8 Design, Tendering & Completion
9 Final Inspection of DGS Assets & Takeover of Operations by Remotes
10 Grid Connection of FN (April 2022)

Other Key Activities Required Through Separate Processes:

A FN and ISC Address Any ISC-Funded Critical Asset Backup Power Gaps
B Remotes Seeks Regulatory Amendments, as required

*Timeline is estimated and is subject to change

Page 660 of 798

Backup Power Plan Summary Sheet – Wawakapewin First Nation

3. Summary

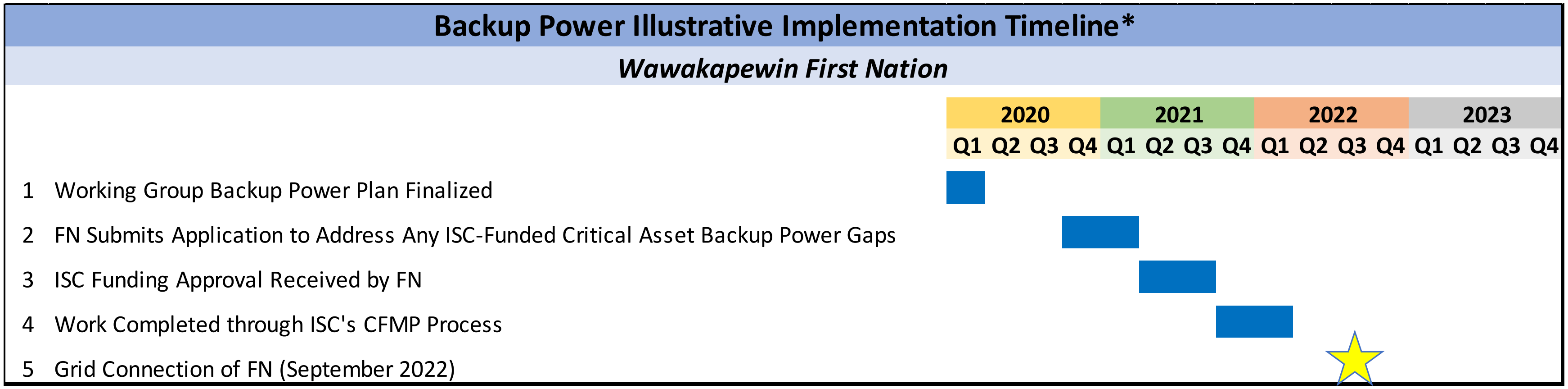
Estimated Connection Date:	September 2022
Current Local Distribution Company:	Independent Power Authority
Recommended Option (*See Below*):	Critical Asset Backup Power Only
Recommended Operator:	N/A
Recommended Funding Responsibility:	ISC to fund Health & Safety Critical Asset gaps
Implementation Requirements:	• Confirm funding commitments • If/when there are critical assets, ensure backup is in place

Options	Estimated Initial / Transitional Costs	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
New containerized DGS on greenfield site	$2,901,800	$390,000	$0	$1,559,149	**$4,850,949**	• Will provide full community backup • Requires a new site • More implementation risks (lead times, winter road availability, permitting requirements, etc.) • Allows for decommissioning and clean-up of any contamination at the DGS site • Requires that community access issues are addressed
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	$0	$0	N/A	**$0**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 661 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 662 of 798

Backup Power Plan Summary Sheet – Wunnumin Lake First Nation

1. Summary

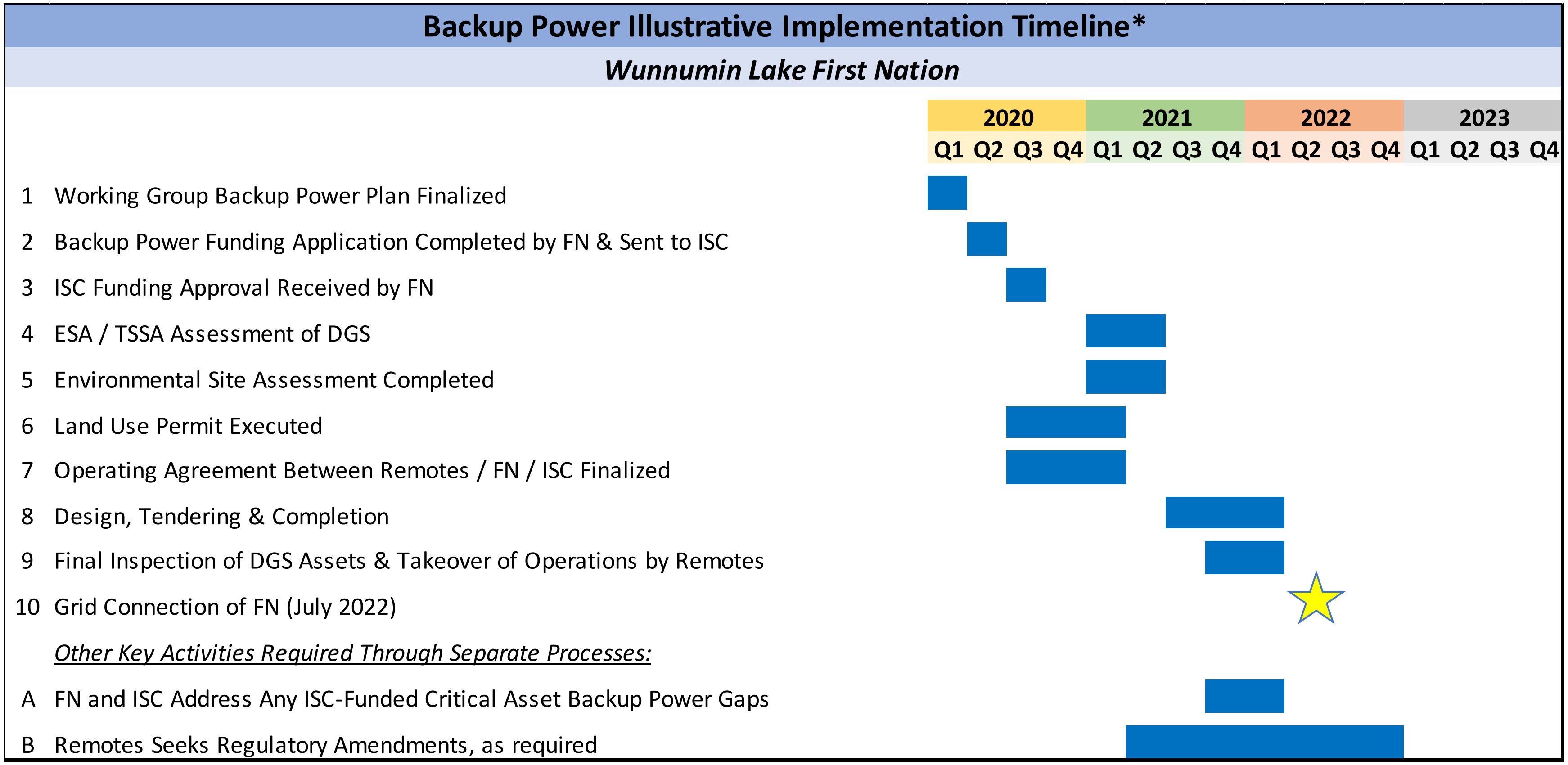
Estimated Connection Date:	July 2022
Current Local Distribution Company:	Independent Power Authority
Recommended Option (*See details below*):	Re-purpose existing DGS for Backup
Recommended Operator:	Operating Agreement with Remotes until 2030, at a minimum
Recommended Funding Responsibility:	Transitional Capital Costs: ISC O&M and Replacement Capital Costs: Remotes
Implementation Requirements:	• Confirm funding commitments • Operating Agreement with Remotes • Determine environmental baseline at DGS site • Complete upgrades required to operate as backup power

Options	Estimated Initial / Transitional Costs	IPA Compliance / Industry Standards	Estimated Implementation Costs	ISC Funded Health and Safety Critical Assets Gaps	Estimated O&M Costs to 2030	Total Estimated Costs to 2030	Considerations
Re-Purpose Existing DGS for Backup	$209,000	$300,000	$680,000	$150,400	$2,006,226	**$3,345,626**	• Will provide full community backup • Does not allow for near-term clean-up of contamination at the DGS site • Requires Operating Agreement with Remotes
New containerized DGS on greenfield site	$4,299,900	$0	$390,000	$150,400	$2,006,226	**$6,846,526**	• Will provide full community backup • Requires a new site • More implementation risks (lead times, winter road availability, permitting requirements, etc.) • Allows for decommissioning and clean-up of any contamination at the DGS site
ISC to ensure ISC-funded critical assets[1] have backup power	N/A	N/A	$100,000	$934,400	N/A	**$1,034,400**	• Does not provide full community backup • Allows for decommissioning and clean-up of any contamination at the DGS site

1 - Critical Assets are: water treatment plants, wastewater treatment plants & related lift stations, schools, nursing stations & nurse residences, and fire halls

Page 663 of 798

2. Implementation Timeline



*Timeline is estimated and is subject to change

Page 664 of 798

Appendix B – BBA Backup Power Report

Document to be circulated as separated PDF file.

Page 665 of 798

Appendix C – Hydro One Remote Communities Inc. Backup Power Report (Dec 2018)

Document to be circulated as separated PDF file.

Appendix D – Hydro One Remotes Containerized DGS Option Annex (Nov 2019)

Document to be circulated as separated PDF file.

Page 667 of 798

First Nation LP Shareholders Meeting

MOTION #07: **Moved by** **Chief Eno H. Anderson**
Seconded by **Chief Jacob Strang**

WHEREAS 22 First Nations are the shareholders of 2472881 Ontario Limited (the "Corporation"), and 2472881 Ontario Limited is the General Partner of First Nation LP ("FNLP");

AND WHEREAS the Indigenous people will continue to exercise s. 35 Aboriginal and Treaty rights according to our understanding of the spirit and intent of the Treaty as passed down to us by our elders, and also to exercise our inherent rights given to us by the Creator, across all of our homelands;

AND WHEREAS FNLP has contracted with Opiikapawiin Services LP ("OSLP") to provide various services relating to the Wataynikaneyap Transmission Project;

AND WHEREAS due to the length and remoteness of the Wataynikaneyap Transmission Project, there are risks of power outages, which negatively impact the wellbeing of First Nations communities;

AND WHEREAS the May 2018 BBA Report estimated the reliability of the Wataynikaneyap transmission lines, evaluated backup options, and recommended utilization of existing generators as the best potential near-term backup power solution;

AND WHEREAS the December 2018 Hydro One Remotes Report recommends that existing community diesel generation assets be repurposed to provide centralized backup power in each community until 2030, as a minimum;

AND WHEREAS the Parallel Process Agreement includes a commitment by Canada to additional planning on backup power, to be completed in 2019.

THEREFORE, BE IT RESOLVED THAT Opiikapawiin Services LP will participate in the planning process identified in the Parallel Process Agreement, with the position that community wide backup power will be required in each of the First Nations to be connected by Wataynikaneyap Power, until 2030 as a minimum. The Backup Power Plan and commitments will need to address environmental responsibility and concerns, on a community by community basis, including all past and present grievances relating to historical environmental contaminations at the generator sites.

FINALLY, BE IT RESOLVED THAT ISC shall be responsible for all costs associated with all environmental remediation and clean up.
– CARRIED

Page 668 of 798

Appendix F – Letters from Indigenous Services Canada to the Connecting Communities (December 2018 / November 2019):

Document to be circulated as separated PDF file.

Page 669 of 798

Appendix G – Backup Power Working Group – Terms of Reference

May 7, 2019

Terms of Reference

Northern Ontario Grid Connection Project - Backup Power Working Group

The Northern Ontario Grid Connection Project, Backup Power Working Group (the "BPWG") will complete the required work to satisfy Article N (Backup Power) outlined in the Parallel Process Agreement, between Canada, Ontario, Wataynikaneyap Power LP, and First Nation LP. The Parallel Process Agreement states:

"The Parties acknowledge that the following two reports have been prepared in relation to back-up power and the Connecting Communities: the BBA report entitled "Remote Communities Backup Power Analysis" dated May 30, 2018 (the "BBA Report") and the draft Hydro One Remote Communities Inc. report entitled "Feasibility of Using Existing Diesel Generation Stations for Backup Power in Remote Grid-Connected Communities" (the "Remotes Report").

Canada and FNLP agree that they will continue to work together (and with the Connecting Communities) and will involve other interested parties as appropriate (including Ontario, Watay, the Independent Electricity System Operator and Hydro One Remotes Communities Inc.) to develop a backup power plan and commitments for the Connecting Communities that can be put into service following the Completion Date, including giving consideration to appropriate reliability and service standards, and, which may include the utilization of existing generation facilities that are in a condition to be safely operated for such purposes in accordance with good utility practice."

Objective

The BPWG will define and implement a process to develop a backup power implementation plan and commitments during calendar year 2019.

Participation

As stated in the Parallel Process Agreement, Canada and FNLP will work together, and as such will be the parties responsible for fulfilling the requirements under this ToR. Representatives from both Indigenous Services Canada (ISC) and First Nation LP (FNLP) will participate.

In addition, the following parties may be invited to participate in working group activities:

- Hydro One Remote Communities Inc. (Remotes)
- Ontario Ministry of Energy, Northern Development and Mines (MENDM)
- Wataynikaneyap Power (WP)
- Independent Electricity System Operator (IESO)
- Others, as determined by the BPWG

GCDOCS#44694944

Page 670 of 798

Activities

- Develop project workplan.
- Identify most feasible option for each community based on the Remotes Report, in collaboration with Remotes to confirm their ability to take over operation of each DGS for backup purposes.
- Identify requirements (costs, risks, assumptions, environmental issues, timelines, ownership/operation Transfer Agreements, etc.) for the proposed option.
- Engage with stakeholders (Remotes, MENDM, OEB, IESO, WP) to secure required commitments (ownership/operation, funding, etc.).
- Engage with each connecting community's Chief and Council and Tribal Council.
- Finalize option for each connecting community.
- Secure support letters from each connecting community.
- Reporting (on-going; assist WP in meeting OEB's semi-annual requirements).
- Draft and finalize Backup Power Implementation Plan (on-going).
- Assess status of community Emergency Preparedness Plans in terms of response to power outages.

Deliverables

- Meeting notes
- Monthly status report (to also be shared with WP)
- Interim Report (July 31, 2019)
- Draft Backup Power Implementation Plan (September 30, 2019)
- Final Backup Power Implementation Plan (November 30, 2019)

Meetings

Meeting will be bi-weekly, with at least one meeting per month in person. A representative from FNLP will chair the meetings. There will be a FNLP designated note taker for each meeting.

Amendments

This Terms of Reference may be amended if agreed to by the FNLP and ISC.

Jody Knibbs, A/Director Major Projects Implementation Office Indigenous Services Canada	Lucie Edwards, CEO First Nation LP

Page 671 of 798

Appendix H – Summary of BPWG Engagement with Connecting Communities

The following table summarizes the BPWG's engagement with the Connecting Communities as of April 30, 2020. The first round of engagement was led by Opiikapawiin, with the second round coordinated with Opiikapawiin and respective Tribal Councils.

Note, due to scheduling challenges and community closures related to Covid-19 precautions, not all community engagement sessions were held in each of the Connecting Communities.

	Connecting Community	Date(s) of Engagement	Round of Engagement	Outcomes
1.	Bearskin Lake	Sept. 24, 2019	1	• Support for centralized backup power • Concern with extended outages in the community as homes require power for heating & medical purposes • Support using existing DGS assets for backup power
		TBD	2	
2.	North Caribou Lake	Jul. 10, 2019	1	• Community does not want to evacuate due to outages • Concern with extended outages in the community as homes require power for heating & medical purposes • Support for centralized backup power • Concern with need for backup power beyond 2030
		Feb. 20, 2020	1	• Met with trappers and elders, was not a full community meeting.
3.	Sachigo Lake	Sept. 16, 2019	1	• Support using existing DGS assets for backup power • Support for centralized backup power
		TBD	2	
4.	Kasabonika Lake	Jul. 10, 2019	1	• Concern with lack of community representation on BPWG • Requested additional backup power information for review
		TBD	2	
5.	Kingfisher Lake	Jun. 19, 2019	1	• Backup power must meet needs of elders • Concern with extended outages in the community as homes require power for heating & medical purposes • Prefer supporting backup power via BCR over letter • Support using existing DGS assets for backup power • Support for centralized backup power
		TBD	2	
6.	Wapekeka	Nov. 19, 2019	1	• Support using existing DGS assets for backup power
		TBD	2	
7.	Kitchenuhmaykoosib Inninuwug (KI)	Mar. 10, 2020	1	• Support using existing DGS assets for backup power
		TBD	2	
8.	Pikangikum	Aug. 12, 2019	1	• Support for centralized backup power • Questions regarding backup power options • Concern with extended outages in the community as homes require power for heating & medical purposes
		TBD	2	
9.	Deer Lake	Jul. 18, 2019	1	• Support for centralized backup power • Prefers that DGS assets remain in the community

Page 672 of 798

				• Support using existing DGS assets for backup power
		TBD	2	
10.	Sandy Lake	TBD	1	
		TBD	2	
11.	Wawakapewin	Feb. 13, 2020	1	• Support for centralized backup power
		Mar. 12, 2020	2	• Support for centralized backup power
12.	Wunnumin Lake	Aug. 22, 2019	1	• Support using existing DGS assets for backup power • Support for centralized backup power • Would like environmental issues addressed • Opposed to transferring existing DGS assets to Remotes for free
		TBD	2	
13.	Muskrat Dam	Aug. 1, 2019	1	• Interested if community would receive payment from Remotes for backup power since assets are on MDFN land • Support for centralized backup power pending further community discussions
		TBD	2	
14.	Keewaywin	Aug. 27, 2019	1	• Chief wants new containerized DGS and Remotes compound to be located across the river to support a bridge project • Community opposed to transferring existing DGS assets to Remotes for free • Support for centralized backup power • Concern around Energy participating in BPWG due to perception that they have ulterior motives (i.e. mining)
		Mar. 3, 2020	2	• Concern for 'Critical Asset Only' option due to health & safety considerations • Community meeting held and support using existing DGS assets for backup power
15.	North Spirit Lake	Sept. 10, 2019	1	• Support for centralized backup power • Tentative support using existing DGS assets for backup power, but further discussions required with Tribal Council
		Feb. 27, 2020	2	• Community meeting held and support using existing DGS assets for backup power
16.	Poplar Hill	Jul. 19, 2019	1	• Support for centralized backup power • Concern with backup power beyond 2030 • Concern whether critical asset backup will still be in place if other backup power options are implemented • Support using existing DGS assets for backup power • Extent of DGS site contamination is unknown
		Feb. 13, 2020	2	• Strong support for re-purposing existing DGS assets for centralized backup power • Concern for 'Critical Asset Only' option due to health & safety and to protect homes (i.e. frozen pipes) • Backup Power Plan must consider all residents including sick and vulnerable

Note: the table above does not reflect group engagement sessions.

Page 673 of 798

Appendix I – Hydro One Remote Communities Inc. Letter

Hydro One
Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9
Toll Free: 1-888-825-8707
Telephone: (807) 474-2800
Fax: (807) 475-8123

hydro one
Partners in Powerful Communities

May 8, 2020

Lucie Edwards
Opiikapawiin Services Limited Partnership (OSLP)
l.edwards@oslp.ca

Re: Backup Power after Wataynikaneyap Grid Connection

On December 18, 2018, the First Nation Limited Partnerhsip (FNLP) Chiefs passed a resolution stating community wide backup power will be required in each of the connecting communities, until 2030 at a minimum. Previous studies have shown that without adequate backup power supply, the majority of the Wataynikaneyap connecting communities would experience a decrease in reliability, in terms of outage frequency and duration, than they do currently. Hydro One Remotes has been an active participant in the backup working group and recognizes that communal backup power will enhance reliability, mitigate health and safety concerns as well as protect community assets; therefore, Remotes supports the implementation of backup power until 2030. After five years of full transmission operation, in 2028 or thereabouts, we suggest the working group reconvene to review the efficacy of backup power and future funding commitments.

At the request of OSLP, Hydro One Remotes has provided two reports; "Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities" report ("Remotes Report-2018"), dated December 2018, and the Containerized DGS Option Annex ("Remotes Report-Annex"), dated November 2019. Both reports provided insight and analysis into the potential backup power in connecting communities.

For existing Hydro One served communities, with the exception of North Caribou, Remotes supports the re-use of existing Hydro One generation facilities as backup power. The existing Hydro One assets continue to have long-term importance in supporting power reliability to our communities.

Unfortunately, without excessive investment, the North Caribou diesel station is unsuitable for long-term backup operation given the plant age, number of assets reaching end of life, the current use of temporary First Nation owed generation assets and existing environmental contamination. For North Caribou, Remotes supports either the containerized DGS or the Indigenous Services Canada (ISC) funded critical community assets only options as well as a joint party environmental remediation of the site.

For the Independent Power Authority (IPA) communities of Poplar Hill, North Spirit Lake, Keewaywin, Wunnimun, Summer Beaver and Muskrat Dam; Hydro One DGS Remotes is willing to re-purpose its existing generators and provide community backup power until 2030, provided a variety of terms and conditions are met prior to transfer.

Remotes would be willing to operate the IPA stations under a fixed term operating agreement, where ownership of the assets, site decommissioning and remediation costs remain with the First Nation. The IPA station will need to be in sound operating condition and compliant with all applicable laws, regulations and standards. It is expected that the First Nation and ISC would be fully responsible for all transitional costs to achieve sound operating condition and compliance related to re-purposing a DGS, as well as, completing comprehensive Environmental Site Assessments at or near the transfer date. Remotes will not accept responsibility for contaminations that occurred prior to their takeover of DGS operations. Based on the Environmental Site Assessments, Operating Agreements may reflect one or more of the following: actions to address the contamination; Remotes being released from any liabilities associated with contaminations that occurred prior to Remotes takeover; and agreement on responsibility should contaminations occur after Remotes takeover.

Page 674 of 798

hydro one
Partners in Powerful Communities

Where the conditions are met, Remotes would be responsible for operations, maintenance and any like for like replacement capital costs. Although not expected, capital capacity increases would not be the responsibility of Remotes. It is also assumed that ISC would remain committed to backup power for critical infrastructure (water and wastewater treatment facilities, lift stations, nursing station, and nurse residence); however, community wide backup would replace the need for additional backup at community gathering spots (e.g. schools) and fire halls.

For Pikangikum, Remotes supports either the containerized DGS or the ISC-funded critical community assets only options for the community, given no usable diesel assets remain.

For Wawakapewin, Remotes supports further discussion with the community and its advisors about service options given the small community size, logistical challenges and most importantly limited community access. If a suitable access and service solution is found, Remotes will support either the containerized DGS or the ISC-funded critical community assets only backup options, given the current state of generation assets.

In all situations where Remotes has stated support for either the containerized DGS or the ISC-funded critical community assets only backup options, Remotes' preference is to provide all customers in the community with safe, reliable power.

Additionally, Remotes' license will need to be amended by the Ontario Energy Board (OEB) to allow for the generation and distribution of power for backup purposes. Remotes will apply to the OEB in our 2023 rate filing to recover costs for the provision of backup service through the Rural or Remote Rate Electricity Rate Protection (RRRP) program. Should the OEB not support the use of the RRRP for those costs we will be unable to provide backup services as described above.

We trust that this will confirm our commitment to backup power and help guide the path forward. We look forward to continuing to work with you on the backup project for the benefit of all customers.

Sincerely,

Kraemer Coulter
Managing Director
Hydro One Remote Communities Inc.

cc. Patrick Boileau, pboileau@northvista.ca
Richard Habinski, rlhabinski@xplornet.com
Jody Knibbs, jody.knibbs@canada.ca
Rachelle Boone, rachelle.boone@canada.ca
Kevin Courtney, kevin.courtney@canada.ca
Michelle Piano, michelle.piano2@canada.ca
Christopher Goode, christopher.goode@ontario.ca
Justine Desmond, justine.desmond@ontario.ca
Naomi Martin, naomi.martin@hydroone.com
Kevin Mann, kevin.mann@hydroone.com

Appendix J – Backup Power Precedents in Ontario

Five Nations Energy

Five Nations Energy Inc. is the corporation behind the Omushkego Ishkotayo Project, a 270 km of 115 kV transmission line that services the remote communities of Fort Albany, Kashechewan and Attawapiskat with Moosenee Hydro One's facility. Kashechewan Power Corporation and Attawapiskat Power Corporation (two provincially-licensed local distributors) retained the existing DGS assets to provide community backup power in Kashechewan and Attawapiskat. The DGS in Fort Albany was decommissioned when it reached its end of life. Diesel generators are rarely used since a section of the transmission line was doubled in 2015. DGS capacity has not increased while the load/demand has increased due to residents converting to electrical heating, thus sequential load shedding was required during extended outages from the grid.

Existing DGS are owned by the respective community and operated by their local distribution company (LDC). Maintenance of the generators is shared between the LDCs and Five Nations Energy Inc., the transmission line operator.

Anwaatin

In 2017-18, Anwaatin Inc. ("Anwaatin") intervened in Hydro One's rate application and brought forward a motion asking the OEB to further consider its evidence regarding extremely disparate and inadequate transmission system reliability in First Nation communities in Northern Ontario and the significant negative impacts of the very poor transmission reliability in the Anwaatin communities.

Anwaatin requested that part of Hydro One's approved capital budget be earmarked to remedy the outdated, outlier transmission assets that are causing the very poor reliability issues in the Anwaatin communities. Anwaatin represents Aroland First Nation, MoCreebec Eeyoud, and Waaskiinaysay Ziibi Inc. Development Corporation ("WZI"), an economic development corporation representing five First Nations in the Lake Nipigon watershed: Animbiigoo Zaagiigan Anishinaabek, Bingwi Neyaashi Anishinaabek, Biinjitiwaabik Zaaging Anishinaabek, Red Rock Indian Band, and Whitesand First Nation.

Anwaatin and Hydro One developed a Settlement Proposal, which was accepted by the OEB. Some of the key outcomes from the Settlement Proposal include:

- Hydro One undertaking a pilot project that is intended to explore the feasibility of implementing non-wires distributed energy projects ("Pilot Project") in and around the Anwaatin First Nation communities as a means to improve reliability in remote and radial areas of Hydro One's system. The Pilot Project is intended to provide Hydro One with an opportunity to assess whether similar and repeatable approaches may be used in other remote areas of its system that are experiencing poor reliability conditions.
- Hydro One's investment in the Pilot Project shall not exceed $5 million and shall be funded from Hydro One's distribution capital investment plan.
- Anwaatin and Hydro One agreed to work together in an effort to offset or augment this investment amount by obtaining government funding through subsidies or grant programs.

Page 676 of 798

- The Parties acknowledge that any further funding of this initiative is dependent on (i) the feasibility of the Pilot Project and (ii) further review and approval by the OEB to increase Hydro One's approved capital investment envelope and recovery through rates of the additional funding requirements.
- Anwaatin First Nation communities and Abundant Solar Energy plan to jointly develop and implement up to 45 MW of feed-in-tariff (FIT) contracted solar generation
- Hydro One will consider the feasibility of having this solar generation used as a source of supply to the energy storage facilities as part of the Pilot Project.
- Anwaatin and Hydro One will consult and cooperate on any other longer-term wires and/or non-wires electricity reliability proposals and solutions affecting the Anwaatin First Nation communities and may jointly pursue other projects intended to improve reliability in other regions served by Hydro One.

<u>Pelee Island</u>

Pelee Island is located on Lake Erie, near Windsor, and receives power via a submarine cable approximately 24 kilometres in length. Hydro One was able to provide backup generation on Pelee Island by virtue of an exemption granted to it by Ontario Regulation 71/02, made under the *Electricity Act, 1998*, and gazetted March 30, 2002, which amended Ontario Regulation 160/99. The rationale supporting the decision to implement backup power on Pelee Island is protection of residents from impacts resulting from outages, particularly during the winter months. Outages experienced by Pelee Island residents have typically lasted weeks to months. There are approximately 100 full-time residents on Pelee Island during the winter and as many as 500 during the summer.

Page 677 of 798

DRAFT COMMUNITY BAND COUNCIL RESOLUTION FOR BACKUP POWER
(for a community currently being served by **Hydro One Remote Communities Inc.)**

WHEREAS: A meeting was held with ■ Chief and Council on [DATE] (and the community on [DATE]) to discuss the Backup Power Plan and requirements once the Wataynikaneyap Power LP Project ("Watay") connects our community to the provincial electrical power grid;

WHEREAS: ■ First Nation is currently an off-grid community served by Hydro One Remote Communities Inc. ("Remotes");

AND WHEREAS: At a shareholder meeting of 2472881 Ontario Ltd., the General Partner of First Nation LP, held on December 18, 2018, a resolution was passed supporting community wide backup power until 2030 at a minimum (A copy of the resolution is attached here as Schedule "A");

AND WHEREAS: There are concerns that, once connected to the grid, there is the potential of an increased number of power outages as a result of the remoteness and radial nature of the transmission lines that will provide grid power to the communities;

AND WHEREAS: Indigenous Services Canada's ("ISC") "Level of Service Standards for Electric Power Supply and Distribution Systems" supports dedicated standby power only for critical infrastructure in communities where quality and reliability of power are a concern. Critical infrastructure consists of water treatment plant, wastewater treatment system including lift stations, school (or other emergency gathering point), nursing station, nurse residence(s), as well as fire hall;

AND WHEREAS: When centralized backup for the entire community is in place, ______ First Nation acknowledges that the standby backup power at a community gathering point (eg: school, community centre, band office, etc.), and fire hall will not be supported by ISC.

AND WHEREAS: It is the intent that centralized backup be in place at no cost to the community;

AND WHEREAS: Remotes has indicated an interest in continuing to operate and maintain its existing diesel generating site for the purpose of providing backup power to the community provided that a suitable agreement can be reached by all parties to accomplish this;

AND WHEREAS: ■ First Nation acknowledges that Remotes has accepted full responsibility for any existing soil and groundwater at the existing diesel generating site and will continue to monitor and manage their environmental responsibilities;

THEREFORE, BE IT RESOLVED THAT: ■ First Nation supports the repurposing of the Remotes diesel generating site and equipment systems for the purpose of providing a centralized backup power supply to the community until 2030 at a minimum as outlined in the Backup Power Plan; and

FURTHER BE IT RESOLVED THAT: Any costs related to the provision of backup power supply to the community will not be the responsibility of the First Nation.

Page 678 of 798

DRAFT COMMUNITY BAND COUNCIL RESOLUTION FOR BACKUP POWER

(for **IPA** communities**)**

WHEREAS: A meeting was held with ■ Chief and Council on [DATE] (and the community on [DATE]) to discuss the Backup Power Plan and requirements once the Wataynikaneyap Power LP Project ("Watay") connects our community to the provincial electrical power grid;

WHEREAS ■ First Nation is currently a community whose power is generated and distributed by a community-owned Independent Power Authority (the "IPA");

AND WHEREAS: At a shareholder meeting of 2472881 Ontario Ltd., the General Partner of First Nation LP, held on December 18, 2018, a resolution was passed supporting community wide backup power until 2030 at a minimum (A copy of the resolution is attached here as Schedule "A");

AND WHEREAS: There are concerns that, once connected to the grid, there is the potential of an increased number of power outages as a result of the remoteness and radial nature of the transmission lines that will provide grid power to the communities;

AND WHEREAS: Indigenous Services Canada's ("ISC") "Level of Service Standards for Electric Power Supply and Distribution Systems" supports dedicated standby power only for critical infrastructure in communities where quality and reliability of power are a concern. Critical infrastructure consists of water treatment plant, wastewater treatment system including lift stations, school (or other emergency gathering point), nursing station, nurse residence(s), as well as fire hall;

AND WHEREAS: When centralized backup power for the entire community is in place, ____ First Nation acknowledges that standby backup power at the community gathering point (eg: school, community centre, band office etc.) and fire hall will not be supported by ISC.

AND WHEREAS: It is the intent that centralized backup be in place at no cost to the community;

AND WHEREAS: Hydro One Remote Communities Inc. ("Remotes") has indicated an interest in operating and maintaining the current diesel generation assets of the IPA for the purpose of providing backup power to the community provided that a suitable agreement can be reached by all parties to accomplish this;

AND WHEREAS: ■ First Nation acknowledges that Remotes will have no environmental responsibility or liability for any pre-existing soil and groundwater contamination at the IPA's diesel generating site identified by an environmental site assessment report;

THEREFORE, BE IT RESOLVED THAT: ■ First Nation supports the repurposing of the community owned diesel generating site and equipment systems for the purpose of providing a centralized backup power supply to the community until 2030 at a minimum as outlined in the Backup Power Plan; and

FURTHER BE IT RESOLVED THAT: Any costs related to the provision of backup power supply to the community will not be the responsibility of the First Nation.

Page 679 of 798

Schedule "A"

MOTION #07: **Moved by** **Chief Eno H. Anderson**
Seconded by **Chief Jacob Strang**

WHEREAS 22 First Nations are the shareholders of 2472881 Ontario Limited (the "Corporation"), and 2472881 Ontario Limited is the General Partner of First Nation LP ("FNLP");

AND WHEREAS the Indigenous people will continue to exercise s. 35 Aboriginal and Treaty rights according to our understanding of the spirit and intent of the Treaty as passed down to us by our elders, and also to exercise our inherent rights given to us by the Creator, across all of our homelands;

AND WHEREAS FNLP has contracted with Opiikapawiin Services LP ("OSLP") to provide various services relating to the Wataynikaneyap Transmission Project;

AND WHEREAS due to the length and remoteness of the Wataynikaneyap Transmission Project, there are risks of power outages, which negatively impact the wellbeing of First Nations communities;

AND WHEREAS the May 2018 BBA Report estimated the reliability of the Wataynikaneyap transmission lines, evaluated backup options, and recommended utilization of existing generators as the best potential near-term backup power solution;

AND WHEREAS the December 2018 Hydro One Remotes Report recommends that existing community diesel generation assets be repurposed to provide centralized backup power in each community until 2030, as a minimum;

AND WHEREAS the Parallel Process Agreement includes a commitment by Canada to additional planning on backup power, to be completed in 2019.

THEREFORE, BE IT RESOLVED THAT Opiikapawiin Services LP will participate in the planning process identified in the Parallel Process Agreement, with the position that community wide backup power will be required in each of the First Nations to be connected by Wataynikaneyap Power, until 2030 as a minimum. The Backup Power Plan and commitments will need to address environmental responsibility and concerns, on a community by community basis, including all past and present grievances relating to historical environmental contaminations at the generator sites.

FINALLY, BE IT RESOLVED THAT ISC shall be responsible for all costs associated with all environmental remediation and clean up.
– CARRIED

Page 680 of 798

Appendix G

Remotes REG Letter & IESO Comment Letter

Hydro One
Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

BY EMAIL

July 12, 2022

Ms. Miriam Heinz
IESO
Station A, Box 4474,
Toronto, ON
M5W 4E5
Miriam.Heinz@ieso.ca

Re: Hydro One Remotes - IESO Letter of Comment Request REG projects

Dear Ms. Heinz:

Hydro One Remote Communities Inc. (Remotes) is presently preparing its 2023 Cost of Service Rate Application including the finalization of its 2023-2027 Distribution System Plan (DSP) for submittal to the Ontario Energy Board (OEB).

In accordance with the OEB's *Chapter 5 – Filing Requirements for Electricity Distribution Rate Applications – 2022 Edition for 2023 Rate Applications*, dated April 28, 2022, Remotes is expected to coordinate with the IESO in relation to Renewable Energy Generation (REG) investments proposed in the DSP and demonstrate coordination by a comment letter provided by the IESO, to be filed with the DSP.

Remotes actively engages with the IESO on REG projects as required and has prepared this letter to confirm the IESO's awareness of the potential REG projects which may materialize in Remotes' service territory over the 2023-2027 DSP period.

Background

Remotes currently generates and distributes electricity to customers in 21 off-grid communities and is also the distributor to one community connected to the province's electricity grid (Pikangikum First Nation). Cat Lake (currently served by Hydro One Networks), and six additional communities, which are currently unregulated Independent Power Authorities (IPAs), are anticipated to be added to Remotes' service area by the end of 2024, and 16 remote communities are expected to be connected to the Wataynikaneyap (Watay) transmission grid connection project over the DSP period.

REG Projects

Requests for REG connections to both off-grid and on-grid communities are accommodated through Remotes' Renewable Energy Innovation Diesel Emission Reduction "REINDEER" Program, which accommodates two types of projects:

1. "Stand-Alone" projects get paid for energy production according to a calculated rate per kilowatt generated. Available for grid-connected and non-grid connected communities.
2. "Net Metering" projects will receive a reduced monthly bill, and in some situations a credit that expires after 12 months. Only available for non-grid connected communities.

To date, Remotes has completed a Connection Impact Assessment for a biomass project in Whitesand First Nation and has assisted the First Nation and the IESO with technical design aspects of the proposed project. The Whitesand project team continues to work towards a potential 2025/26 installation. In addition, Remotes is working with Neskantaga First Nation (Lansdowne House) and developers on a proposed large scale Biomass facility. Interest in other renewable projects remains strong but there is nothing concrete at this time.

The REG projects noted above are being planned within off-grid communities which are not expected to connect to the provincial grid. In addition, there are currently no constraints on Remotes' distribution system that would prevent the connection of REG. Therefore, other than the continued promotion of the REINDEER program, Remotes does not anticipate any forecast costs to accommodate and connect REG facilities during the DSP period. Any costs for Remotes involvement in REG projects are also paid for by the proponent of the project.

IESO Comment Letter

Remotes has prepared this letter to ensure that the IESO remains cognizant of these potential REG projects, but as noted above, these projects are being developed in off-grid communities and Remotes does not expect to encounter any system constraints or capital costs to accommodate these projects over the DSP period. Remotes is respectfully requesting the IESO provide a "Letter of Comment" to confirm that Remotes has and continues to coordinate with the IESO on an as-needed basis and that the IESO remains aware of the potential REG projects being developed within Remotes' service territory.
Remotes would greatly appreciate receiving the IESO's Letter of Comment at the earliest opportunity as Remotes will need to incorporate the feedback received into their DSP.

Given the ongoing engagement with the IESO and unique nature of Remotes' business, we trust this letter is adequate and clear for your use in the intended purpose, but should there be any associated questions or comments, please do not hesitate to contact me.

Sincerely,

Kevin Mann
Manager – Business Integration & Customer Service
Hydro One Remote Communities Inc.

IESO response to Hydro One Remote Communities Inc.
REG Investment Plan 2023 – 2027

In accordance with the Ontario Energy Board's (OEB) Chapter 5 filing requirements to submit a Distribution System Plan (DSP) with its Cost of Service application, on July 12, 2022, Hydro One Remote Communities Inc. (Remotes) sent a letter with highlights of its Renewable Energy Generation (REG) Plan to the Independent Electricity System Operator (IESO) for comment. The IESO has reviewed Remotes' REG Plan and notes that it contains no investments specific to connecting REG for the Plan period 2023 - 2027.

The IESO notes that remote communities that will be connected to the Wataynikaneyap Transmission Line are in scope of the current Northwest regional planning cyle and those that are not connected were studied as part of the first regional planning cyle and IESO Remote Connection Plan. The status of regional planning activities for these regions can be found on the IESO's website.

Remotes' REG Plan states: "Requests for REG connections to both off-grid and on-grid communities are accommodated through Remotes' Renewable Energy Innovation Diesel Emission Reduction "REINDEER" Program, which accommodates two types of projects:

1. "Stand-Alone" projects get paid for energy production according to a calculated rate per kilowatt generated. Available for grid-connected and non-grid connected communities.

2. "Net Metering" projects will receive a reduced monthly bill, and in some situations a credit that expires after 12 months. Only available for non-grid connected communities."

Further, Remotes notes that ""REG projects noted above are being planned within off-grid communities which are not expected to connect to the provincial grid. In addition, there are currently no constraints on Remotes' distribution system that would prevent the connection of REG".

The IESO submits that Remotes' REG investments during the 5-year Distribution System Plan period will not have an no impact on the provincial grid and the IESO regional planning process, no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties [1].

The IESO appreciates the opportunity provided to review the REG Plan of Remotes, and looks forward to working together further throughout the regional planning processes.

[1] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

Appendix H

Needs Assessment Report issued by HONI on July 17, 2020

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Northwest Ontario Region

Date: July 17th 2020

Prepared by: Northwest Ontario Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Northwest Ontario Region and to recommend which need may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION Northwest Ontario Region

LEAD Hydro One Networks Inc. ("HONI")

START DATE: March 10th 2020 **END DATE:** July 17th 2020

1. INTRODUCTION

For the first cycle of the Regional Planning process for the Northwest Ontario Region an Integrated Regional Resource Plan ("IRRP") was published in 2016 which identified a number of near- and mid-term needs. The planning process was completed in June 2017 with the publication of the Regional Infrastructure Plan ("RIP") which provided a description of needs and recommendations of preferred wires plans to address near-term needs. The RIP also identified some near- and mid-term needs that will be reviewed during this Regional Planning cycle.

The purpose of this Needs Assessment ("NA") is to identify any new needs and to reaffirm needs identified in the previous Northwest Ontario Regional Planning cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous Integrated Regional Resource Plan ("IRRP") and RIP reports as well as new replacement/ refurbishment needs in the Northwest Ontario Region, the 2nd Regional Planning cycle was triggered for this Region.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous RIP; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs.
- Identify needs that will require further coordination at the regional level and those which can be met more directly by distributors and other customers as their respective transmitter.

The Study Team may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One provided input and relevant information for the Northwest Ontario Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL").

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical infrastructure needs, recommend further mitigation or action plan(s) to address these needs, and determine whether further regional coordination or broader study would be beneficial.

The assessment reviewed available information including load forecasts, conservation and demand management ("CDM") and distributed generation ("DG") forecasts, reliability needs, operational issues, and major high voltage equipment identified to be at or near the end of their useful life and requiring replacement/refurbishment.

A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- Reliability needs and operational concerns; and
- Any major high voltage equipment reaching the end of its useful life.

6. NEEDS

I. Update on Needs Identified from Previous Cycle

- E1C (Ear Falls Transformer Station ("TS") x Crow River DS) / Red Lake TS Near Capacity – The new 230kV Watay connection between Pickle Lake Switching Station ("SS") and Dinorwic Junction ("Jct") will provide relief to the capacity constraint on E1C by 2021
- A4L Capacity Increase to Accommodate Mining Development in the Geraldton Area – Geraldton Area mining development activities have not fully materialized
- New wires to accommodate Energy East Pipeline and Ring of Fire – Due to cancellation of Energy East Pipeline project and uncertainties associated with developments at the Ring of Fire, this need has not yet materialized
- Additional Capacity Anticipated on the Dryden 115kV Sub-System by mid-2020s – The updated 2029 forecast for Dryden 115kV Sub-System is 80MW. Under this growth

assumption, the Load Meeting Capability ("LMC") is sufficient to meet the demand of this sub-system.

- Kenora Municipal Transformer Station ("MTS") Supply Need - The forecasted load growth at Kenora MTS is anticipated to reach 23MW by year 2027, which is also near the station's 10-Day Limited Time Rating ("LTR").
- Moose Lake 115kV and Fort Frances 115kV Sub-System Supply Capacity – The updated load forecast indicate sufficient supply capacity to meet demands at these two sub-systems within the West of Thunder Bay Sub-Region
- Port Arthur TS #1 Transformation Capacity – Once the Low Voltage ("LV") yard refurbishment is complete in 2025, the capacity will increase to 59MW. The total station load is forecasted to be around 45MW in year 2029, which is still well below the revised station LTR of 59MW.

II. New Needs Identified in the Region

- Lakehead TS Capacity Need – With the significant load increase and substantial decrease in dependable generation output assumption[1] in the Thunder Bay Sub-Region, voltage support will be required to prevent voltage collapse under N-1-1 Contingency Scenario (i.e.: Loss of Lakehead auto-transformers T7 and T8), while at the same time mitigation is required to prevent overloading of the 115kV circuits A5A, A1B, and T1M under this outage condition.
- Marathon TS – With the significant load increase and substantial decrease in dependable generation output assumption[1] in the Greenstone-Marathon Sub-Region, under N-1-1 contingency (i.e: loss of both auto-transformers at Marathon TS), the Greenstone-Marathon Sub-Region system experiences voltage collapse. Even with additional voltage support to resolve the voltage issue, the 115kV circuit A5A could be overloaded at peak load conditions.
- Sapawe DS – This station is a 115/12.5kV distribution station owned by Hydro One Distribution. The station has a Winter Planned Loading Limit (PLL) of 4.30MW and a Summer PLL of 3.42MW (assuming 0.9 power factor), and its load growth is anticipated to reach these levels by year 2028 and 2026 respectively.
- Sam Lake DS –The station is the sole supply for Sioux Lookout Hydro, and this embedded LDC is anticipating to have significant load increase up to 35MW throughout the next 10 year period. The existing transformation facility at Sam Lake DS

[1] In future studies, the total hydro output of all facilities within a sub-system will be summed before calculating the 98% dependable output in order to reflect a more accurate assessment of the capacity need.

has already reached its Winter 10-Day LTR, and various options including adding an additional step-down transformer or having a brand new station built in the vicinity are being considered. Due to the significant load increase, additional voltage support is also needed at this station.

III. EOL Asset Replacements and Refurbishments

- Projects Under Execution:
  - i. Birch TS – High Voltage ("HV") Breaker, Disconnect Switch, and Insulator Replacement
  - ii. Dryden TS – New 115/44kV Step-Down Transformers & HV Breaker Replacement
  - iii. Fort Frances MTS – HV Breaker Replacement
  - iv. Pine Portage SS – HV Breaker & Disconnect Switch Replacements
- New Station Projects:
  - i. Alexander SS – HV Breaker and Line Disconnect Switch Replacement
  - ii. Ear Falls TS – HV Breaker Replacement
  - iii. Fort Frances TS - HV Breaker & 230/115kV Step-Down Auto-Transformer Replacement
  - iv. Kenora TS – HV Circuit Breaker, Switch Replacement, 230/115kV Step-Down Auto-Transformer Replacement
  - v. Lakehead TS – HV Breaker, Switch and Protection & Control Facility Replacement
  - vi. Mackenzie TS – HV Breaker, Line Disconnect Switch, 230/115kV Step-Down Auto-Transformer Replacement
  - vii. Marathon TS – HV Breaker and Line Disconnect Switch Replacement
  - viii. Moose Lake TS - 115/44kV Step-Down Transformer Replacement
  - ix. Port Arthur TS #1 – LV Yard Replacement
  - x. Rabbit Lake SS – New HV Load Break Switch Install; HV Breaker & Disconnect Switch, Line Disconnect Switch Replacement
  - xi. Whitedog Falls SS – HV Breaker, Line Disconnect Switch Replacement
- New Line Projects:
  - i. 115kV A4L Circuit – Beardmore Jct x Longlac TS Refurbishment

ii. 115kV E1C Circuit – Ear Falls TS x Slate Falls DS Refurbishment; Etruscan Jct x Crow River DS Refurbishment

7. RECOMMENDATIONS

The Study Team's recommendations for the above identified needs are as follows:

a) E1C (Ear Falls TS x Crow River DS) / Red Lake TS Near Capacity – No actions required at this time, but it is prudent to continue to monitor the Red Lake Area load and growth-related activities.

b) A4L Capacity Increase to Accommodate Mining Development in the Geraldton Area – No actions required at this time other than to continue to monitor the Geraldton Area Mining Development.

c) New wires to accommodate Energy East Pipeline and Ring of Fire – No actions required at this time other than to continue to monitor the Ring of Fire development.

d) Additional Capacity Anticipated on the Dryden 115kV Sub-System by mid-2020s – Further regional coordination will be required in order to study different growth scenarios and the resulting impact they may have on the Dryden 115kV Sub-System.

e) Kenora MTS Capacity Need – No further regional coordination is required as Synergy North will take the lead to further assess the need in co-ordination with Hydro One Transmission as part of the Local Planning ("LP"). However, this need may be revisited at a later date should additional findings during subsequent phases of Regional Planning trigger the Study Team to reconsider the recommendation made in the NA phase.

f) Lakehead TS Capacity Need – IESO will take the lead to further study the need throughout SA and IRRP stages of the Regional Planning in order to determine a preferred solution.

g) Marathon TS Capacity Need – IESO will take the lead to further study the need throughout SA and IRRP stages stages of the Regional Planning in order to determine a preferred solution.

h) Sapawe DS Capacity Need – Hydro One Distribution will take the lead to look into this need in co-ordination with Hydro One Transmission as part of the Distribution Planning.

i) Sam Lake DS Capacity Need – Since no upstream system voltage and flow violations are observed, no further regional coordination is required. Sioux Lookout Hydro, Hydro One Distribution and Hydro One Transmission will collaborate in order to develop a suitable solution to address this need as part LP. However, this need may be revisited at a later date should additional findings during subsequent phases of Regional Planning trigger the Study Team to reconsider the recommendation made in the NA phase.

j) Based on this region's sensitivity to industrial load growth scenarios as seen in the 1st cycle of IRRP, it is prudent to review those affected sub-regions starting with an IESO-led Scoping Assessment. This will help in verifying any changes in assumptions with respect to anticipated industrial loads in those regions.

k) The implementation and execution for the replacement of the EOL transmission assets will be coordinated between Hydro One Transmission and the affected LDCs, where required. These projects will be coordinated with the IESO when required and where feasible within the timelines afforded by each project.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

The first cycle of the Regional Planning process for the Northwest Ontario Region was completed in June 2017 with the publication of the Regional Infrastructure Plan (“RIP”). The RIP provided a description of needs and recommendations of preferred wires plans to address near- and medium-term needs.

The purpose of this Needs Assessment (“NA”) is to identify new needs and to reconfirm needs identified in the previous Northwest Ontario Regional Planning cycle. Since the previous Regional Planning cycle, some new needs in the region have been identified.

This report was prepared by the Northwest Ontario Region Study Team (“Study Team”), led by Hydro One Networks Inc. Participants of the Study Team are listed below in Table 1. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies (“LDC”) and the Independent Electricity System Operator (“IESO”).

Table 1: Northwest Ontario Region Study Team Participants

Company
Atikokan Hydro Inc.
Fort Frances Power Corporation
Hydro One Networks Inc. (Distribution)
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator (“IESO”)
Sioux Lookout Hydro Inc.
Synergy North

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least every five years. In light of the timing of the needs identified in the previous Integrated Regional Resource Planning ("IRRP") and RIP reports as well as new replacement/ refurbishment identified needs in the Northwest Ontario Region, the 2nd Regional Planning cycle was triggered for the Northwest Ontario region.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Northwest Ontario Region and includes:

- Identification of new needs based on latest information provided by the Study Team; and,
- Confirmation/updates of existing needs and/or plans identified in the previous planning cycle.

The Study Team may identify additional needs during the next phases of the Regional Planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

Bulk electrical supply to the Northwest Ontario Region is provided through a combination of local generation stations connected to the 230 kV and 115 kV network, and the East-West Tie transmission corridor.

The Local Distribution Companies ("LDCs") that serve the electricity demands for the Northwest Ontario are Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Sioux Lookout Hydro Inc., Synergy North, and Fort Frances Power Corporation ("FFPC"). The LDCs receive power at the step down transformer stations ("TS") and distribute it to the end users – industrial, commercial and residential customers.

The January 2015 IRRP report for North of Dryden Sub-Region, the June 2016 IRRP report for Greenstone-Marathon Sub-Region, the July 2016 IRRP report for West of Thunder Bay Sub-Region, and the December 2016 IRRP report for Thunder Bay Sub-Region focused on northern, eastern, western, and central parts, respectively, of the Region. All IRRP reports were prepared by the IESO in conjunction with Hydro One and the LDCs. A map and a single line diagram showing the electrical facilities of the Northwest Ontario Region, consisting of the sub-regions, is shown in Figure 1 and Figure 2, respectively.

North of Dryden Sub-Region

A radial single-circuit 115 kV transmission line ("E4D") supplies electricity to the customers in the North of Dryden sub-region from Dryden TS. A new 230 kV transmission line between Dinorwic (~40 km southeast of Dryden) to Pickle Lake, along with associated station facilities, are currently under construction. The major supply station for this sub-region is Dryden TS, where the voltage is stepped down from the 230 kV to 115 kV, to serve local and industrial customers. Electricity demand in the North of Dryden sub-region is also supplied by local hydroelectric generation.

Greenstone-Marathon Sub-Region

Electrical supply to the customers in the Greenstone-Marathon Sub-Region comprises of Marathon TS and Alexander Switching Station ("SS"). Marathon TS steps down 230 kV to 115 kV and supplies customers in the Town of Marathon, White River and Manitouwadge through a 115 kV single circuit - M2W. Three circuits A5A, A1B, and T1M - in series connect Marathon TS to Alexander SS.

Alexander SS connects Alexander Generating Station ("GS"), Cameron Falls GS, and Pine Portage GS - to the system. A 115 kV single-circuit A4L, connected to the Alexander SS, supplies electricity to the Municipality of Greenstone and its surrounding areas. Nipigon GS is also connected to the circuit A4L.

West of Thunder Bay Sub-Region

Supply to this Sub-Region is provided from a 230 kV transmission system consisting of the Kenora TS, Fort Frances TS, Dryden TS, and Mackenzie TS. Kenora TS steps down 230 kV to 115 kV and supplies customers in the City of Kenora and surrounding areas. In addition, it also connects Ontario to Manitoba's electrical system through two 230 kV transmission lines – K21W and K22W. Fort Frances TS steps down 230 kV to 115 kV and supplies customers in the City of Fort Frances and surrounding areas. It also connects Ontario to Minnesota's electrical system through a 115 kV transmission line – F3M. Dryden TS steps down 230 kV to 115 kV and supplies customers in the City of Dryden and surrounding areas. It also connects West of

Thunder Bay to North of Dryden Sub-Region. Mackenzie TS steps down 230 kV to 115 kV and supplies customers in Atikokan and surrounding areas. It also connects West of Thunder Bay to the Thunder Bay Sub-Region. The West of Thunder Bay Sub-Region is also supplied by many local hydroelectric generation facilities

Thunder Bay Sub-Region

Thunder Bay Sub-Region consists of the Lakehead TS as the 230 kV step-down transformation facility which steps down 230 kV to 115 kV and supplies customers in the City of Thunder Bay and surrounding areas. The area is served primarily at 115 kV by three step-down transformer stations - Birch TS, Fort William TS, and Port Arthur TS #1.

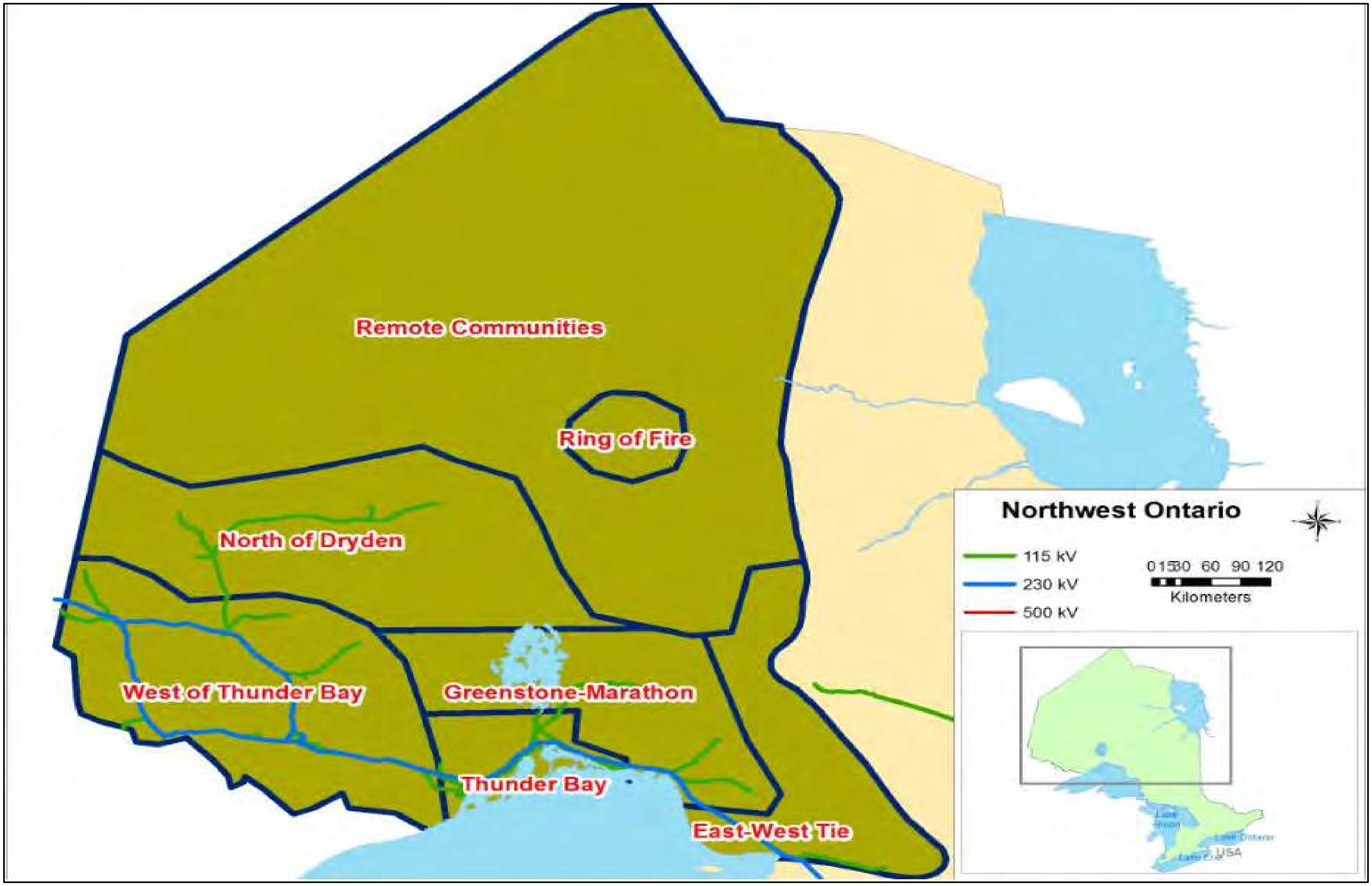


Figure 1 - Northwest Ontario Region Map

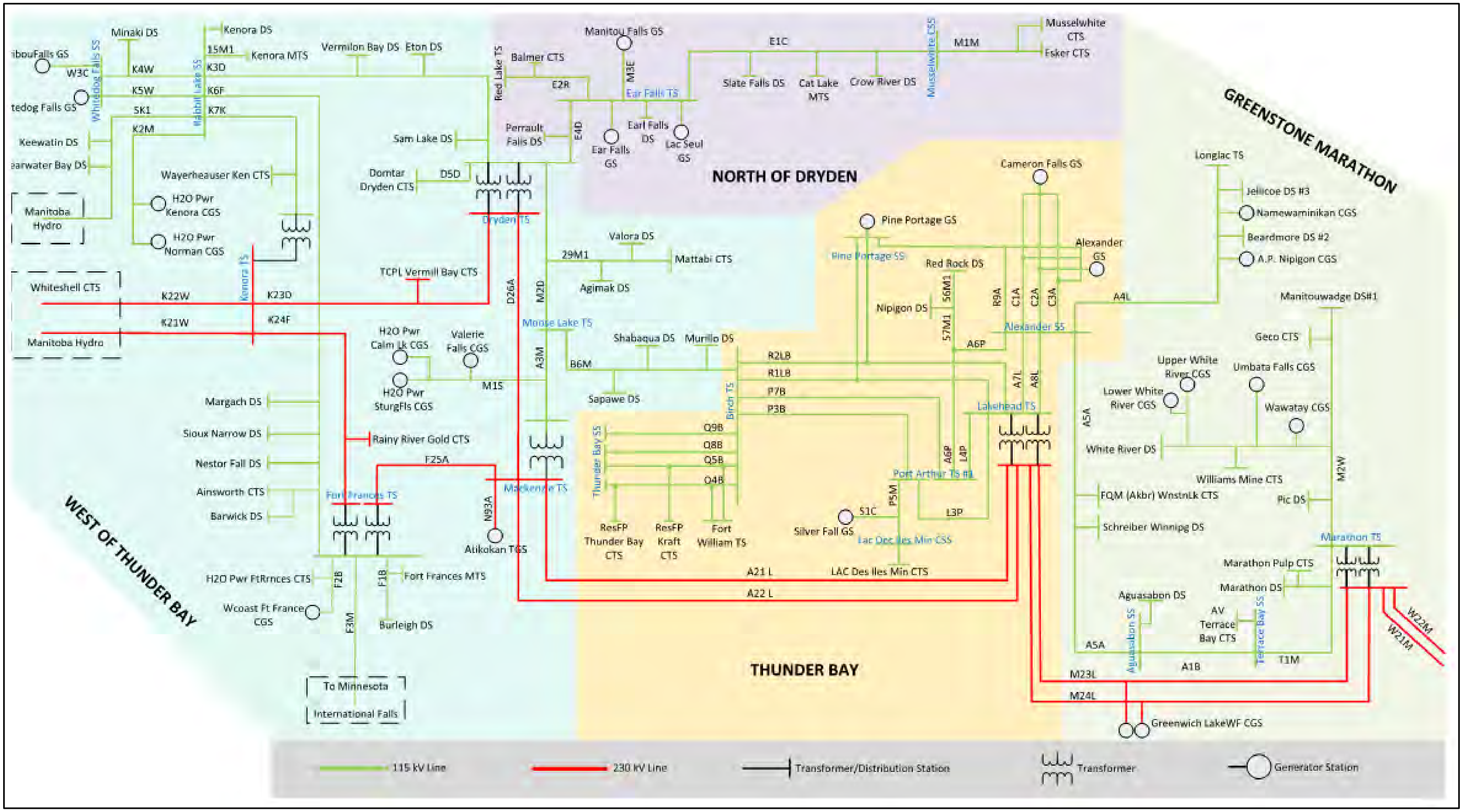


Figure 2 - Single Line Diagram for Northwest Ontario Region

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Northwest Ontario Region NA Report. The information provided includes the following:

- Northwest Ontario Region Load Forecast for all supply stations;
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the Northwest Ontario Region.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

Information gathering included:

i. Load forecast: The relevant LDCs provided load forecasts for their respective load supply stations in the Northwest Ontario Region for the ten (10) year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the Northwest Ontario Region. The region's extreme winter and summer non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast load growth rates to the actual 2019 winter and summer peak extreme weather corrected loads, with Hydro One providing extreme weather correction factors. The net extreme weather summer and winter load forecasts were then produced by subtracting the percentage CDM reduction, and the amount of effective DG capacity from each station's gross load forecast. These extreme weather winter and summer load forecasts for the individual stations in the Northwest Ontario Region are given in Appendix A;

ii. Relevant information regarding system reliability and operational issues in the region; and

iii. List of major High Voltage ("HV") transmission equipment planned and/or identified to be refurbished and/or replaced due to the EOL which is relevant for Regional Planning purposes. This includes HV transformers, auto-transformers, HV breakers, HV underground cables and overhead lines.

A technical assessment of needs was undertaken based on:

- Planning criteria outlined in IESO-ORTAC (section 2.7.1) for analysis of current and future transmission system adequacy (critical N-1-1 contingencies for assessing load supply reliability);
- Planning criteria outlined in IESO-ORTAC (section 2.7.2) for analysis of current and future station capacity and transmission adequacy;
- Planning criteria outlined in IESO-ORTAC (section 7) for load reliability;
- System reliability and operational concerns; and
- Any major high voltage equipment reaching EOL.

In addition, the following assumptions were made in this Needs Assessment Report:

1) The new East-West Tie Transmission Reinforcement is included in the assessment model

2) The new 230kV circuit to be built by Wataynikaneyap Power between Watay 230/115kV TS and Dinorwic Jct on 230kV circuit D26A is assumed to be in-service

3) 115kV circuit E1C is sectionalized at Placer Jct to accommodate the connection of Hydro One owned 115kV Pickle Lake SS, which in turn is connected to the new Watay TS. As a result, the section of E1C from Pickle Lake SS to Musselwhite Customer Switching Station ("CSS") is being renamed as C2M:
    a. 115kV C2M (Pickle Lake SS x Musselwhite CSS)
    b. 115kV E1C (Ear Falls TS x Pickle Lake SS)

4) Ten (10) remote First Nation communities north of Pickle Lake are electrically supplied by Watay TS

5) Six (6) remote First Nation communities north of Red Lake are electrically supplied by Wataynikaneyap Power owned Switching Station that taps onto Hydro One owned 115kV circuit E2R adjacent to Balmer Jct

6) Inter-tie flows between Ontario and Manitoba on 230kV circuits K21W and K22W are reduced to near zero

7) Inter-tie flows between Ontario and Minnesota on 115kV circuit F3M is reduced to near zero

8) The Northwest Ontario Region is winter peaking, and the 2029 Winter Load Forecast is used in the simulation study

9) The assessment of transmission system adequacy is conducted using the winter non-coincident forecasts

10) Adequacy of transformation capacity at load stations was assessed assuming a 0.9 lagging power factor and non-coincident station loads for both summer and winter forecasts[2]

11) Hydroelectric generation is assumed to be at 98% dependable when all elements are in service, as well as during N-1 contingency analysis as per IESO's ORTAC documentation. Generation is assumed to be at 85% dependable when one transmission element is out of service pre-contingency[3]

7 NEEDS

This section describes emerging needs identified in the Northwest Ontario Region, and also reaffirms the near, mid, and long-term needs already identified in the previous Regional Planning cycle.

7.1 Review of Needs Identified in the Previous Cycle of Regional Planning

This section review the status of the needs identified in the previous cycle of Region Planning as summarized in Table 2 below, followed by detailed analysis of select needs from the table.

---

[2] Please see Appendices A & B more more details

[3] Please see Appendix C for more details

Table 2: Needs Identified in the Previous Regional Planning Cycle

Type of Needs identified in the previous RP cycle	Needs Details	2020 Update
North of Dryden Sub-Region		
115kV Line Capacity	E1C (Ear Falls TS x Crow River DS) Near Capacity	The new 230kV Watay connection between Pickle Lake SS and Dinorwic Jct will provide relief to the capacity constraint on E1C by 2021
115kV Line Capacity	Red Lake Sub-System Near Capacity	The new 230kV Watay connection between Pickle Lake SS and Dinorwic Jct will provide relief to the capacity constraints on E4D and E2R. This additional capacity will be made available to serve the growths of Red Lake area loads
Greenstone-Marathon Sub-Region		
115kV Line Capacity	A4L Capacity Increase to Accommodate Mining Development in the Geraldton Area	Geraldton Area mining development activities have not fully materialized. The Study Team will continue to monitor the mining development in the Geraldton Area.
230kV Line Capacity	New 230kV transmission circuit / switching station and 230/115kV Auto-Transformer	Cancellation of Energy East Pipeline project and uncertainties surrounding Ring of Fire developments have resulted in the need not being materialized. However, the Study Team will continue to monitor the Ring of Fire developments.
West of Thunder Bay Sub-Region		
230/115kV Transformation Capacity	Additional Capacity Anticipated on the Dryden 115kV Sub-System by mid-2020s	The updated 2029 forecast for the Dryden 115kV Sub-System and the North of Dryden Sub-Region are forecasted at 80MW and 97MW respectively[4]. Under these growth assumptions, the LMC is sufficient to meet the demand of this sub-system.
115kV Station Capacity	Kenora MTS – Capacity Need	The forecasted load growth at Kenora MTS is anticipated to reach 23MW by year 2027, which is near the station's 10-Day LTR.

[4] As per West of Thunder Bay IRRP from the first planning cycle, Dryden 115kV Sub-System can provide up to 240MW of continuous supply to Dryden 155kV Sub-System and North of Dryden Sub-Region. The updated forecasted demand for these two systems is 177MW, and this is a significant decline from the IRRP forecast of 310MW.

Type of Needs identified in the previous RP cycle	Needs Details	2020 Update
115kV Station & Line Capacities	Moose Lake 115kV Sub-System Supply Capacity	No actions were recommended in the 1st cycle IRRP due to sufficient supply capacity to meet demand in the planning horizon. The updated load forecast also indicate sufficient supply capacity to meet demands at Moose Lake TS, Sapawe DS, and Shabqua DS.
115kV Station & Line Capacities	Fort Frances 115kV Sub-System Supply Capacity	No actions were recommended in the 1st cycle IRRP due to sufficient supply capacity to meet demand in the planning horizon. The updated load forecast also indicate sufficient supply capacity to meet demands at load stations along 115kV K6F, F1B and F2B circuits.
Thunder Bay Sub-Region		
115kV Station Capacity	Port Arthur TS #1 – Transformation Capacity	Once the station LV yard refurbishment is complete in 2025, the capacity will increase to 59MW. The total station load is forecasted to be around 45MW in year 2029, which is still well below the station's 10-Day LTR of 59MW.
230/115kV Transformation Capacity	Lakehead TS – Capacity Need	Due to significant growths in Thunder Bay and Greenstone-Marathon Sub-Regions, the forecasted load in the Thunder Bay 115kV System has exceeded the IRRP's High Scenario forecast from the previous planning cycle and has therefore escalated the need.

E1C (Ear Falls TS x Crow River DS) Near Capacity / Red Lake Sub-System Near Capacity

The North of Dryden IRRP from the previous planning cycle has indicated that the 115kV circuit E1C from Ear Falls TS to the Pickle Lake area has reached capacity. At the same time, the Red Lake Sub-System Load Meeting Capability ("LMC") may be insufficient to meet the needs of mining loads.

However, the new 230kV circuit to be built by Wataynikaneyap Power between Pickle Lake and Dinorwic Jct on 230kV circuit D26A will provide relief to the capacity constraint on E1C and E4D. Hydro One is in the process of constructing a new 115kV switching station at Pickle Lake to connect E1C circuit to the new 230kV circuit via a new 230/115kV auto-transformer station. The anticipated completion date is mid-2021.

No actions are required at this time, and the Study Team will continue to monitor the Red Lake Area load growth related activities.

Additonal Capacity Anticipated on the Dryden 115kV Sub-System by mid-2020s

The West of Thunder Bay IRRP from the previous planning cycle has indicated that under high load growth scenario, additional capacity of 50MW will be required on the Dryden 115kV Sub-System by mid-2020s. The IRRP has indicated that the Dryden 115kV Sub-System can provide up to 240MW of continuous supply to Dryden 155kV Sub-System and North of Dryden Sub-Region.

As per the current load forecast, the Dryden 115kV Sub-System is forcasted to be 80MW, and the North of Dryden Sub-Region is forecasted at 97MW. The total demand from these two systems is 177MW, and this is a significant decline from the IRRP forecast of 310MW.

The Study Team recommends the further regional c to study different growth scenarios for the Dryden 115kV Sub-Sytem and the resulting impact they may present.

Kenora MTS – Capacity Need

Kenora Municipal Transformer Station (“MTS”) is a 115kV load station owned by Synergy North and its forecasted load growth is anticipated to reach 23MW by year 2027, which is also the station’s Winter 10-Day Limited Time Rating (“LTR”). Please see **Section 7.2** for more details.

Port Arthur TS #1 – Transformation Capacity Need

Port Arthur TS #1 is a 115/25kV load station located just east of the City of Thunder Bay, supplying Hydro One Distribution and Synergy North customers. Due to equipment limitations and assets reaching EOL at the low voltage side of the station, the station has historically been limited to provide up to 55MW. However, once the Low Voltage ("LV") yard refurbishment is complete in year 2025, the station capacity will revert back to 59MW. As per the latest load forecast, the updated station capacity will be able to accommodate both Hydro One Distribution and Synergy North load growths up to and beyond year 2029.

The Study Team recommends no actions to be taken at this time.

Lakehead TS – Capacity Need

Lakehead TS is a cirtical 230/115kV Step-Down Transformation Station located approximately 7km east of the City of Thunder Bay. The Thunder Bay Sub-Region IRRP from the previous cycle has indicated that under high growth scenario, the Thunder Bay Sub-Region would require additional supply capacity of 20MW by year 2030. However, the latest load forecast indicates the demand has significantly increased in the Thunder Bay Sub-Region and at the same time the dependable generation output has significantly decreased. Please see **Section 7.2** for more details.

7.2 Assessment of New Findings on Station and Transmission Capacities in the Northwest Ontario Region

230/115kV Auto-Transformation Facilities

Kenora TS

No capacity and voltage concerns when 230/115kV auto-transformer T1 is in-service.

Upon observing N-1 auto-transformer contingency, loadings on all 230kV, 115kV and remaining auto-transformers in the Northwest Ontario Region are kept within their respective 10-Day LTRs. Bus voltages also are kept within change limits criteria as per Section 4.3 – Voltage Change Limits from ORTAC.

Mackenzie TS

No capacity and voltage concerns when 230/115kV auto-transformer T3 is in-service.

Upon observing N-1 auto-transformer contingency, loadings on all 230kV, 115kV and remaining auto-transformers in the Northwest Ontario Region are kept within their respective 10-Day LTRs. Bus voltages also are kept within change limits criteria as per Section 4.3 – Voltage Change Limits from ORTAC.

Dryden TS

No capacity and voltage concerns when both 230/115kV auto-transformers T22 and T23 are in-service.

Upon observing N-1 auto-transformer contingency, the loading on the remaining auto-transformer is within its 10-Day Limited Time Ratings (LTRs). Loadings on all 230kV, 115kV and remaining auto-transformers in the Northwest Ontario Region are kept within their respective 10-Day LTRs. Bus voltages also are kept within change limits criteria as per Section 4.3 – Voltage Change Limits from ORTAC.

Upon observing N-1-1 auto-transformer contingency[5], loadings on all 230kV, 115kV and remaining auto-transformers in the Northwest Ontario Region are kept within their respective 10-Day LTRs. Bus voltages also are kept within change limits criteria as per Section 4.3 – Voltage Change Limits from ORTAC.

Fort Frances TS

No capacity and voltage concerns when both 230/115kV auto-transformers T1 and T2 are in-service.

Upon observing N-1 auto-transformer contingency, the loading on the remaining auto-transformer is within its 10-Day Limited Time Ratings (LTRs). Loadings on all 230kV, 115kV and remaining auto-transformers in the Northwest Ontario Region are kept within their respective 10-Day LTRs. Bus voltages also are kept within change limits criteria as per Section 4.3 – Voltage Change Limits from ORTAC.

Upon observing N-1-1 auto-transformer contingency, loadings on all 230kV, 115kV and remaining auto-transformers in the Northwest Ontario Region are kept within their

[5] The loss of the second auto-transformer was simulated at Dryden TS and at other 230/115kV supply stations in the Northwest Ontario Region.

respective 10-Day LTRs. Bus voltages also are kept within change limits criteria as per Section 4.3 – Voltage Change Limits from ORTAC.

Lakehead TS

No capacity and voltage concerns when both Lakehead 230/115kV auto-transformers T7 and T8 are in-service.

Upon observing N-1 auto-transformer contingency, the loading on the remaining auto-transformer is within its 10-Day Limited Time Ratings (LTRs). Loadings on all 230kV, 115kV and remaining auto-transformers in the Northwest Ontario Region are kept within their respective 10-Day LTRs. Bus voltages also are kept within change limits criteria as per Section 4.3 – Voltage Change Limits from ORTAC.

With the significant load increase and substantial decrease in dependable generation output assumption in the Thunder Bay Sub-Region, voltage support will be required to prevent voltage collapse under N-1-1 Contingency Scenario (i.e.: Loss of Lakehead auto-transformers T7 and T8), while at the same time mitigation is required to prevent overloading of the 115kV circuits A5A, A1B, and T1M under this outage condition.

The Study Team recommends the IESO to take the lead in conducting further studies in SA and IRRP stages of Regional Planning in order to determine a preferred solution.

Marathon TS

No capacity and voltage concerns when both Marathon 230/115kV auto-transformers T11 and T12 are in-service.

Upon observing N-1 auto-transformer contingency, the loading on the remaining auto-transformer is within its 10-Day Limited Time Ratings (LTRs). Loadings on all 230kV, 115kV and remaining auto-transformers in the Northwest Ontario Region are kept within their respective 10-Day LTRs. Bus voltages also are kept within change limits criteria as per Section 4.3 – Voltage Change Limits from ORTAC.

With the significant load increase and substantial decrease in dependable generation output assumption in the Greenstone-Marathon Sub-Region, upon observing N-1-1 contingency (i.e. loss of both Marathon auto-transformers), the Greenstone-Marathon Sub-Region system experiences voltage collapse unless voltage support or load reduction is implemented. Without load reduction there will be overload on 115kV circuit A5A.

The Study Team recommends the IESO to take the lead in conducting further studies in SA and IRRP stages of Regional Planning in order to determine a preferred solution.

115kV Connection Facilities

Voltage performance for the 115kV connection facilities is within ORTAC guidelines upon experiencing N-1 and N-1-1 contingencies. Based on the demand forecast, there is sufficient transformation and circuit capacity throughout the study period for 115kV connected load stations with the following exceptions:

Kenora MTS

Kenora MTS is a 115kV substation owned by Synergy North, and it is located approximately 1.4km southeast of Rabbit Lake SS. Kenora MTS has a Winter 10-Day LTR of 23.40MW (assuming 0.9 power factor), and its load growth is anticipated to reach this level by year 2027.

The Study Team recommends the decision to expand / modify Kenora MTS in order to accommodate load growth past 2027 be made by Synergy North in co-ordination with Hydro One as part of the LP. However, this need may be revisited at a later date should additional findings during subsequent phases of Regional Planning trigger the Study Team to reconsider the recommendation made in the NA phase.

Sapawe DS

Sapawe DS is a 115/12.5kV distribution station owned by Hydro One Distribution, and it is located approximately 2.4km northeast of Sapawe Jct on 115kV circuit B6M. Sapawe DS has a Winter Planned Loading Limit (PLL) of 4.30MW and a Summer PLL of 3.42MW (assuming 0.9 power factor), and its load growth is anticipated to reach these levels by year 2028 and 2026 respectively.

Hydro One Distribution will look into this as part of its Distribution Planning.

Murillo DS

Murillo DS is a 115/25kV distribution station owned by Hydro One Distribution, and it is located immediately south of Murillo Jct on 115kV circuit B6M. As of 2019, the load has already reached the station's PLL, however due to OPG owned Kakabeka GS generating at the LV side of Murrillo DS, the 115/25kV step-down transformer is in reverse flow most of the time.

No further actions are required at this time.

Sam Lake DS

Sam Lake DS is a Hydro One owned 115/25kV distribution station located 75km northeast of Dryden TS, feeding off from 115kV circuit K3D. The station is the sole supply for Sioux Lookout Hydro, and this embedded LDC is anticipated to have significant load increase up to 35MW throughout the next 10 year period. The existing transformation facility at Sam Lake DS has already reached its Winter 10-Day LTR, and various options including adding an additional step-down transformer or having a new station built in the vicinity are being be considered. Due to the significant load increase, additional voltage support will also be required at this station in order to address the post-contingency voltage decline issue and to satisfy ORTAC's Voltage Change Limits requirements.

Since no upstream system voltage and flow violations are observed, no further regional coordination is required. The Study Team recommends Sioux Lookout Hydro, Hydro One Distribution and Hydro One Transmission to collaborate in order to develop a suitable solution to address this need as part the LP. However, this need may be revisited at a later date should additional findings during subsequent phases of Regional Planning trigger the Study Team to reconsider the recommendation made in the NA phase.

115kV Transmission Lines

M2W

M2W pre-contingency voltage levels are relatively low (at around 114kV) in the vicinity of White River DS due to reduced hydroelectric generation output assumptions at Gitchi Animki GS and Umbata Falls CGS, and increased load forecast at industrial sites along

M2W and White River DS. However with the use of ULTC the customers are not expected to experience low voltage at the LV bus.

No further actions are required at this time, and Hydro One will continue to closely monitor the voltage levels along M2W.

Q4B

Due to significant increase in industrial loads feeding from 115kV circuit Q4B, voltages along this circuit are in the vicinity of 116kV pre-contingency. In addition, with increased load forecast at Ft. Williams TS, additional voltage support maybe required locally.

No further actions are required at this time, and Hydro One will continue to closely monitor the voltage levels along Q4B.

Load Security

As per Section 7.1 – Load Security Criteria of IESO's ORTAC documentation:

With all transmission facilities in service, equipment loading must be within continuous ratings, voltages must be within normal ranges and transfers must be within applicable normal condition stability limits. This must be satisfied coincident with an outage to the largest local generation unit.

Assessment:

Under each of the simulated outage scenarios[6], all equipment are within their continuous ratings, voltages are within normal ranges.

[6] The largest generation output (assuming 85% Generation Dependability) was taken out in each of the four sub-regions:

1) West of Thunder Bay Sub-Region: Whitedog Falls GS – 3 Units O/S
2) North of Dryden Sub-Region: Manitou Falls GS – 4 Units O/S
3) Greenstone-Marathon Sub-Region: Aguasabon GS O/S
4) Thunder Bay Sub-Region: Pine Portage GS – 2 Units O/S

With any one element out of service, equipment loading must be within applicable long-term emergency ratings, voltages must be within applicable emergency ranges, and transfers must be within applicable normal condition stability limits. Planned load curtailment or load rejection, excluding voluntary demand management, is permissible only to account for local generation outages. Not more than 150MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management.

Assessment:
Upon N-1 contingencies in the Northwest Ontario Region (including 115kV and 230kV lines, 230/115kV autotrasformers and 115kV step-down transformers), equipment loading are within applicable long-term emergency ratings, voltages are within applicable emergency ranges as per ORTAC's Section 4.3 – Voltage Change Limits. Not more than 150MW is loss by configuration or load rejection.

With any two elements out of service, voltages must be within applicable emergency ranges, equipment loading must be within applicable short-term emergency ratings and transfers must be within applicable emergency condition stability limits. Equipment loading must be reduced to the applicable long-term emergency ratings in the time afforded by the short-time ratings. Planned load curtailment or load rejection exceeding 150MW is permissible only to account for local generation outages. Not more than 600MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management.

Assessment:
The simultaneous loss of two adjacent circuits on a common tower does not result in interruption of more than 600 MW of load by either configuration, planned load curtailment or load rejection. It also does not result in post-contingency voltage and equipment loading violations. More specifically, the study included the following scenarios:

- P3B and P7B between Port Arthur TS #1 and Birch TS
- R1LB and R2LB between Pine Portage, Lakehead TS and Birch TS
- A7L and A8L between Lakehead TS and Alexander SS

Furthermore, the simultaneous loss of two (2) 230/115 kV auto-transformers does not interrupted more than 600 MW of load by configuration or by planned load curtailment or load rejection. However, as previously discussed, post-contingency voltage and loading levels resulting from loss of Marathon TS and Lakehead TS auto-transformers do not meet criteria.

Load Restoration

The Northwest Ontario Region has multiple radial single circuit and/or single transformer connected load stations where load loss is anticipated after a single transformer and/or single circuit contingency. At these locations ORTAC restoration criteria of 8 hours may not always be met. Impacted radial single circuits include, but not limited to:

- 115kV A4L (Alexander SS x Longlac TS)
- 115kV M2W (Marathon TS x White River DS)
- 115kV E2R (Ear Falls TS x Red Lake TS)
- 115kV C2M (Pickle Lake SS x Musselwhite CSS)
- 115kV K3D (Sam Lake DS x Dryden TS)
- 115kV 29M1 (Ignace Jct x Mattabi CTS)
- 115kV M1S (Moose Lake TS x Crilly DS)
- 115kV A6P/56M1/57M1 (Alexander SS x Port Arthur TS x Red Rock DS)
- 115kV P5M/S1C (Port Arthur TS x Lac Des Iles Mine CTS)

There may be a need to review load restoration reliability for these circuits, especially given that lengthy restoration times and aging HV circuits can contribute to greater socio-economic costs for local communities in Northern Ontario than those in Southern Ontario where more opportunities exist to switch to alternate supplies when a HV circuit is out of service. During the IRRP phase, the IESO will take the lead in conducting additional studies and to engage with local communities as necessary.

7.3 End-of-Life Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Auto-transformers
- Power transformers
- HV and LV breakers
- Transmission lines
- Protection Systems

Accordingly, following major high voltage equipment has been identified as approaching its EOL over the next 10 years.

Table 3: EOL Equipment – Northwest Ontario Region

Station / Circuit	Scope of Work	Replacement/ Refurbishment Timing	Details
Projects Under Execution			
Birch TS	• HV Breaker, Disconnect Switch, and Insulator Replacement	2020	These projects are discussed further in **Section 7.3.1**
Dryden TS	• Two (2) New Standard 115/44kV Step-Down Transformers to replace Three Existing (3) Non-Standard 115/44kV Step-Down Transformer • HV Breaker Replacement	2020	
Fort Frances MTS	• HV Breaker[7] Replacement	2020	
Pine Portage SS	• HV Breaker, Disconnect Switch and Protection & Control Facilities Replacement	2020	

[7] FFPC-owned asset

Newly Identified Station Projects			
Alexander SS	• HV Breaker and Line Disconnect Switch Replacement	2022	These projects are discussed further in **Section 7.3.2**
Ear Falls TS	• HV Breaker Replacement	2022	
Fort Frances TS	• HV Breaker Replacement • Two (2) 230/115kV Step-Down Auto-Transformer Replacement	2027	
Kenora TS	• HV Circuit Breaker, Switch Replacement • One (1) 230/115kV Step-Down Auto-Transformer Replacement	2025	
Lakehead TS	• HV Breaker, Switch and Protection & Control Facility Replacement	2025	
Mackenzie TS	• HV Breaker, Line Disconnect Switch • One (1) 230/115kV Step-Down Auto-Transformer Replacement	2024	
Marathon TS	• HV Breaker and Line Disconnect Switch Replacement	2024	
Moose Lake TS	• Two (2) 115/44kV Step-Down Transformer Replacement • One (1) 44kV Breaker Replacement	2024	
Port Arthur TS #1	• LV Yard Replacement	2025	
Rabbit Lake SS	• New HV Load Break Switches	2022	
	• HV Breaker & Disconnect Switch, Line Disconnect Switch Replacement	2024	
Whitedog Falls SS	• HV Breaker, Line Disconnect Switch Replacement	2023	

Newly Identified Line Projects			
115kV A4L	• Beardmore Jct x Longlac TS	2022	These projects are discussed further in **Section 7.3.3**
115kV E1C	• Ear Falls TS x Slate Falls DS Refurbishment • Etruscan Jct x Crow River DS Refurbishment	2025	

The EOL assessment for the above high voltage equipment typically included consideration of the following options:

1. Maintaining the status quo;
2. Replacing equipment with similar equipment of lower ratings and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
6. Replacing equipment with higher ratings and built to current standards; and
7. Station reconfiguration

Maintaining status quo is not an option for any of the above EOL auto-transformer, station transformer or line sections due to risk of equipment failure, would result in increased maintenance cost and customer outages. Replacing "Like-for-Like" with nonstandard transformers would result in complexity with failures and difficulty in getting similar spare equipment along with their installation. Nonstandard equipment also poses serious safety risk for employees under normal and emergency situations.

7.3.1 EOL Projects Under Execution

The following EOL refurbishment project is currently under execution. Since the completion of the first Regional Planning cycle, the need for proceeding with this project arose before the initiation of the second Regional Planning cycle. Hence, the following project was not listed or discussed during the first cycle of Regional Planning and are currently in execution:

Birch TS

Birch TS is a 115kV-connected load supply station in the City of Thunder Bay serving Synergy North customers. It is supplied by multiple 115kV connections from Lakehead TS and Mackenzie TS. The existing 115kV breakers, disconnect switches, and insulators are at EOL, and Hydro One is planning to replace them before end of 2020.

Dryden TS

Dryden TS is a critical transformer station in the West of Thunder Bay Sub-Region and it consists of two (2) 230/115kV, 75/100/125MVA auto-transformers supplied by 230kV circuits D26A and K23D. The 115kV station yard supplies multiple load stations via K3D circuit to West of Thunder Bay Sub-Region and E4D circuit to North of Dryden Sub-Region. In addition, the 115kV yard supplies Hydro One Distribution customer via three (3) non-standard 115/44kV, 15 MVA step-down transformers. The non-standard step-down transformers are being replaced with two (2) new standard 115/44kV, 42 MVA transformers along with 115kV breakers. This work is anticipated for completion before end of 2020.

Fort Frances MTS

Fort Frances MTS is a 115kV connected load supply station serving the Town of Fort Frances in the Rainy River District. It is owned by FFPC and supplied by 115kV circuit F1B emanating from Fort Frances TS. The existing 115kV HV breaker at Fort Frances MTS is at EOL, and FFPC is planning to replace it before end of 2020.

Pine Portage SS

Pine Portage SS is a 115kV switching station located within the OPG owned Pine Portage GS, and approximately 120km northeast of Lakehead TS. The switching station terminates three 115kV circuits and connects 144MW of hydroelectric generation on the Nipigon River. The existing 115kV breakers, line disconnect switches, and protection & control equipment are at EOL through visual inspections and diagnostic testing. The anticipated replacement date is before end of 2020.

7.3.2 Newly Identified EOL Station Refurbishment Projects

The following EOL station refurbishment needs have been identified in the current Regional Planning cycle:

Alexander SS

Alexander SS is a 115kV switching station that was constructed in 1955 and is considered a critical asset in the Northwest. This station is connected to OPG-owned Alexander GS, and it has five (5) 115kV circuits for the supply of customers in the south. The existing HV breaker and line disconnect switches have reached EOL, and there are plans in place to replace them by year 2022.

Ear Falls TS

Ear Falls TS is a 115kV supply station located approximately 100km northwest of City of Dryden. Presently Ear Falls TS has four incoming and outgoing 115 kV circuits: E2R, M3E, E4D and E1C connecting the Ear Falls TS to Red Lake TS, Manitou Falls GS, Dryden TS and Cat Lake MTS, respectively. Ear Falls TS also connects to OPG-owned Lac Seul GS and Ear Falls GS, and it feeds Ear Falls DS via a 115kV step-down transformer. The existing HV breaker at the station is reaching EOL, and the anticipated replacement year is 2022.

Fort Frances TS

Fort Frances TS is a critical 230/115kV supply station located in the Town of Fort Frances. Multiple 115kV circuit emanates from this station including F1B, F2B, K6F, and F3M which ties into Minnesota. The two (2) 230/115kV Step-Down Auto-Transformer and 115kV breakers at the station are reaching EOL, and the plan to replacement them is scheduled for 2027.

Kenora TS

Kenora TS is a critical 230/115kV supply station located approximately 9km east of City of Kenora. It consists of one (1) 230/115kV step-down auto-transformer, and in turn it supplies the northwest portion of the West of Thunder Bay Sub-Region. The existing step-down auto-transformer, as well as HV breakers and switches are reaching EOL, and these are to be replaced by year 2025.

Lakehead TS

Lakehead TS is a critical 230/115kV step-down transformer station in-serviced in 1955 and is located approximately 4km east of the City of Thunder Bay. The station consists of a 230kV and an 115kV switchyard connected by two 250MVA auto-transformers. The existing HV breakers, switches, and Protection & control facilities at the station are approaching EOL, and the anticipated replacement year is 2025.

Mackenzie TS

Mackenzie TS is a 230/115kV supply station in-serviced since 1972 and it is located just south of Town of Atikokan. The station consists of a 230kV yard and supplies 115kV circuit A3M via a 230/115kV, 125MVA auto-transformer. The existing 230/115kV auto-transformer, as well as HV breakers and line disconnect switches are near EOL, and Hydro One has plans to replace them by year 2024.

Marathon TS

Marathon TS is a critical 230/115kV supply station located just outside of the Town of Marathon. This station provides supply to the Greenstone-Marathon Sub-Region via two (2) 230/115kV step-down auto-transformers. The existing HV breakers at this station is approaching EOL, and there are plans to replace these by year 2024.

Moose Lake TS

Moose Lake TS is a 115kV connected load supply station approximately 8km north of the Town of Atikokan, and it the sole supply station for Atikokan Hydro customers. The existing two (2) 115/44kV Step-Down Transformer and LV breakers are near EOL, and Hydro One is looking at replacing them by 2024.

Port Arthur TS #1

Port Arthur TS #1 is a 115kV connected load station located on the north-eastern edge of the City of Thunder Bay. The station consists of two (2) 115/25kV step-down transformers and it supplies both Hydro One Distribution and Synergy North customers. Due to equipment limitations and EOL assets on the LV side of the station, the station has been limited to provide up to 55MW. Once the LV yard refurbishment is complete in 2025, the station capacity will increase to 59MW.

Rabbit Lake SS

Rabbit Lake SS was originally built in 1956 and it is located within the city limits of Kenora. The station consists of a 115kV switchyard with six (6) 115kV circuits. It provides supply to Synergy North-owned Kenora MTS, and Hydro One Distribution-owned Kenora DS. New HV load break switch installs are due for completion in 2022, while the existing HV breaker / disconnect switches, and line disconnect switches are also near EOL and plans are in place to replace them by 2024.

Whitedog Falls SS
Whitedog Falls SS is a 115kV-connected switching station located approximately 45km northwest of the City of Kenora. It is connected to multiple 115kV circuits including K4W, K5W extending to Rabbit Lake SS, W3C from Caribou Falls GS, and locally it directly connects to OPG-owned Whitedog GS. The existing 115kV breakers, and line disconnect switches at the station are near EOL, and Hydro One is planning to replace them in 2023.

7.3.3 Newly Identified EOL Line Refurbishment Projects

The following EOL line refurbishment needs have been identified in the current Regional Planning cycle:

115kV A4L
115kV A4L is a 150km radial circuit running between Alexander SS and Longlac TS. Conductors stringing the section between Beardmore Jct and Longlac TS was constructed in 1937 and therefore have reached EOL as per laboratory test results. It is anticipated that the refurbishment of this section is due for completion in year 2022.

115kV E1C
115kV E1C is a 260km radial circuit running between Ear Falls TS and Musselwhite CSS. Along this circuit, sections of Ear Falls TS x Slate Falls DS and Etruscan Jct X Crow River DS have reached EOL as per laboratory testing, and as a result, have been prescribed for full line refurbishment. Both of these line section were constructed in 1939 and have therefore reached 77 years of age. It is anticipated that the refurbishment of both sections are due for completion in year 2025.

8 CONCLUSION AND RECOMMENDATIONS

The Study Team's recommendations for the above identified needs are as follows:

a) E1C (Ear Falls TS x Crow River DS) / Red Lake TS Near Capacity – No actions required at this time, but it is prudent to continue to monitor the Red Lake Area load and growth-related activities.

b) A4L Capacity Increase to Accommodate Mining Development in the Geraldton Area – No actions required at this time other than to continue to monitor the Geraldton Area Mining Development.

c) New wires to accommodate Energy East Pipeline and Ring of Fire – No actions required at this time other than to continue to monitor the Ring of Fire development.

d) Additional Capacity Anticipated on the Dryden 115kV Sub-System by mid-2020s – Further regional coordination will be required in order to study different growth scenarios and the resulting impact they may have on the Dryden 115kV Sub-System.

e) Kenora MTS Capacity Need – No further regional coordination is required as Synergy North will take the lead to further assess the need in co-ordination with Hydro One Transmission as part of the Local Planning ("LP"). However, this need may be revisited at a later date should additional findings during subsequent phases of Regional Planning trigger the Study Team to reconsider the recommendation made in the NA phase.

f) Lakehead TS Capacity Need – IESO will take the lead to further study the need throughout SA and IRRP stages of the Regional Planning in order to determine a preferred solution.

g) Marathon TS Capacity Need – IESO will take the lead to further study the need throughout SA and IRRP stages stages of the Regional Planning in order to determine a preferred solution.

h) Sapawe DS Capacity Need – Hydro One Distribution will take the lead to look into this need in co-ordination with Hydro One Transmission as part of the Distribution Planning.

i) Sam Lake DS Capacity Need – Since no upstreamsystem voltage and flow violations are observed, no further regional coordination is required. Sioux Lookout Hydro, Hydro One Distribution and Hydro One Transmission will collaborate in order to develop a suitable solution to address this need as part LP. However, this need may be revisited at a later date should additional findings during subsequent phases of Regional Planning trigger the Study Team to reconsider the recommendation made in the NA phase.

a) Based on this region's sensitivity to industrial load growth scenarios as seen in the 1st cycle of IRRP, it is prudent to review those affected sub-regions starting with an IESO-led Scoping Assessment. This will help in verifying any changes in assumptions with respect to anticipated industrial loads in those regions.

b) The implementation and execution for the replacement of the EOL transmission assets will be coordinated between Hydro One Transmission and the affected LDCs, where required. These projects will be coordinated with the IESO when required and where feasible within the timelines afforded by each project.

9 REFERENCES

Appendix A: Northwest Ontario Region Non-Coincident Winter Load Forecast

* LTR/PLL based on 0.9 power factor

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Greenstone-Marathon Sub-Region												
Longlac TS	Hydro One Distribution (Gross Forecast)	13.34	15.49	16.25	20.43	20.56	20.68	20.82	14.96	15.11	15.25	42.84
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.02	0.06	0.09	0.12	0.13	0.09	0.09	0.10	
	Net Load (Normal Weather Corrected)	13.34	15.48	16.23	20.36	20.47	20.56	20.69	14.87	15.02	15.16	
	Net Load (Extreme Weather Corrected)	14.21	16.48	17.28	21.68	21.79	21.89	22.03	15.83	15.99	16.14	
Manitouwadge TS	Hydro One Distribution (Gross Forecast)	10.05	10.15	10.26	10.39	11.86	11.95	12.06	12.17	12.28	12.39	37.53
	DG (Incremental)	8.00	8.00	8.00	8.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.03	0.05	0.07	0.07	0.08	0.08	0.08	
	Net Load (Normal Weather Corrected)	2.05	2.14	2.25	2.36	11.81	11.89	11.98	12.10	12.21	12.31	
	Net Load (Extreme Weather Corrected)	2.18	2.28	2.40	2.51	12.57	12.65	12.76	12.88	13.00	13.11	
Beardmore DS #2	Hydro One Distribution (Gross Forecast)	1.28	1.29	1.31	1.32	1.34	1.35	1.36	1.37	1.39	1.40	10.80
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	
	Net Load (Normal Weather Corrected)	1.28	1.29	1.30	1.32	1.33	1.34	1.35	1.37	1.38	1.39	
	Net Load (Extreme Weather Corrected)	1.36	1.37	1.39	1.40	1.42	1.43	1.44	1.45	1.47	1.48	
Jellicoe DS #3	Hydro One Distribution (Gross Forecast)	0.56	0.72	0.72	0.73	0.73	0.73	0.73	0.74	0.74	0.74	2.16

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	Net Load (Normal Weather Corrected)	0.56	0.72	0.72	0.72	0.72	0.73	0.73	0.73	0.74	0.74	
	Net Load (Extreme Weather Corrected)	0.60	0.76	0.77	0.77	0.77	0.77	0.78	0.78	0.78	0.79	
Manitouwadge DS #1	Hydro One Distribution (Gross Forecast)	1.34	1.35	1.36	1.37	0.00	0.00	0.00	0.00	0.00	0.00	8.64
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	Net Load (Normal Weather Corrected)	1.34	1.35	1.36	1.37	0.00	0.00	0.00	0.00	0.00	0.00	
	Net Load (Extreme Weather Corrected)	1.42	1.43	1.44	1.45	0.00	0.00	0.00	0.00	0.00	0.00	
Marathon DS	Hydro One Distribution (Gross Forecast)	7.67	7.76	7.87	7.98	8.07	8.15	8.24	8.33	8.43	8.52	10.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.02	0.04	0.05	0.05	0.05	0.05	0.05	
	Net Load (Normal Weather Corrected)	7.67	7.76	7.86	7.96	8.03	8.10	8.19	8.28	8.38	8.47	
	Net Load (Extreme Weather Corrected)	8.17	8.26	8.37	8.47	8.55	8.63	8.72	8.82	8.92	9.02	
Pic DS	Hydro One Distribution (Gross Forecast)	5.43	5.48	5.55	5.62	5.67	5.72	5.78	5.84	5.90	5.96	10.80
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.02	0.02	0.03	0.04	0.04	0.04	0.04	
	Net Load (Normal Weather Corrected)	5.43	5.48	5.54	5.60	5.65	5.69	5.74	5.80	5.86	5.92	
	Net Load (Extreme Weather Corrected)	5.78	5.84	5.90	5.97	6.01	6.06	6.11	6.18	6.24	6.30	
Schreiber Winnipeg DS	Hydro One Distribution (Gross Forecast)	5.08	5.13	5.19	5.25	5.30	5.34	5.39	5.44	5.49	5.54	8.64
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	Net Load (Normal Weather Corrected)	5.08	5.13	5.18	5.24	5.28	5.31	5.35	5.41	5.46	5.50	
	Net Load (Extreme Weather Corrected)	5.41	5.46	5.52	5.58	5.62	5.65	5.70	5.76	5.81	5.86	
White River DS	Hydro One Distribution (Gross Forecast)	8.25	8.34	8.44	10.25	10.33	10.41	10.49	10.58	10.66	10.74	14.04
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.03	0.04	0.06	0.07	0.07	0.07	0.07	
	Net Load (Normal Weather Corrected)	8.25	8.34	8.43	10.22	10.29	10.35	10.42	10.51	10.60	10.68	
	Net Load (Extreme Weather Corrected)	8.78	8.88	8.98	10.88	10.95	11.02	11.10	11.19	11.28	11.37	
North of Dryden Sub-Region												
Red Lake TS	Hydro One Distribution (Gross Forecast)	24.79	25.19	25.61	26.05	26.44	26.83	27.23	27.65	28.07	28.48	55.35
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.01	0.03	0.08	0.11	0.15	0.17	0.17	0.17	0.18	
	Net Load (Normal Weather Corrected)	24.79	25.18	25.58	25.97	26.33	26.67	27.06	27.48	27.89	28.30	
	Net Load (Extreme Weather Corrected)	26.39	26.81	27.23	27.66	28.03	28.40	28.81	29.25	29.70	30.13	
Cat Lake MTS	Hydro One Distribution (Gross Forecast)	1.29	1.30	1.32	1.33	1.34	1.35	1.36	1.37	1.39	1.40	2.70
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	
	Net Load (Normal Weather Corrected)	1.29	1.30	1.31	1.33	1.33	1.34	1.35	1.36	1.38	1.39	
	Net Load (Extreme Weather Corrected)	1.38	1.39	1.40	1.41	1.42	1.43	1.44	1.45	1.47	1.48	
Crow River DS	Hydro One Distribution (Gross Forecast)	2.71	2.73	2.76	2.79	2.81	2.83	2.86	2.88	2.91	2.93	10.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.02	
	Net Load (Normal Weather Corrected)	2.71	2.73	2.76	2.78	2.80	2.82	2.84	2.86	2.89	2.91	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	Net Load (Extreme Weather Corrected)	2.89	2.91	2.94	2.97	2.98	3.00	3.02	3.05	3.08	3.10	
Perrault Falls DS	Hydro One Distribution (Gross Forecast)	0.46	0.47	0.47	0.48	0.48	0.49	0.49	0.50	0.50	0.51	10.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	Net Load (Normal Weather Corrected)	0.46	0.47	0.47	0.48	0.48	0.49	0.49	0.49	0.50	0.50	
	Net Load (Extreme Weather Corrected)	0.49	0.50	0.50	0.51	0.51	0.52	0.52	0.53	0.53	0.54	
Slate Falls DS	Hydro One Distribution (Gross Forecast)	0.65	0.65	0.66	0.67	0.67	0.68	0.68	0.69	0.70	0.70	4.23
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	Net Load (Normal Weather Corrected)	0.65	0.65	0.66	0.67	0.67	0.67	0.68	0.69	0.69	0.70	
	Net Load (Extreme Weather Corrected)	0.69	0.70	0.70	0.71	0.71	0.72	0.72	0.73	0.74	0.74	
Ear Falls DS	Hydro One Distribution (Gross Forecast)	5.42	5.46	5.51	5.56	5.60	5.63	5.67	5.72	5.76	5.80	10.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.02	0.02	0.03	0.04	0.04	0.04	0.04	
	Net Load (Normal Weather Corrected)	5.42	5.46	5.50	5.55	5.58	5.60	5.64	5.68	5.72	5.76	
	Net Load (Extreme Weather Corrected)	5.77	5.81	5.86	5.91	5.94	5.97	6.00	6.05	6.09	6.14	
West of Thunder Bay Sub-Region												
Barwick TS	Hydro One Distribution (Gross Forecast)	15.39	15.55	15.73	15.94	16.08	16.22	16.37	16.54	16.71	16.86	58.86
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.01	0.02	0.05	0.07	0.09	0.10	0.10	0.10	0.11	
	Net Load (Normal Weather Corrected)	15.39	15.54	15.72	15.89	16.01	16.13	16.27	16.44	16.60	16.76	
	Net Load (Extreme Weather Corrected)	16.38	16.55	16.73	16.92	17.05	17.17	17.33	17.50	17.68	17.84	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Dryden TS	Hydro One Distribution (Gross Forecast)	18.05	18.32	18.62	18.95	19.21	19.46	19.73	20.01	20.30	20.57	56.97
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.01	0.02	0.06	0.08	0.11	0.12	0.12	0.13	0.13	
	Net Load (Normal Weather Corrected)	18.05	18.32	18.60	18.89	19.12	19.35	19.60	19.89	20.17	20.45	
	Net Load (Extreme Weather Corrected)	19.22	19.50	19.81	20.11	20.36	20.60	20.87	21.18	21.48	21.77	
Fort Frances MTS	FFPC (Gross Forecast)	15.75	15.83	16.13	16.22	16.14	16.22	16.27	16.36	16.36	16.45	23.94
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.01	0.02	0.05	0.07	0.09	0.10	0.10	0.10	0.10	
	Net Load (Normal Weather Corrected)	15.75	15.83	16.12	16.17	16.07	16.13	16.17	16.25	16.26	16.34	
	Net Load (Extreme Weather Corrected)	16.77	16.85	17.16	17.21	17.11	17.17	17.22	17.31	17.32	17.40	
Moose Lake TS	Atikokan Hydro (Gross Forecast)	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	10.98
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.02	0.03	0.04	0.04	0.04	0.04	0.04	
	Net Load (Normal Weather Corrected)	6.50	6.50	6.49	6.48	6.47	6.46	6.46	6.46	6.46	6.46	
	Net Load (Extreme Weather Corrected)	6.92	6.92	6.91	6.90	6.89	6.88	6.88	6.88	6.88	6.88	
Kenora MTS	Synergy North (Gross Forecast)	19.39	20.00	20.28	20.66	20.98	21.21	21.54	21.90	22.30	22.65	23.40
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	Net Load (Normal Weather Corrected)	19.39	20.00	20.28	20.66	20.98	21.21	21.54	21.90	22.30	22.65	
	Net Load (Extreme Weather Corrected)	20.64	21.30	21.59	22.00	22.33	22.58	22.93	23.32	23.74	24.12	
Agimak DS	Hydro One Distribution (Gross Forecast)	4.96	5.01	5.07	5.14	5.18	5.23	5.28	5.34	5.39	5.44	10.80
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	CDM (Incremental)	0.00	0.00	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	
	Net Load (Normal Weather Corrected)	4.96	5.01	5.07	5.12	5.16	5.20	5.25	5.30	5.36	5.41	
	Net Load (Extreme Weather Corrected)	5.28	5.34	5.39	5.45	5.50	5.54	5.59	5.65	5.70	5.76	
Burleigh DS	Hydro One Distribution (Gross Forecast)	4.07	4.10	4.14	4.18	4.21	4.23	4.26	4.29	4.32	4.35	10.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.02	0.02	0.03	0.03	0.03	0.03	
	Net Load (Normal Weather Corrected)	4.07	4.10	4.14	4.17	4.19	4.21	4.23	4.26	4.30	4.32	
	Net Load (Extreme Weather Corrected)	4.34	4.37	4.40	4.44	4.46	4.48	4.51	4.54	4.57	4.60	
Clearwater Bay DS	Hydro One Distribution (Gross Forecast)	5.19	5.22	5.26	5.31	5.33	5.36	5.39	5.42	5.45	5.48	9.36
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	
	Net Load (Normal Weather Corrected)	5.19	5.22	5.25	5.29	5.31	5.33	5.35	5.39	5.42	5.45	
	Net Load (Extreme Weather Corrected)	5.52	5.56	5.59	5.63	5.65	5.67	5.70	5.74	5.77	5.80	
Eton DS	Hydro One Distribution (Gross Forecast)	3.69	3.72	3.76	3.80	3.83	3.85	3.88	3.92	3.95	3.98	10.80
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.02	0.02	0.02	
	Net Load (Normal Weather Corrected)	3.69	3.72	3.75	3.79	3.81	3.83	3.86	3.89	3.93	3.96	
	Net Load (Extreme Weather Corrected)	3.93	3.96	4.00	4.03	4.06	4.08	4.11	4.15	4.18	4.21	
Keewatin DS	Hydro One Distribution (Gross Forecast)	4.73	4.77	4.81	4.86	4.90	4.93	4.97	5.01	5.05	5.09	10.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.01	0.02	0.03	0.03	0.03	0.03	0.03	
	Net Load (Normal Weather Corrected)	4.73	4.76	4.81	4.85	4.88	4.90	4.94	4.98	5.02	5.05	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	Net Load (Extreme Weather Corrected)	5.03	5.07	5.12	5.16	5.19	5.22	5.26	5.30	5.34	5.38	
Margach DS	Hydro One Distribution (Gross Forecast)	8.88	8.94	9.02	9.11	9.16	9.21	9.27	9.34	9.40	9.46	10.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.03	0.04	0.05	0.06	0.06	0.06	0.06	
	Net Load (Normal Weather Corrected)	8.88	8.94	9.01	9.08	9.12	9.16	9.21	9.28	9.35	9.40	
	Net Load (Extreme Weather Corrected)	9.45	9.52	9.59	9.67	9.71	9.75	9.81	9.88	9.95	10.01	
Minaki DS	Hydro One Distribution (Gross Forecast)	0.70	0.70	0.71	0.71	0.72	0.72	0.73	0.73	0.74	0.74	10.80
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	Net Load (Normal Weather Corrected)	0.70	0.70	0.71	0.71	0.71	0.72	0.72	0.73	0.73	0.74	
	Net Load (Extreme Weather Corrected)	0.74	0.75	0.75	0.76	0.76	0.76	0.77	0.77	0.78	0.78	
Nestor Falls DS	Hydro One Distribution (Gross Forecast)	3.05	3.07	3.09	3.12	3.14	3.15	3.17	3.19	3.21	3.23	10.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.02	
	Net Load (Normal Weather Corrected)	3.04	3.06	3.09	3.11	3.12	3.14	3.15	3.17	3.19	3.21	
	Net Load (Extreme Weather Corrected)	3.24	3.26	3.29	3.31	3.33	3.34	3.36	3.38	3.40	3.42	
Sam Lake DS	Hydro One Distribution (Gross Forecast)	20.87	22.93	24.30	25.28	26.25	28.69	30.12	31.09	32.07	33.04	21.60
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.01	0.03	0.08	0.11	0.16	0.19	0.19	0.20	0.21	
	Net Load (Normal Weather Corrected)	20.87	22.92	24.27	25.20	26.14	28.53	29.93	30.90	31.87	32.84	
	Net Load (Extreme Weather Corrected)	22.22	24.41	25.85	26.83	27.83	30.37	31.87	32.90	33.93	34.96	
Sapawe DS	Hydro One Distribution (Gross Forecast)	3.78	3.81	3.85	3.90	3.93	3.96	3.99	4.02	4.06	4.09	4.32

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.02	0.03	0.03	
	Net Load (Normal Weather Corrected)	3.78	3.81	3.85	3.89	3.91	3.93	3.96	4.00	4.03	4.07	
	Net Load (Extreme Weather Corrected)	4.03	4.06	4.10	4.14	4.16	4.19	4.22	4.26	4.29	4.33	
Shabaqua DS	Hydro One Distribution (Gross Forecast)	3.59	3.61	3.63	3.66	3.68	3.69	3.71	3.73	3.75	3.77	8.64
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.02	0.02	0.02	
	Net Load (Normal Weather Corrected)	3.59	3.61	3.63	3.65	3.66	3.67	3.69	3.71	3.73	3.75	
	Net Load (Extreme Weather Corrected)	3.82	3.84	3.86	3.88	3.90	3.91	3.93	3.95	3.97	3.99	
Sioux Narrows DS	Hydro One Distribution (Gross Forecast)	4.38	4.41	4.45	4.49	4.52	4.54	4.57	4.61	4.64	4.67	10.80
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.01	0.02	0.03	0.03	0.03	0.03	0.03	
	Net Load (Normal Weather Corrected)	4.38	4.41	4.44	4.48	4.50	4.52	4.54	4.58	4.61	4.64	
	Net Load (Extreme Weather Corrected)	4.66	4.69	4.73	4.77	4.79	4.81	4.84	4.87	4.91	4.94	
Valora DS	Hydro One Distribution (Gross Forecast)	0.82	0.83	0.84	0.86	0.87	0.88	0.90	0.91	0.92	0.94	4.32
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	
	Net Load (Normal Weather Corrected)	0.82	0.83	0.84	0.86	0.87	0.88	0.89	0.91	0.92	0.93	
	Net Load (Extreme Weather Corrected)	0.87	0.88	0.90	0.91	0.92	0.94	0.95	0.96	0.98	0.99	
Vermilion Bay DS	Hydro One Distribution (Gross Forecast)	2.36	2.39	2.42	2.46	2.48	2.51	2.54	2.57	2.60	2.63	8.64
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	

Transformer Station		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		Near Term Forecast (MW)					Medium Term Forecast (MW)					
	Net Load (Normal Weather Corrected)	2.36	2.39	2.42	2.45	2.47	2.49	2.52	2.55	2.58	2.61	
	Net Load (Extreme Weather Corrected)	2.51	2.54	2.57	2.61	2.63	2.66	2.68	2.72	2.75	2.78	
Crilly DS	Hydro One Distribution (Gross Forecast)	1.95	1.97	1.99	2.02	2.04	2.05	2.07	2.09	2.11	2.13	2.16
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
	Net Load (Normal Weather Corrected)	1.95	1.97	1.99	2.01	2.03	2.04	2.06	2.08	2.10	2.12	
	Net Load (Extreme Weather Corrected)	2.08	2.10	2.12	2.14	2.16	2.17	2.19	2.21	2.24	2.26	
Kenora DS	Hydro One Distribution (Gross Forecast)	6.18	6.24	6.32	6.40	6.46	6.51	6.58	6.64	6.71	6.77	10.80
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.02	0.03	0.04	0.04	0.04	0.04	0.04	
	Net Load (Normal Weather Corrected)	6.18	6.24	6.31	6.38	6.43	6.48	6.54	6.60	6.67	6.73	
	Net Load (Extreme Weather Corrected)	6.58	6.65	6.72	6.79	6.85	6.90	6.96	7.03	7.10	7.17	
Whitedog DS	Hydro One Distribution (Gross Forecast)	2.22	2.25	2.27	2.31	2.33	2.35	2.38	2.41	2.43	2.46	2.88
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02	
	Net Load (Normal Weather Corrected)	2.22	2.24	2.27	2.30	2.32	2.34	2.37	2.39	2.42	2.45	
	Net Load (Extreme Weather Corrected)	2.36	2.39	2.42	2.45	2.47	2.49	2.52	2.55	2.58	2.60	
Thunder Bay Sub-Region												
Birch TS	Synergy North (Gross Forecast)	72.42	72.94	73.26	73.89	74.50	74.74	75.15	75.75	76.38	76.86	100.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.01	0.02	0.08	0.23	0.32	0.43	0.47	0.47	0.47	0.48	
	Net Load (Normal Weather Corrected)	72.41	72.91	73.17	73.67	74.18	74.31	74.69	75.28	75.90	76.38	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	Net Load (Extreme Weather Corrected)	77.10	77.63	77.91	78.44	78.98	79.12	79.52	80.15	80.81	81.32	
Fort Williams TS	Synergy North (Gross Forecast)	79.01	79.36	79.51	79.94	80.38	80.46	80.71	81.12	81.56	81.86	98.46
	DG (Incremental)	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	
	CDM (Incremental)	0.01	0.03	0.09	0.25	0.35	0.46	0.50	0.50	0.51	0.51	
	Net Load (Normal Weather Corrected)	75.19	75.53	75.62	75.89	76.23	76.20	76.41	76.82	77.25	77.55	
	Net Load (Extreme Weather Corrected)	80.06	80.42	80.51	80.80	81.16	81.13	81.35	81.79	82.25	82.57	
Port Arthur TS #1	Synergy North + H1 Dx (Gross Forecast)	39.14	39.51	39.78	40.23	40.68	40.88	41.22	41.68	42.16	42.54	55.26
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.01	0.01	0.05	0.12	0.18	0.23	0.26	0.26	0.26	0.27	
	Net Load (Normal Weather Corrected)	39.13	39.50	39.73	40.10	40.50	40.65	40.97	41.42	41.90	42.28	
	Net Load (Extreme Weather Corrected)	41.66	42.06	42.30	42.70	43.12	43.28	43.62	44.10	44.61	45.01	
Murillo DS	Hydro One Distribution (Gross Forecast)	20.09	20.27	20.46	20.67	20.81	20.93	21.07	21.21	21.35	21.47	11.70
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.01	0.02	0.06	0.09	0.12	0.13	0.13	0.13	0.13	
	Net Load (Normal Weather Corrected)	20.09	20.26	20.44	20.61	20.72	20.81	20.93	21.08	21.22	21.33	
	Net Load (Extreme Weather Corrected)	21.39	21.57	21.76	21.94	22.06	22.16	22.29	22.44	22.59	22.72	
Nipigon DS	Hydro One Distribution (Gross Forecast)	3.89	3.92	3.96	4.01	4.04	4.07	4.11	4.15	4.19	4.22	10.44
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.02	0.02	0.03	0.03	0.03	0.03	
	Net Load (Normal Weather Corrected)	3.89	3.92	3.96	4.00	4.02	4.05	4.08	4.12	4.16	4.20	
	Net Load (Extreme Weather Corrected)	4.14	4.18	4.22	4.25	4.28	4.31	4.35	4.39	4.43	4.47	
Red Rock DS	Hydro One Distribution (Gross Forecast)	4.46	4.46	4.47	4.49	4.49	4.49	4.49	4.50	4.50	4.50	8.64

Transformer Station		**Near Term Forecast (MW)**					**Medium Term Forecast (MW)**					**Winter 10-Day LTR for TS / Planned Loading Limit for DS* (MW)**
		2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.01	0.02	0.03	0.03	0.03	0.03	0.03	
	Net Load (Normal Weather Corrected)	4.46	4.46	4.47	4.47	4.47	4.46	4.46	4.47	4.47	4.48	
	Net Load (Extreme Weather Corrected)	4.75	4.75	4.76	4.76	4.76	4.75	4.75	4.76	4.76	4.77	

Appendix B: Northwest Ontario Region Non-Coincident Summer Load Forecast

* LTR/PLL based on 0.9 power factor

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Greenstone-Marathon Sub-Region												
Longlac TS	Hydro One Distribution (Gross Forecast)	10.40	11.93	12.50	15.46	15.56	15.66	15.76	11.68	11.80	11.91	42.84
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.07	0.08	0.10	0.17	0.19	0.23	0.26	0.22	0.24	0.26	
	Net Load (Normal Weather Corrected)	10.33	11.85	12.40	15.29	15.36	15.43	15.50	11.46	11.55	11.64	
	Net Load (Extreme Weather Corrected)	10.96	12.57	13.15	16.22	16.30	16.36	16.44	12.15	12.25	12.35	
Manitouwadge TS	Hydro One Distribution (Gross Forecast)	5.44	5.50	5.58	5.66	6.49	6.55	6.60	6.67	6.73	6.79	37.53
	DG (Incremental)	8.00	8.00	8.00	8.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.03	0.04	0.04	0.06	0.08	0.10	0.11	0.13	0.14	0.15	
	Net Load (Normal Weather Corrected)	-2.60	-2.54	-2.47	-2.41	6.41	6.44	6.49	6.53	6.58	6.63	
	Net Load (Extreme Weather Corrected)	-2.76	-2.70	-2.62	-2.56	6.80	6.84	6.88	6.93	6.98	7.03	
Beardmore DS #2	Hydro One Distribution (Gross Forecast)	0.65	0.66	0.67	0.67	0.68	0.69	0.69	0.70	0.71	0.71	8.46
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	
	Net Load (Normal Weather Corrected)	0.65	0.65	0.66	0.67	0.67	0.68	0.68	0.69	0.69	0.70	
	Net Load (Extreme Weather Corrected)	0.69	0.69	0.70	0.71	0.71	0.72	0.72	0.73	0.74	0.74	
Jellicoe DS #3	Hydro One Distribution (Gross Forecast)	0.30	0.30	0.30	0.31	0.31	0.31	0.31	0.32	0.32	0.32	1.71
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	Net Load (Normal Weather Corrected)	0.30	0.30	0.30	0.30	0.31	0.31	0.31	0.31	0.31	0.31	
	Net Load (Extreme Weather Corrected)	0.31	0.32	0.32	0.32	0.32	0.33	0.33	0.33	0.33	0.33	
Manitouwadge DS #1	Hydro One Distribution (Gross Forecast)	0.76	0.77	0.78	0.79	0.00	0.00	0.00	0.00	0.00	0.00	6.75
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	
	Net Load (Normal Weather Corrected)	0.76	0.76	0.77	0.78	0.00	0.00	0.00	0.00	0.00	0.00	
	Net Load (Extreme Weather Corrected)	0.80	0.81	0.82	0.82	0.00	0.00	0.00	0.00	0.00	0.00	
Marathon DS	Hydro One Distribution (Gross Forecast)	4.38	4.45	4.51	4.59	4.64	4.68	4.73	4.79	4.85	4.90	7.74
	DG (Incremental)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	
	CDM (Incremental)	0.03	0.03	0.04	0.05	0.06	0.07	0.08	0.09	0.10	0.11	
	Net Load (Normal Weather Corrected)	4.33	4.39	4.45	4.51	4.55	4.59	4.63	4.68	4.72	4.77	
	Net Load (Extreme Weather Corrected)	4.60	4.66	4.72	4.79	4.83	4.87	4.91	4.96	5.01	5.06	
Pic DS	Hydro One Distribution (Gross Forecast)	5.89	5.96	6.05	6.14	6.19	6.25	6.31	6.37	6.44	6.50	8.46
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.04	0.04	0.05	0.07	0.08	0.09	0.10	0.12	0.13	0.14	
	Net Load (Normal Weather Corrected)	5.85	5.92	6.00	6.07	6.12	6.16	6.20	6.25	6.31	6.36	
	Net Load (Extreme Weather Corrected)	6.21	6.28	6.36	6.44	6.49	6.53	6.58	6.63	6.69	6.75	
Schreiber Winnipeg DS	Hydro One Distribution (Gross Forecast)	2.27	2.30	2.33	2.37	2.38	2.40	2.42	2.45	2.47	2.49	6.75
	DG (Incremental)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
	CDM (Incremental)	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.05	
	Net Load (Normal Weather Corrected)	2.25	2.27	2.30	2.33	2.34	2.35	2.37	2.39	2.41	2.42	
	Net Load (Extreme Weather Corrected)	2.38	2.41	2.44	2.47	2.48	2.50	2.52	2.53	2.55	2.57	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
White River DS	Hydro One Distribution (Gross Forecast)	7.44	7.53	7.63	7.74	7.81	7.87	7.93	8.01	8.08	8.15	11.25
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.05	0.05	0.06	0.08	0.10	0.12	0.13	0.15	0.17	0.18	
	Net Load (Normal Weather Corrected)	7.39	7.48	7.57	7.66	7.71	7.75	7.80	7.86	7.91	7.97	
	Net Load (Extreme Weather Corrected)	7.84	7.94	8.03	8.12	8.18	8.22	8.28	8.33	8.40	8.45	
North of Dryden Sub-Region												
Red Lake TS	Hydro One Distribution (Gross Forecast)	19.12	19.39	19.69	19.99	20.24	20.48	20.74	21.00	21.27	21.53	50.67
	DG (Incremental)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
	CDM (Incremental)	0.12	0.13	0.16	0.21	0.25	0.30	0.34	0.40	0.44	0.47	
	Net Load (Normal Weather Corrected)	19.00	19.26	19.52	19.77	19.98	20.18	20.39	20.60	20.83	21.06	
	Net Load (Extreme Weather Corrected)	20.16	20.43	20.71	20.97	21.19	21.40	21.63	21.85	22.10	22.34	
Cat Lake MTS	Hydro One Distribution (Gross Forecast)	1.05	1.06	1.07	1.08	1.09	1.10	1.11	1.12	1.13	1.14	2.70
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	
	Net Load (Normal Weather Corrected)	1.04	1.05	1.06	1.07	1.08	1.08	1.09	1.10	1.11	1.11	
	Net Load (Extreme Weather Corrected)	1.10	1.12	1.13	1.14	1.14	1.15	1.16	1.17	1.17	1.18	
Crow River DS	Hydro One Distribution (Gross Forecast)	1.61	1.63	1.65	1.67	1.68	1.70	1.71	1.72	1.74	1.75	7.74
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.04	0.04	
	Net Load (Normal Weather Corrected)	1.60	1.62	1.64	1.65	1.66	1.67	1.68	1.69	1.70	1.71	
	Net Load (Extreme Weather Corrected)	1.70	1.72	1.73	1.75	1.76	1.77	1.78	1.79	1.81	1.82	
Perrault Falls DS	Hydro One Distribution (Gross Forecast)	0.73	0.74	0.75	0.76	0.77	0.78	0.79	0.79	0.80	0.81	7.74

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	
	Net Load (Normal Weather Corrected)	0.73	0.74	0.75	0.76	0.76	0.77	0.77	0.78	0.79	0.79	
	Net Load (Extreme Weather Corrected)	0.77	0.78	0.79	0.80	0.81	0.81	0.82	0.83	0.83	0.84	
Slate Falls DS	Hydro One Distribution (Gross Forecast)	0.39	0.40	0.40	0.41	0.41	0.41	0.42	0.42	0.42	0.43	3.15
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	
	Net Load (Normal Weather Corrected)	0.39	0.39	0.40	0.40	0.40	0.41	0.41	0.41	0.41	0.42	
	Net Load (Extreme Weather Corrected)	0.41	0.42	0.42	0.43	0.43	0.43	0.43	0.44	0.44	0.44	
Ear Falls DS	Hydro One Distribution (Gross Forecast)	4.84	4.89	4.95	5.01	5.04	5.07	5.10	5.14	5.18	5.22	7.74
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.03	0.03	0.04	0.05	0.06	0.07	0.08	0.10	0.11	0.11	
	Net Load (Normal Weather Corrected)	4.81	4.86	4.91	4.95	4.97	4.99	5.02	5.04	5.07	5.10	
	Net Load (Extreme Weather Corrected)	5.11	5.15	5.20	5.25	5.28	5.30	5.32	5.35	5.38	5.41	
West of Thunder Bay Sub-Region												
Barwick TS	Hydro One Distribution (Gross Forecast)	11.53	11.67	11.84	12.01	12.12	12.23	12.35	12.47	12.60	12.72	56.70
	DG (Incremental)	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	3.56	
	CDM (Incremental)	0.07	0.08	0.09	0.13	0.15	0.18	0.20	0.24	0.26	0.28	
	Net Load (Normal Weather Corrected)	7.89	8.04	8.18	8.33	8.41	8.49	8.58	8.68	8.78	8.88	
	Net Load (Extreme Weather Corrected)	8.37	8.52	8.68	8.83	8.92	9.01	9.11	9.21	9.32	9.42	
Dryden TS	Hydro One Distribution (Gross Forecast)	12.84	13.05	13.29	13.55	13.73	13.90	14.09	14.30	14.50	14.69	54.18
	DG (Incremental)	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	1.43	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	CDM (Incremental)	0.08	0.09	0.11	0.15	0.17	0.20	0.23	0.27	0.30	0.32	
	Net Load (Normal Weather Corrected)	11.33	11.54	11.76	11.97	12.12	12.27	12.43	12.60	12.77	12.94	
	Net Load (Extreme Weather Corrected)	12.02	12.24	12.47	12.70	12.86	13.02	13.19	13.36	13.55	13.73	
Fort Frances MTS	FFPC (Gross Forecast)	12.25	12.31	12.11	12.17	12.26	12.32	12.31	12.37	12.40	12.46	23.94
	DG (Incremental)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	
	CDM (Incremental)	0.08	0.08	0.10	0.13	0.15	0.18	0.20	0.23	0.25	0.27	
	Net Load (Normal Weather Corrected)	12.12	12.18	11.96	11.99	12.05	12.09	12.06	12.09	12.09	12.13	
	Net Load (Extreme Weather Corrected)	12.86	12.92	12.69	12.72	12.79	12.82	12.79	12.82	12.83	12.87	
Moose Lake TS	Atikokan Hydro (Gross Forecast)	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	9.63
	DG (Incremental)	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	
	CDM (Incremental)	0.04	0.04	0.05	0.06	0.08	0.09	0.10	0.11	0.12	0.13	
	Net Load (Normal Weather Corrected)	5.95	5.94	5.94	5.92	5.91	5.90	5.89	5.87	5.86	5.85	
	Net Load (Extreme Weather Corrected)	6.31	6.31	6.30	6.28	6.27	6.25	6.24	6.23	6.22	6.21	
Kenora MTS	Synergy North (Gross Forecast)	17.24	17.54	17.78	17.90	18.20	18.61	18.61	18.91	19.24	19.57	21.69
	DG (Incremental)	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	
	CDM (Incremental)	0.11	0.12	0.14	0.19	0.23	0.27	0.31	0.36	0.40	0.43	
	Net Load (Normal Weather Corrected)	17.05	17.34	17.55	17.63	17.89	18.25	18.22	18.47	18.76	19.06	
	Net Load (Extreme Weather Corrected)	18.09	18.40	18.62	18.70	18.97	19.36	19.33	19.59	19.90	20.22	
Agimak DS	Hydro One Distribution (Gross Forecast)	2.48	2.51	2.54	2.57	2.59	2.61	2.64	2.66	2.69	2.71	8.46
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.06	0.06	
	Net Load (Normal Weather Corrected)	2.46	2.49	2.52	2.54	2.56	2.57	2.59	2.61	2.63	2.65	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	Net Load (Extreme Weather Corrected)	2.61	2.64	2.67	2.70	2.71	2.73	2.75	2.77	2.79	2.81	
Burleigh DS	Hydro One Distribution (Gross Forecast)	2.40	2.42	2.45	2.48	2.49	2.50	2.52	2.54	2.56	2.57	7.74
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06	
	Net Load (Normal Weather Corrected)	2.38	2.40	2.42	2.45	2.46	2.47	2.48	2.49	2.50	2.52	
	Net Load (Extreme Weather Corrected)	2.52	2.55	2.57	2.59	2.61	2.62	2.63	2.64	2.65	2.67	
Clearwater Bay DS	Hydro One Distribution (Gross Forecast)	4.25	4.29	4.33	4.37	4.40	4.42	4.44	4.47	4.49	4.52	6.93
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.03	0.03	0.03	0.05	0.06	0.07	0.07	0.08	0.09	0.10	
	Net Load (Normal Weather Corrected)	4.23	4.26	4.29	4.33	4.34	4.35	4.37	4.38	4.40	4.42	
	Net Load (Extreme Weather Corrected)	4.48	4.52	4.55	4.59	4.60	4.62	4.63	4.65	4.67	4.69	
Eton DS	Hydro One Distribution (Gross Forecast)	1.73	1.74	1.76	1.79	1.80	1.81	1.83	1.84	1.86	1.87	8.46
	DG (Incremental)	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	
	CDM (Incremental)	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.04	0.04	
	Net Load (Normal Weather Corrected)	1.69	1.71	1.72	1.74	1.75	1.76	1.77	1.78	1.79	1.81	
	Net Load (Extreme Weather Corrected)	1.79	1.81	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.92	
Keewatin DS	Hydro One Distribution (Gross Forecast)	3.86	3.90	3.95	4.00	4.03	4.05	4.08	4.12	4.15	4.18	7.74
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.02	0.03	0.03	0.04	0.05	0.06	0.07	0.08	0.09	0.09	
	Net Load (Normal Weather Corrected)	3.84	3.88	3.92	3.96	3.98	3.99	4.02	4.04	4.06	4.09	
	Net Load (Extreme Weather Corrected)	4.07	4.11	4.16	4.20	4.22	4.24	4.26	4.28	4.31	4.34	
Margach DS	Hydro One Distribution (Gross Forecast)	6.40	6.46	6.53	6.61	6.65	6.68	6.73	6.77	6.82	6.86	7.74

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.04	0.04	0.05	0.07	0.08	0.10	0.11	0.13	0.14	0.15	
	Net Load (Normal Weather Corrected)	6.36	6.42	6.48	6.54	6.56	6.58	6.61	6.65	6.68	6.71	
	Net Load (Extreme Weather Corrected)	6.75	6.81	6.87	6.93	6.96	6.99	7.02	7.05	7.09	7.12	
Minaki DS	Hydro One Distribution (Gross Forecast)	1.02	1.04	1.07	1.09	1.11	1.13	1.15	1.17	1.19	1.21	8.46
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	
	Net Load (Normal Weather Corrected)	1.02	1.04	1.06	1.08	1.10	1.11	1.13	1.15	1.17	1.19	
	Net Load (Extreme Weather Corrected)	1.08	1.10	1.12	1.15	1.16	1.18	1.20	1.22	1.24	1.26	
Nestor Falls DS	Hydro One Distribution (Gross Forecast)	1.96	1.98	2.00	2.02	2.03	2.04	2.05	2.07	2.08	2.09	7.74
	DG (Incremental)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
	CDM (Incremental)	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.05	
	Net Load (Normal Weather Corrected)	1.94	1.96	1.98	1.99	2.00	2.01	2.01	2.02	2.03	2.04	
	Net Load (Extreme Weather Corrected)	2.06	2.08	2.10	2.12	2.12	2.13	2.14	2.15	2.16	2.17	
Sam Lake DS	Hydro One Distribution (Gross Forecast)	11.34	11.47	11.63	11.79	11.89	11.99	12.09	12.21	12.33	12.44	16.92
	DG (Incremental)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
	CDM (Incremental)	0.07	0.08	0.09	0.13	0.15	0.18	0.20	0.23	0.25	0.27	
	Net Load (Normal Weather Corrected)	11.26	11.39	11.52	11.66	11.73	11.80	11.88	11.97	12.06	12.15	
	Net Load (Extreme Weather Corrected)	11.95	12.08	12.22	12.36	12.45	12.52	12.61	12.70	12.80	12.89	
Sapawe DS	Hydro One Distribution (Gross Forecast)	3.08	3.12	3.15	3.20	3.22	3.24	3.27	3.30	3.33	3.35	3.42
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.02	0.02	0.03	0.03	0.04	0.05	0.05	0.06	0.07	0.07	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	Net Load (Normal Weather Corrected)	3.06	3.09	3.13	3.16	3.18	3.20	3.22	3.24	3.26	3.28	
	Net Load (Extreme Weather Corrected)	3.25	3.28	3.32	3.35	3.37	3.39	3.41	3.43	3.46	3.48	
Shabaqua DS	Hydro One Distribution (Gross Forecast)	3.50	3.52	3.56	3.60	3.62	3.64	3.66	3.68	3.71	3.73	6.75
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.02	0.02	0.03	0.04	0.05	0.05	0.06	0.07	0.08	0.08	
	Net Load (Normal Weather Corrected)	3.47	3.50	3.53	3.55	3.57	3.58	3.59	3.61	3.63	3.64	
	Net Load (Extreme Weather Corrected)	3.68	3.71	3.74	3.77	3.78	3.80	3.81	3.83	3.85	3.87	
Sioux Narrows DS	Hydro One Distribution (Gross Forecast)	2.29	2.31	2.34	2.36	2.38	2.39	2.41	2.42	2.44	2.46	8.46
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.05	
	Net Load (Normal Weather Corrected)	2.27	2.29	2.31	2.33	2.34	2.35	2.36	2.37	2.39	2.40	
	Net Load (Extreme Weather Corrected)	2.41	2.43	2.45	2.47	2.48	2.49	2.50	2.52	2.53	2.54	
Valora DS	Hydro One Distribution (Gross Forecast)	0.47	0.48	0.49	0.50	0.51	0.52	0.52	0.53	0.54	0.55	3.42
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
	Net Load (Normal Weather Corrected)	0.47	0.48	0.49	0.50	0.50	0.51	0.51	0.52	0.53	0.53	
	Net Load (Extreme Weather Corrected)	0.50	0.51	0.52	0.53	0.53	0.54	0.55	0.55	0.56	0.57	
Vermilion Bay DS	Hydro One Distribution (Gross Forecast)	2.20	2.23	2.27	2.30	2.33	2.35	2.38	2.41	2.44	2.46	6.75
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.05	0.05	0.05	
	Net Load (Normal Weather Corrected)	2.19	2.22	2.25	2.28	2.30	2.32	2.34	2.36	2.39	2.41	
	Net Load (Extreme Weather Corrected)	2.32	2.35	2.39	2.42	2.44	2.46	2.48	2.51	2.53	2.56	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
Crilly DS	Hydro One Distribution (Gross Forecast)	0.92	0.93	0.95	0.96	0.97	0.98	0.99	0.99	1.00	1.01	1.71
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	
	Net Load (Normal Weather Corrected)	0.92	0.93	0.94	0.95	0.96	0.96	0.97	0.98	0.98	0.99	
	Net Load (Extreme Weather Corrected)	0.97	0.98	1.00	1.01	1.01	1.02	1.03	1.04	1.04	1.05	
Kenora DS	Hydro One Distribution (Gross Forecast)	3.59	3.64	3.69	3.74	3.78	3.81	3.85	3.89	3.93	3.96	8.46
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.02	0.02	0.03	0.04	0.05	0.06	0.06	0.07	0.08	0.09	
	Net Load (Normal Weather Corrected)	3.57	3.61	3.66	3.70	3.73	3.75	3.78	3.81	3.84	3.88	
	Net Load (Extreme Weather Corrected)	3.79	3.83	3.88	3.93	3.96	3.98	4.01	4.04	4.08	4.11	
Whitedog DS	Hydro One Distribution (Gross Forecast)	1.03	1.05	1.06	1.08	1.09	1.10	1.11	1.13	1.14	1.15	2.25
	DG (Incremental)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
	CDM (Incremental)	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	
	Net Load (Normal Weather Corrected)	1.03	1.04	1.05	1.07	1.08	1.09	1.10	1.11	1.12	1.13	
	Net Load (Extreme Weather Corrected)	1.09	1.10	1.12	1.13	1.14	1.15	1.16	1.17	1.18	1.19	
Thunder Bay Sub-Region												
Birch TS	Synergy North (Gross Forecast)	68.59	68.85	69.18	69.22	69.92	70.74	71.28	71.69	72.26	72.62	91.98
	DG (Incremental)	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	
	CDM (Incremental)	0.43	0.45	0.55	0.74	0.88	1.04	1.18	1.36	1.48	1.59	
	Net Load (Normal Weather Corrected)	68.01	68.25	68.48	68.33	68.90	69.55	69.96	70.19	70.63	70.88	
	Net Load (Extreme Weather Corrected)	72.15	72.41	72.65	72.49	73.09	73.79	74.22	74.46	74.93	75.19	
Fort Williams TS	Synergy North (Gross Forecast)	70.56	70.92	71.34	71.48	72.28	73.17	73.82	74.36	75.05	75.54	90.36

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	
	DG (Incremental)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	
	CDM (Incremental)	0.44	0.47	0.57	0.77	0.91	1.08	1.22	1.41	1.54	1.66	
	Net Load (Normal Weather Corrected)	70.07	70.41	70.72	70.67	71.32	72.04	72.55	72.90	73.46	73.83	
	Net Load (Extreme Weather Corrected)	74.33	74.69	75.02	74.97	75.66	76.43	76.97	77.33	77.93	78.33	
Port Arthur TS #1	Synergy North + H1 Dx (Gross Forecast)	33.89	34.25	34.57	34.92	35.23	35.53	35.88	36.21	36.57	36.89	46.80
	DG (Incremental)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	
	CDM (Incremental)	0.21	0.23	0.28	0.37	0.44	0.52	0.59	0.69	0.75	0.81	
	Net Load (Normal Weather Corrected)	33.63	33.97	34.25	34.50	34.74	34.96	35.24	35.48	35.77	36.04	
	Net Load (Extreme Weather Corrected)	35.67	36.04	36.33	36.59	36.85	37.08	37.38	37.64	37.95	38.23	
Murillo DS	Hydro One Distribution (Gross Forecast)	9.82	9.92	10.04	10.16	10.22	10.28	10.35	10.42	10.48	10.54	8.73
	DG (Incremental)	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	
	CDM (Incremental)	0.06	0.07	0.08	0.11	0.13	0.15	0.17	0.20	0.22	0.23	
	Net Load (Normal Weather Corrected)	9.63	9.73	9.83	9.92	9.97	10.00	10.05	10.09	10.14	10.18	
	Net Load (Extreme Weather Corrected)	10.22	10.32	10.43	10.53	10.58	10.61	10.66	10.71	10.76	10.80	
Nipigon DS	Hydro One Distribution (Gross Forecast)	2.46	2.49	2.52	2.56	2.58	2.60	2.63	2.65	2.68	2.71	7.74
	DG (Incremental)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	
	CDM (Incremental)	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.06	0.06	
	Net Load (Normal Weather Corrected)	2.44	2.47	2.49	2.52	2.54	2.56	2.58	2.60	2.62	2.64	
	Net Load (Extreme Weather Corrected)	2.59	2.62	2.65	2.68	2.69	2.71	2.73	2.75	2.78	2.80	
Red Rock DS	Hydro One Distribution (Gross Forecast)	3.13	3.13	3.14	3.15	3.16	3.16	3.16	3.16	3.16	3.16	6.75
	DG (Incremental)	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	
	CDM (Incremental)	0.02	0.02	0.03	0.03	0.04	0.05	0.05	0.06	0.06	0.07	

Transformer Station		Near Term Forecast (MW)					Medium Term Forecast (MW)					Summer 10-Day LTR for TS / Planned Loading Limit for DS* (MW)
		2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	
	Net Load (Normal Weather Corrected)	2.97	2.97	2.98	2.98	2.97	2.97	2.96	2.96	2.96	2.95	
	Net Load (Extreme Weather Corrected)	3.15	3.15	3.16	3.16	3.16	3.15	3.14	3.14	3.14	3.13	

Appendix C: Winter 2029 Load Forecast & Dependable Hydro Generation Breakdown by Sub-Region

Sub-Region	Load (MW)	Dependable Generation @ 98% (MW)	Dependable Generation @ 85% (MW)
Thunder Bay Sub-Region	454	115	188
West of Thunder Bay Sub-Region	244	24	46
North of Dryden Sub-Region (Including First Nation Communities)	130	46	59
Greenstone-Marathon Sub-Region	145	6	26
Total	**973**	**191**	**318**

Appendix D: Lists of Step-Down Transformer Stations

Sub-Region	Station	Voltage (kV)	Supply Circuits
North of Dryden	Ear Falls TS	115/44	M3E, E4D, E1C, E2R
	Red Lake TS	115/44	E2R
	Cat Lake MTS	115/25	E1C
	Crow River DS	115/25	C2M
	Perrault Falls DS	115/12.5	E4D
	Slate Falls DS	115/24.9	E1C
Greenstone-Marathon	Longlac TS	115/44	A4L
	Manitouwadge TS	115/44	M2W
	Marathon TS	230/115	T1M, W21M, M23L, M2W, M24L, W22M
	Beardmore DS #2	115/25	A4L
	Jellicoe DS #3	115/12.5	A4L
	Manitouwadge DS #1	115/12.5	M2W
	Marathon DS	115/25	T1M
	Pic DS	115/25	M2W
	Schreiber Winnipeg DS	115/12.5	A5A
	White River DS	115/25	M2W
West of Thunder Bay	Barwick TS	115/44	K6F
	Dryden TS	230/115	K3D, D26A, E4D, D5D, K23D, M2D
	Fort Frances TS	232/115	K24F, F25A, K6F, F1B, F2B, F3M
	Kenora TS	230/115	K24F, K7K, K21W, K23D, K22W
	Mackenzie TS	230/115	D26A, A22L, A3M, F25A, A21L, N93A
	Moose Lake TS	115/44	A3M, M1S, M2D, B6M
	Fort Frances MTS	115/12.47	F1B
	Kenora MTS	115/12.5	15M1
	Agimak DS	115/25	29M1
	Burleigh DS	115/12.5	F1B

Sub-Region	Station	Voltage (kV)	Supply Circuits
	Clearwater Bay DS	115/25	SK1
	Eton DS	115/12.48	K3D
	Keewatin DS	115/12.5	SK1
	Margach DS	115/25	K6F
	Minaki DS	115/25	K4W
	Nestor Falls DS	115/13.2	K6F
	Sam Lake DS	115/26.4	K3D
	Sapawe DS	115/12.5	B6M
	Shabaqua DS	115/12.5	B6M
	Sioux Narrows DS	115/12.5	K6F
	Valora DS	115/25	29M1
	Vermilion Bay DS	115/12.5	K3D
Thunder Bay	Birch TS	115/28.4	Q9B, P7B, Q8B, Q5B, R2LB, P3B, Q4B, R1LB, B6M
	Fort William TS	115/25	Q5B, Q4B
	Lakehead TS	230/115	A22L, M23L, A21L, R2LB, L4P, M24L, A7L, R1LB, A8L, L3P
	Port Arthur TS #1	115/25	P7B, P1T, A6P, L4P, P3B, P5M, L3P
	Murillo DS	115/26.40	B6M
	Nipigon DS	115/4.16	57M1
	Red Rock DS	115/12.5	56M1

Appendix E: Lists of Transmission Circuits

Circuit(s)	Location	Voltage (kV)
D26A	Mackenzie x Dryden	230
F25A	Mackenzie x Fort Frances	230
K23D	Dryden x TCPL Vermill Bay x Kenora	230
K24F	Fort Frances x Kenora	230
N93A	Mackenzie x Marmion Lake x Atikokan	230
K21W, K22W	Kenora x Whiteshell (Manitoba Hydro)	230
A21L, A22L	Mackenzie x Lakehead	230
M23L, M24L	Marathon x Lakehead	230
15M1	Kenora x Rabbit Lake	115
29M1	Ignace x Camp Lake x Valora x Mattabi	115
A3M	Mackenzie x Moose Lake	115
B6M	Moose Lake x Sapawe x Shabaqua x Stanley x Murillo x Birch	115
D5D	Dryden x Domtar Dryden	115
F1B	Fort Frances x Burleigh	115
F3M	Fort Frances x Internat Fls (Minnesota Power)	115
K2M	Kenora x Norman	115
K3D	Dryden x Sam Lake x Eton x Vermilion Bay x Rabbit Lake	115
K4W	White Dog x Minaki x Rabbit Lake	115
K6F	Fort Frances x Ainsworth x Nestor Falls x Sioux Narrows x Rabbit Lake	115
K7K	Kenora x Weyerhaeuser Ken x Rabbit Lake	115
M1S	Moose Lake x Valerie Falls x Mill Creek	115
M2D	Moose Lake x Ignace x Dryden	115
SK1	Rabbit Lake x Keewatin x Forgie	115
W3C	White Dog x Caribou Falls	115
56M1	Nipignon x Red Rock	115
57M1	Reserve x Nipignon	115
A6P	Alexander x Port Arthur	115
L3P, L4P	Lakehead x Port Arthur	115
P3B, P7B	Port Arthur x Birch	115
P5M	Port Arthur x Conmee	115
Q4B, Q5B, Q8B, Q9B	Thunder Bay x Birch	115
R1LB, R2LB	Lakehead x Pine Portage x Birch	115
S1C	Silver Falls x Lac Des Iles x Conmee	115
A1B	Aguasabon x Terrace Bay	115
A4L	Alexander x Nipignon x Beardmore x Jellicoe x Roxmark x Longlac	115
A5A	Alexander x Minnova x Schreiber x Aguasabon	115

Circuit(s)	Location	Voltage (kV)
C1A, C2A, C3A	Alexander x Cameron Falls	115
GA1	Upper White River x Lower White River	115
M2W	Marathon x Black River x Umbata Falls x Hemlo Mine x White River	115
R9A	Alexander x Pine Portage	115
E1C	Ear Falls x Selco x Slate Falls x Cat Lake x Pickle Lake	115
C2M	Pickle Lake x Crow River x Musselwhite	115
E2R	Ear Falls x Balmer x Red Lake	115
E4D	Ear Falls x Scout Lake x Dryden	115
M3E	Manitou Falls x Ear Falls	115
T1M	Terrace Bay x Marathon	115

Appendix F: Lists of LDCs in the Northwest Ontario Region

Company	Connection Type
Atikokan Hydro Inc.	Transmission
Fort Frances Power Corporation	Transmission
Hydro One Networks Inc. (Distribution)	Transmission
Sioux Lookout Hydro Inc.	Distribution
Synergy North	Transmission

Appendix G: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
EOL	End-Of-Life
FFPC	Fort Frances Power Corporation
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
Jct	Junction
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator

Acronym	Description
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Appendix I

Scoping Assessment Outcome Report issued by IESO on January 13, 2021

Northwest Scoping Assessment Outcome Report

January 13, 2021

Connecting Today.
Powering Tomorrow.

Table of Contents

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB or Board) regional planning process and sets out the planning approach to address electricity needs that have been identified in the Northwest. The OEB started regional planning in 2011 and endorsed the Planning Process Working Group's Report to the Board in May 2013. The Board formalized the process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

In the Northwest, the first cycle of the regional planning divided the region into four sub-regions each with their own Integrated Regional Resource Plan (IRRP) published between Jan 2015 and Dec 2016. These sub-regions include Greenstone-Marathon, North of Dryden, Thunder Bay and West of Thunder Bay. The first cycle concluded in June 2017 with the publication of the Regional Infrastructure Plan (RIP).

The current cycle of regional planning for the Northwest started in March 2020. The Needs Assessment (NA) is the first step in the regional planning process and was carried out by the Study Team led by Hydro One Networks Inc. (Hydro One). This report was finalized on July 17, 2020 and flagged a number of needs requiring further regional coordination as well as a few needs to be addressed by local planning. This information was an input to this Scoping Assessment Outcome Report.

As part of the Scoping Assessment, the Study Team reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach to address them. The assessment determined the best geographic grouping of the needs to efficiently carry out the study. It also considered past and ongoing initiatives in the region.

This Scoping Assessment Outcome Report recommends a single IRRP for the Northwest region focused on several specific needs that have been identified or raised by stakeholders through ongoing outreach and previous planning cycles.

This Scoping Assessment report is structured as follows:

- Section 2 lists the study team.
- Section 3 provides an overview of the region, the previous regional planning cycle, and major transmission reinforcements since the previous cycle.
- Section 4 summarizes the new and update needs as described in the Needs Assessment.
- Section 5 describes the criteria used to select a regional planning approach and specifies the scope of the IRRP.

Appendix 1 defines the acronyms used in this document and Appendix 2 establishes the draft Terms of Reference for the IRRP and the composition of the IRRP Technical Working Group.

2. Study Team

The Scoping Assessment was carried out with the following participants:

Independent Electricity System Operator (IESO)

Hydro One Networks Inc. (Hydro One Transmission)

Hydro One Networks Inc. (Hydro One Distribution)

Atikokan Hydro Inc.

Fort Frances Power Corporation

Sioux Lookout Hydro Inc.

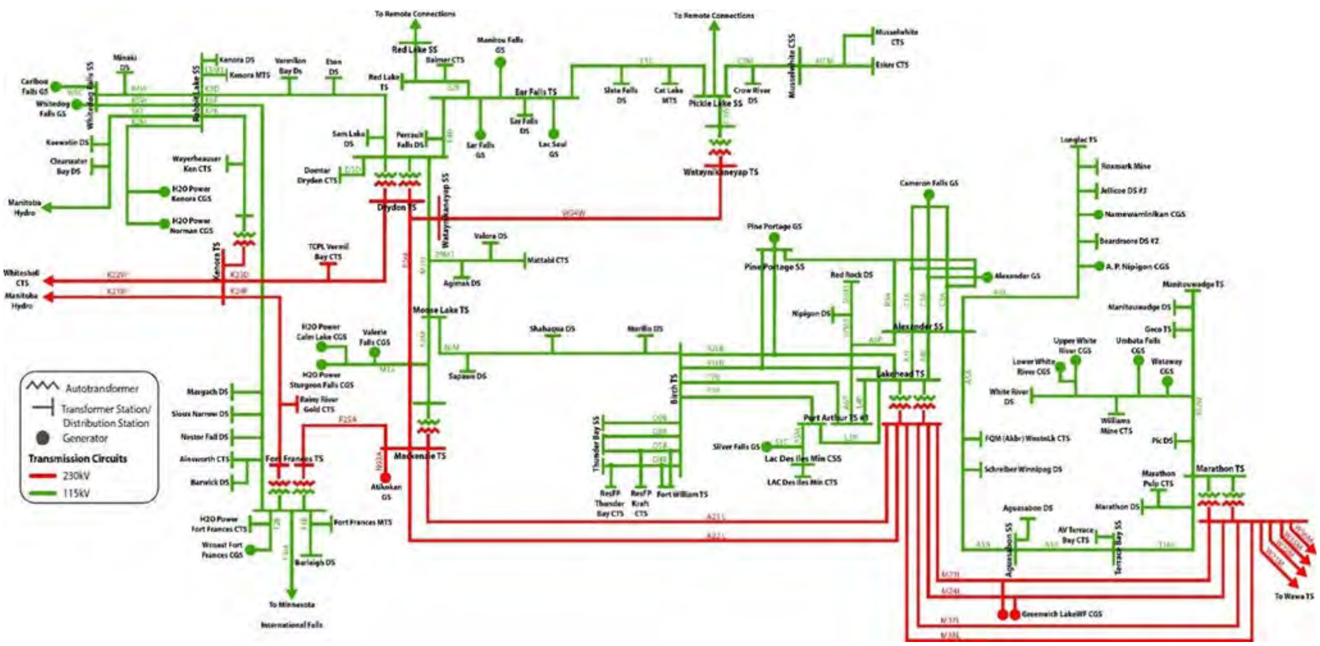
Synergy North

3. Overview of Region and Background

The Northwest region includes the area roughly bounded by Lake Superior to the south, the Marathon area to the east, and the Manitoba border to the west. It includes the districts of Kenora, Rainy River and Thunder Bay.

Note that, for regional electricity planning purposes, the region is defined by electrical infrastructure rather than geography. The region encompasses the 230 kV circuits from the Manitoba interties in the west to Marathon TS in the east as well as the 115 kV sub-systems in between. The single line diagram of the electrical infrastructure in the region is shown in Figure 3-1.

Figure 3-1 | Electricity Infrastructure in the Northwest Ontario Region



The Northwest region encompasses a vast geographic area and a diversity of economic and social factors unique within Ontario. Planning in this region possesses uncertainties and challenges not normally seen in other parts of the province. Demand in this region is largely driven by resource based industrial customers such as mines and forestry operations. Their development is highly dependent on factors such as commodity prices and access to financing.

In addition to the cities and towns, the Northwest has many rural and remote communities often served from long single-supply transmission circuits. The municipalities within the Northwest region includes the Town of Marathon, Municipality of Greenstone, Township of Nipigon, Township of Manitowadge, Township of Schreiber, Township of Terrace Bay, Township of White River, City of Thunder Bay, Township of Red Rock, Township of Nipigon, Municipality of Neebing, Municipality of Oliver Paipoonge, Municipality of Shuniah, Township of O'Connor, Township of Conmee, Township of Dorion, Township of Gillies, Township of Alberton, Town of Atikokan, Township of Chapple, Township of Dawson, Township of Emo, Town of Fort Frances, Township of Lake of the Woods, Township of La Vallee, Township of Morley, Town of Rainy River, City of Dryden, City of Kenora, Municipality of Machin, Municipality of Sioux Lookout, Township of Ignace, and Township of Sioux Narrows-Nestor Falls.

The Northwest Ontario region is home to about half of the First Nation communities in the province as shown in Table 3-1. A number of Métis communities are also located in the Northwest region. The following are affiliated with the Métis Nation of Ontario: Atikokan and Area Metis Council, Greenstone Métis Council, Kenora Metis Council, Superior North Shore Métis Council, Northwest Métis Council, Sunset Country Metis Council and Thunder Bay Métis Council. Red Sky Métis Independent Nation is another Métis community with its office located in Thunder Bay. Note that not all First Nation and Métis communities listed are grid connected.

Table 3-1 | List of First Nation Communities in the Northwest Region

First Nation Communities	
Animbiigoo Zaagi'igan Anishinaabek	Naicatchewenin
Animakee Wa Zhing #37	Namaygoosisagagun
Anishinaabeg of Naongashing	Naotkamegwanning
Anishnawbe of Wauzhushk Onigum	Neskantaga
Aroland	Nigigoonsiminikaaning Nation
Bearskin Lake	Niisachewan
Big Grassy	North Caribou Lake
Biinjitiwaabik Zaaging Anishinaabek	North Spirit Lake
Bingwi Neyaashi Anishinaabek	Northwest Angle No. 33
Cat Lake	Obashkaandagaang
Constance Lake	Ojibway Nation of Saugeen
Couchiching	Ojibways of Onigaming
Deer Lake	Ojibways of Pic River
Eabametoong	Pays Plat
Eagle Lake	Pic Mobert
Fort William	Pikangikum
Ginoogaming	Poplar Hill
Grassy Narrows	Rainy River
Gull Bay	Red Rock Indian Band

First Nation Communities	
Iskatewizaagegan Independent	Sachigo Lake
Kasabonika Lake	Sandy Lake
Keewaywin	Seine River
Kingfisher Lake	Shoal Lake No.40
Kitchenuhmaykoosib Inninuwug	Slate Falls
Lac Des Mille Lacs	Wabaseemoong Independent Nation
Lac La Croix	Wabauskang
Lac Seul	Wabigoon Lake Ojibway Nation
Long Lake No. 58	Wapekeka
Marten Falls	Wawakapewin
McDowell Lake	Webequie
Mishkeegogamang	Whitesand
Mitaanjigaming	Wunnumin Lake
Muskrat Dam Lake	

3.1 Previous Regional Planning Cycle & Status Update

The previous Northwest Scoping Assessment Outcome Report was published in January 2015 and recommended four sub-regions each with their own IRRP:

- Greenstone-Marathon (published June 2016)
- Thunder Bay (published December 2016)
- West of Thunder Bay (published July 2016)
- North of Dryden (already underway at the time of the Scoping Assessment; published January 2015)

Each IRRP is briefly summarized below.

Greenstone-Marathon IRRP

The Greenstone-Marathon sub-region is located northeast of Thunder Bay and is electrically supplied from Marathon TS and Alexander SS. The recommendations for system enhancements were heavily dependent on two industrial customers – a Geraldton area mine and the Energy East Pipeline. Since the IRRP was published, neither industrial customers have connected to the system and, as such, no system enhancements were needed.

The 2020 Needs Assessment identified higher than previously forecast load distribution connected load growth which could cause capacity needs in the area and warrants further investigation in the current regional planning cycle.

Thunder Bay IRRP

Thunder Bay sub-region consists of the 115 kV network supplied from Lakehead TS (except A4L which is included in the Greenstone-Marathon IRRP). No enhancement was necessary under the low and medium demand forecast scenarios. The high demand forecast scenario showed that system enhancements may be necessary. To supply the high demand scenario, the IRRP identified potential options including new autotransformers at Lakehead TS or Birch TS and local generation. Additionally, the IRRP recommended further investment at Port Author TS if demand growth materialized.

The 2020 Needs Assessment noted that refurbishment work scheduled for 2025 at Port Author TS would increase the station capacity. The Needs Assessment also identified higher than anticipated growth in the area, in excess of the previous IRRP's high scenario, which could introduce additional capacity needs.

West of Thunder Bay IRRP

The West of Thunder Bay sub-region is comprised of the diamond-shaped 230 kV system from Mackenzie TS to Kenora TS as well as the surrounding 115 kV sub-systems (Kenora 115 kV, Dryden 115 kV, Moose Lake 115 kV, Fort Frances 115 kV). No enhancements were necessary under the low and reference demand forecast scenarios. The high demand forecast scenario showed that Dryden 115 kV sub-system reinforcements may be necessary. The IRRP identified local generation and additional autotransformers as potential options should load growth materialize.

While the 2020 Needs Assessment did not specifically identify any new capacity needs in this area, a refresh of the high scenario and associated options is warranted.

North of Dryden IRRP

The North of Dryden sub-region is comprised of the 115 kV system north of Dryden TS supplied by E4D circuit. The IRRP identified that the sub-region was at capacity and new infrastructure was needed to supply forecast growth and remote connections. The IRRP findings supported the 230 kV single circuit to Pickle Lake option (also known as the Wataynikaneyap or Watay Project) which was previously identified as a priority project in the 2010 and 2013 Long-Term Energy Plan. A subsequent 2016 letter from the IESO to the OEB outlined the recommended scope of the new line to Pickle Lake and Remote Connections Project. Implementation of the Wataynikaneyap Project (further described in Section 3.2) started shortly thereafter and is now near completion. The 2020 Needs Assessment found that the new Watay project provides relief to the E1C circuit and Red Lake sub-system capacity needs. Nevertheless, this area continues to have the potential for high mining-related load growth and warrants further study in the current regional planning cycle.

3.2 Major Transmission System Reinforcements

Two new transmission system projects, the East-West Tie ("EWT") reinforcement and Wataynikaneyap Transmission Project ("Watay Project"), discussed above, are nearing completion. These projects are assumed to be in service for the purpose of the current regional planning cycle. The EWT reinforcement adds four new 230 kV circuits: M37L and M38L from Lakehead TS to Marathon TS and W35M and W36M from Marathon TS to Wawa TS. The Watay Project includes a new 230 kV circuit between Watay 230/115 kV TS and Dinorwic Jct on circuit D26A. Ten remote First Nation communities north of Pickle Lake will be electrically supplied by Watay TS. An additional six remote First Nation communities north of Red Lake are electrically supplied by a switching station that taps onto the circuit E2R adjacent to Balmer Jct.

Development work is currently underway for the Waasigan Transmission Line which is another potential transmission system reinforcement between Thunder Bay to Atikokan and from Atikokan to Dryden to address potential bulk system needs. The IESO continues to monitor the needs in this area and, as such, a commitment to construct the line has not been made. For this reason, the Waasigan Transmission Line is not assumed to be in service for the purpose of this regional planning cycle. In addition, the need and timing of bulk system reinforcements are not included in the scope of regional planning. This is further discussed in Section 5.

4. Summary of New and Updated Needs

The first phase of the current regional planning cycle, the Hydro One-led Needs Assessment, was completed in July 2020.

This section briefly summarizes the new and updated needs identified in the Needs Assessment report. Please refer to the full Needs Assessment report for more details. The system capacity, station capacity, load security/restoration, and end of life needs are described in the following subsections. Note that this section documents all identified needs regardless of whether or not further regional coordination is warranted. Section 5 specifies the planning approach and outlines the specific needs that will be in scope for subsequent regional planning stages.

4.1 System Capacity Needs

System capacity (or "load meeting capability") refers to the ability of the electricity system to supply power to customers in the area either by generating the power locally or bringing it in through the transmission system. System capacity needs were identified in the Needs Assessment report for the Thunder Bay Area and the Marathon Area as described in Table 4-1.

Table 4-1 | System Capacity Needs

Need #	Station/Circuit	Description of Need
1	Lakehead TS, A5A, A1B,T1M	Voltage support will be required to prevent voltage collapse for loss of both Lakehead TS autotransformers. Mitigation is required to prevent overloading of circuits A5A, A1B, and T1M under this outage condition. The Needs Assessment recommended further studies in subsequent stages of regional planning.
2	Marathon TS, A5A	Voltage support will be required to prevent voltage collapse for the loss of both Marathon TS autotransformers. Mitigation is required to prevent overloading of circuit A5A under this outage condition. The Needs Assessment recommended further studies in subsequent stages of regional planning.

4.2 Station Capacity Needs

Station capacity refers to the ability to convert power from the transmission system down to distribution system voltages. Station capacity needs were identified at Kenora MTS, Sapawe DS, and Sam Lake DS as described in Table 4-2.

Table 4-2 | Station Capacity Needs

Station	Assessment
Kenora MTS	Kenora MTS is expected to reach capacity by 2027. The Needs Assessment recommended local planning to address this need. This Scoping Assessment revisited this need and will include it in scope for further evaluation in regional planning. Please see Section 5.2 for more details.
Sapawe DS	Load growth at Sapawe DS is expected to reach the Winter and Summer Planned Loading Limit by 2028 and 2026 respectively. The Needs Assessment recommended distribution planning to address this need.
Sam Lake DS	Sam Lake DS is already at capacity. Due to the significant load increase, additional voltage support will also be required at this station. The Needs Assessment recommended that Sioux Lookout Hydro, Hydro One Distribution and Hydro One Transmission collaborate to address this need in local planning.

4.3 Load Security and Restoration Needs

Load security describes the total amount of load interrupted following major transmission outages. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes.

The Needs Assessment did not identify any load security or load restoration needs. The Northwest region has many 115 kV radial circuits and / or single transformer connected stations where loss of load is anticipated after a single contingency. The magnitude of load interrupted is within the allowable limits and the load restoration criteria is met since the standards allow for leeway in remote locations. Nevertheless, outages have high socio-economic costs for impacted communities and, so, the Needs Assessment recommended that load restoration be further investigated in subsequent stages of regional planning. Alleviating this impact with additional system investments can often be cost prohibitive unless they can be integrated with solutions designed to meet needs driven by criteria violations. Impacted radial circuits include but not limited to:

- 115 kV A4L (Alexander SS x Longlac TS)
- 115 kV M2W (Marathon TS x White River DS)
- 115 kV E2R (Ear Falls TS x Red Lake TS)
- 115 kV C2M (Pickle Lake SS x Musselwhite CSS)
- 115 kV K3D (Sam Lake DS x Dryden TS)
- 115 kV 29M1 (Ignace Jct x Mattabi CTS)
- 115 kV M1S (Moose Lake TS x Crilly DS)
- 115 kV A6P/56M1/57M1 (Alexander SS x Port Arthur TS x Red Rock DS)
- 115 kV P5M/S1C (Port Arthur TS x Lac Des Iles Mine CTS)

4.4 End of Life Needs

The Needs Assessment identified numerous facilities approaching end of life over the next 10 years as described in Table 4-3 and 4-4. Replacements for these facilities can be like-for-like, right-sized, or retired depending on system needs. The Needs Assessment recommended coordination with the IESO when required and where feasible.

Table 4-3 | End of Life Circuit Equipment

Station/ Circuit	Timing	Details
A4L	2025	Refurbishment of Beardmore Jct x Longlac TS section.
E1C	2025	Ear Falls TS x Slate Falls DS section and Etruscan Jct x Crow River DS section have been prescribed for line refurbishment.

Table 4-4 | End of Life Station Equipment

Station/ Circuit	Timing	Details
Alexander SS	2022	Existing HV breaker and line switches have reached EOL
Ear Falls TS	2022	Existing HV breaker at the station is reaching EOL
Fort Frances TS	2027	The two (2) 230/115 kV step-down auto-transformer and 115 kV breakers at the station are reaching EOL
Kenora TS	2025	The existing step-down auto-transformer, as well as HV breakers and switches are reaching EOL
Lakehead TS	2025	The existing HV breakers, switches, and Protection & control facilities at the station are approaching EOL
Mackenzie TS	2024	The existing 230/115 kV auto-transformer, as well as HV breakers and line disconnect switches are near EOL
Marathon TS	2024	The existing HV breakers at this station is approaching EOL
Moose Lake TS	2024	The existing two (2) 115/44kV Step-Down Transformer and LV breakers are near EOL

Station/ Circuit	Timing	Details
Port Arthur TS #1	2025	Due to equipment limitations and EOL assets on the LV side of the station, the station has been limited to provide up to 55MW. Once the LV yard refurbishment is complete in 2025, the station capacity will increase to 59MW
Rabbit Lake SS	2022 2024	New HV load break switch installs are due for completion in 2022, while the existing HV breaker / disconnect switches, and line disconnect switches are also near EOL and plans are in place to replace them by 2024
Whitedog Falls SS	2023	The existing 115 kV breakers, and line disconnect switches at the station are near EOL

5. Regional Planning Approach

Needs identified through the Needs Assessment (NA) were reviewed during the Scoping Assessment to determine whether a Local Plan ("LP"), Regional Infrastructure Plan ("RIP"), or Integrated Regional Resource Plan ("IRRP") regional planning approach is most appropriate.

An Integrated Regional Resource Plan is recommended for the Northwest region. The Needs Assessment flagged several needs that may require further regional coordination and has potential impacts to the bulk system. Upon further consideration, this Scoping Assessment concurs with Needs Assessment. Additionally, there is a high degree of stakeholder and community interest.

The following sections outline the selection criteria, and the scope of the recommended IRRP.

5.1 Selection Criteria

The three potential planning outcomes are designed to carry out different functions and selection should be made based on the unique needs and circumstances in each area. The criteria used to select the regional planning approach within each sub-region are consistent with the principles laid out in the PPWG Report to the Board[1], and are discussed in this document to ensure consistency and efficiency throughout the Scoping Assessment.

IRRPs are comprehensive undertakings that consider a wide range of potential solutions to determine the optimal mix of resources to meet the needs of an area for the next 20 years, including consideration of non-wires alternatives, conservation, generation, new technologies, and wires infrastructure. RIPs focus instead on identifying and assessing the specific wires alternatives and recommend the preferred wires solution for an area and are thus narrower in scope. LPs have the narrowest scope; only considering simple wires solutions that do not require further coordinated planning.

A LP process is recommended when needs:

- Are local in nature (only affecting one LDC or customer)
- Are limited investments of wires (transmission or distribution) solutions
- Do not require upstream transmission investments
- Do not require plan level community and/or stakeholder engagement and,
- Do not require other approvals such as a Leave to Construct application or Environmental Approval.

If it is determined that coordinated planning is required to address identified needs, either a RIP or an IRRP may be initiated. A series of criteria have been developed to assist in determining which planning approach is the most appropriate based on the identified needs. In general, an IRRP is initiated wherever:

[1] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

- A non-wires measure has the potential to meet or significantly defer the needs identified by the transmitter during the Needs Assessment;
- Community or stakeholder engagement is required; or,
- The planning process or outcome has the potential to impact bulk system facilities

If it is determined that the only feasible measures involve new/upgraded transmission and/or distribution infrastructure, with no requirement for engagement or anticipated impact on bulk systems, a RIP will be selected instead.

Wires type transmission/distribution infrastructure solutions refer, but are not limited, to:

- Transmission lines
- Transformer/ switching stations
- Sectionalizing devices including breakers and switches
- Reactors or compensators
- Distribution system assets

Additional solutions, including conservation and demand management, generation, and other electricity initiatives can also play a significant role in addressing needs. Because these solutions are non-wires alternatives, they must be studied through an IRRP process.

5.2 Integrated Regional Resource Plan Scope of Work

Whereas the previous regional planning cycle divided the region into 4 sub-regions, this Scoping Assessment recommends a single IRRP that covers the entire Northwest region but focuses on specific issues highlighted in this section.

Note that the primary purpose of an IRRP is to study needs that require coordination between transmitters, distribution companies, and the IESO. The IRRP will not study bulk system needs such as transfer capability on the 230 kV system, need/timing of the Waasigan Project, and intertie capability with Manitoba/Minnesota. However, the load forecast developed during the IRRP will inform bulk system studies. Additionally, the IRRP will not specifically address new customer transmission connection requests unless there is an opportunity to align with broader regional needs. While the IRRP welcomes information from project proponents to inform load forecasting and to ensure plans for regional infrastructure are adequate, individual customers connection requests may be better suited for a proponent driven Technical Feasibility Study.

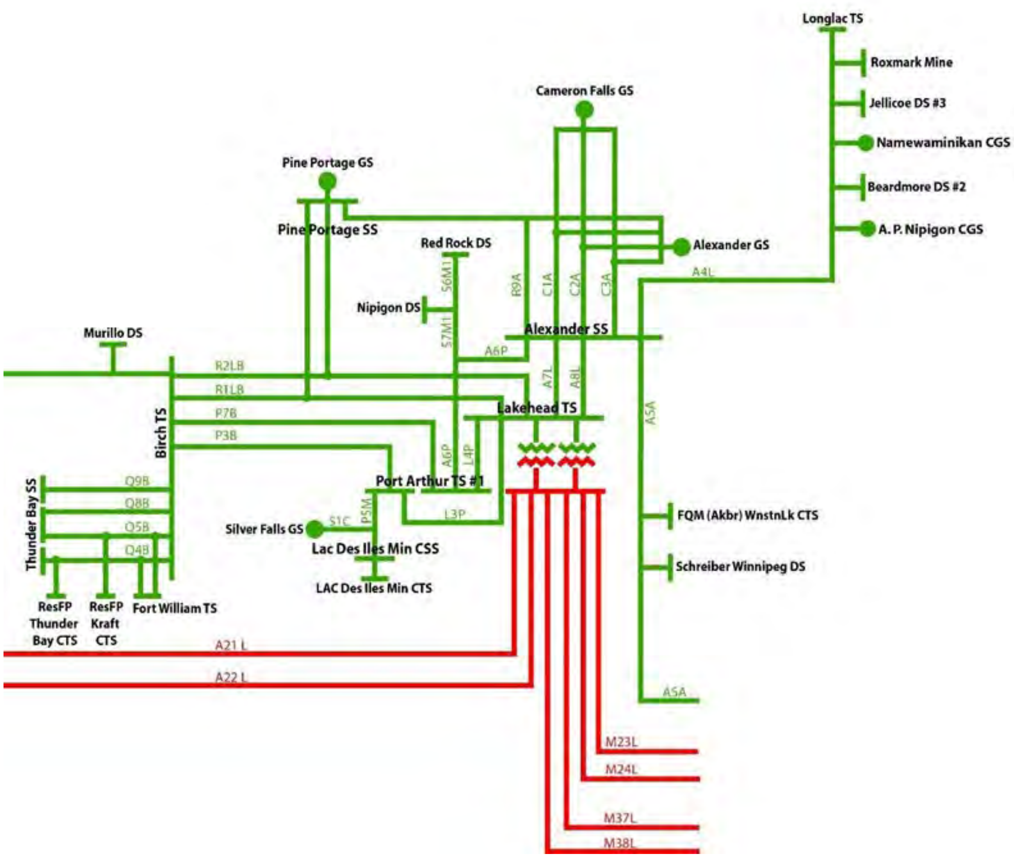
The IRRP will focus on the needs described below.

Thunder Bay Area Capacity Need

The Needs Assessment identified a potential capacity need at Lakehead TS and downstream 115 kV system. Specifically, voltage collapse and overloading on A5A were identified under a N-1-1 contingency where both autotransformers are out of service. Lakehead TS is the primary supply point for the City of Thunder Bay and surrounding area. A single line diagram of the area is show in Figure 5-1.

The IRRP will further study drivers of load growth and the timing of the need. This area has significant hydro generation which will be further studied to update the dependable generation assumption.

Figure 5-1 | Single Line Diagram of the Thunder Bay Area

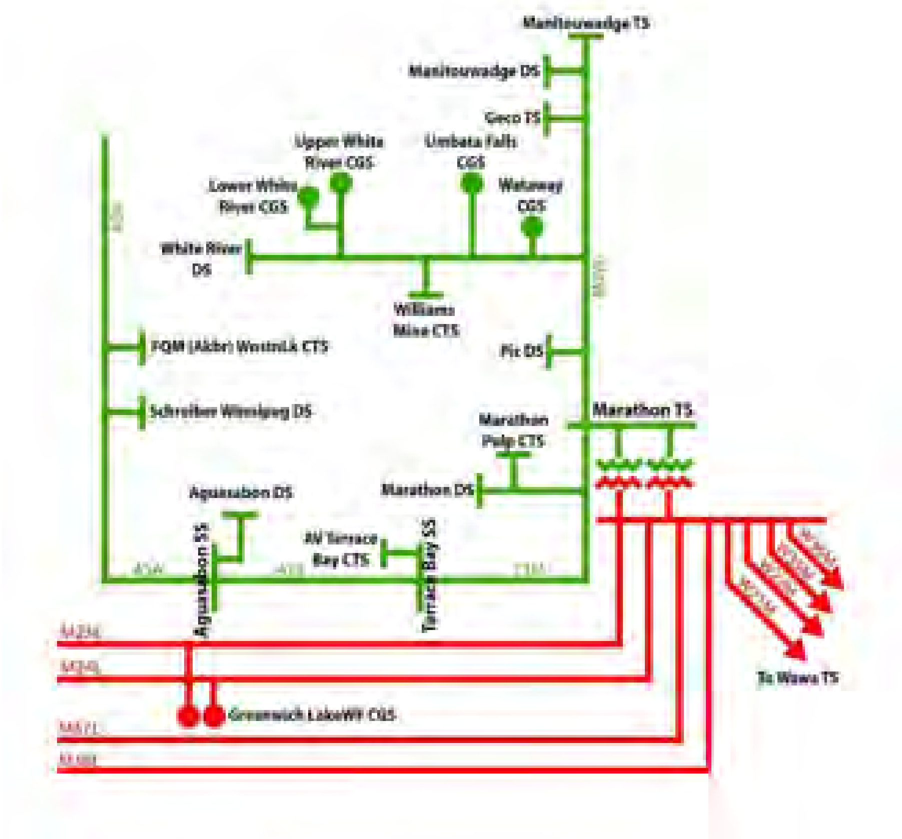


Marathon Area Capacity Need

The Need Assessment identified a potential capacity need at Marathon TS and downstream 115 kV system. Similar to the Thunder Bay capacity need, voltage collapse and thermal overload on A5A were identified. Marathon TS supplies the Town of Marathon, Manitouwadge in the north, White River in the east, and communities on the north shore of Lake Superior. A single line diagram of the area is show in Figure 5-2.

The IRRP will further study drivers of load growth and the timing of the need. As with the Thunder Bay area, there is significant hydro generation which will be further studied to update the dependable generation assumptions.

Figure 5-2 | Single Line Diagram of the Marathon Area

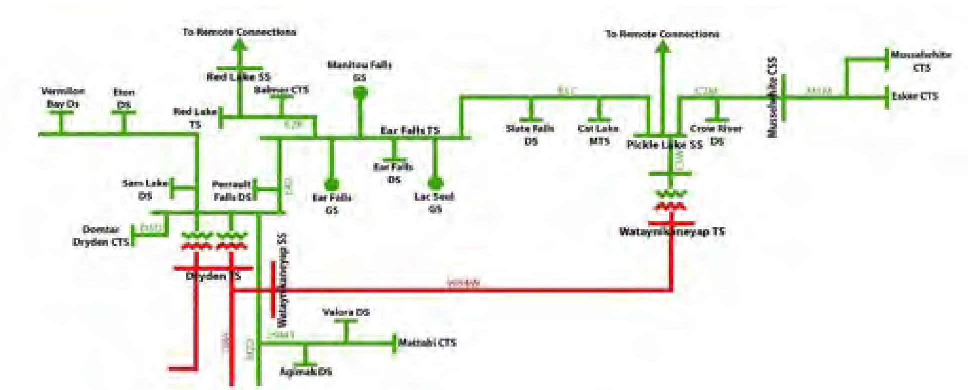


Refresh North of Dryden Area System Capability

The Dryden area includes Dryden TS, the 230 kV system north of Dinorwic Jct, and the 115 kV system served from these two supply points. A single line diagram of the area is shown in Figure 5-3. Although no needs were flagged for this area in the Needs Assessment, there have been significant system topology changes (Wataynikaneyap Project and remote connections) since the last regional planning cycle. This area also has a high concentration of mining developments which contributes to a high degree of uncertainty in the load forecast.

The IRRP will refresh previous studies to assess the capability of the existing system and study potential options to be triggered if future needs materialize.

Figure 5-3 | Single Line Diagram of the Dryden Area



Non-Wires Alternatives for Kenora MTS Capacity Need

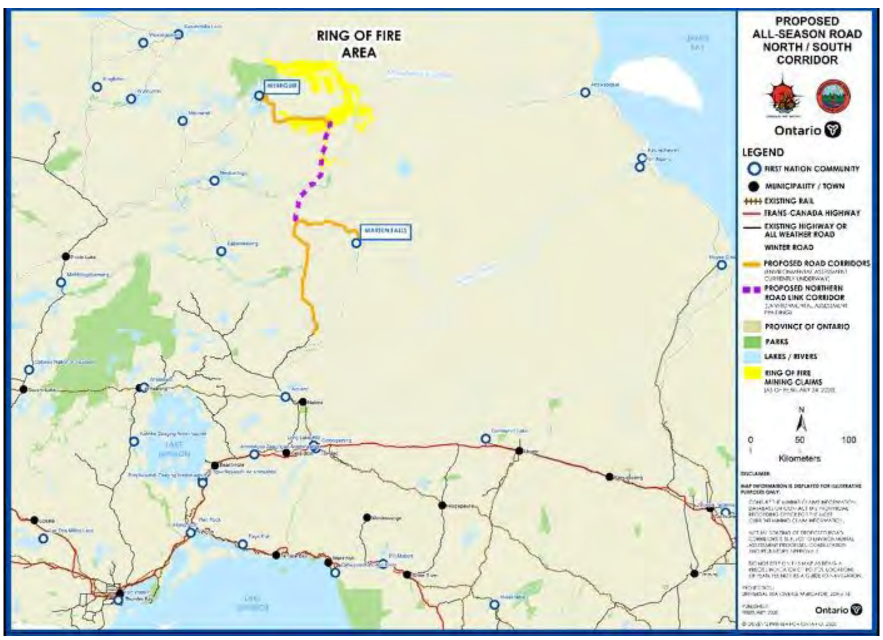
Kenora MTS serves the City of Kenora and is expected to reach capacity around 2027. The Needs Assessment originally recommended that this need be addressed through local planning but, upon further examination, the timing of the need and the rate of growth at Kenora MTS suggests non-wires alternatives may be possible.

The IRRP will perform a preliminary assessment to determine if non-wires options are feasible from a cost, reliability and implementation perspective. If not, local planning between Synergy North and Hydro One will continue to develop a station expansion/modification solution as recommended in the Needs Assessment.

Ring of Fire Connection Scenario

The Ontario provincial government's agreement to support the Northern Road Link puts renewed focus on Ring of Fire developments. A map of the proposed road is show in Figure 5-4. The IRRP will assess the capability of the local electricity system to accommodate new load at the Ring of Fire. Note that, if warranted, the development of a specific connection plan will likely be addressed in a separate study following the IRRP.

Figure 5-4 | Proposed All-Season Road (Source: Government of Ontario)



Load Restoration

As stated in the Needs Assessment, the Northwest region has many radial single circuit supplied load stations. These stations are not in violation of load restoration criteria since the standards allow for leeway given their remote location. Nevertheless, outages have high socio-economic costs for impacted communities and traditional wires solutions are often cost prohibitive. Given the high degree of stakeholder interest, the IRRP will investigate opportunities for incremental improvements (including non-wires solutions) where there is the potential for integration with other system needs and where cost effective. This is consistent with the IESO's Customer Reliability Review[2] completed in 2019.

End of Life

The Needs Assessment identified numerous facilities nearing end of life over the next 10 years. The majority of these anticipated facility replacements are minor and do not have the potential to impact other system needs. However, there are several more significant facilities nearing end of life including step-down transformers at Moose Lake TS, autotransformers at Fort Frances TS, Kenora TS, and Mackenzie TS as well as segments of A4L and E1C. The IRRP will, where feasible within the timelines afforded by each project, examine opportunities to align the replacement of these facilities with other regional needs.

[2] http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Customer-Reliability-Review

6. Conclusion and Next Steps

This Scoping Assessment concludes that a single IRRP covering the entire region will be undertaken to address the following items as discussed according to Section 5.2:

- Thunder Bay Area Capacity Need
- Marathon Area Capacity Need
- Refresh North of Dryden Area System Capability
- Non-Wires Alternatives for Kenora MTS Capacity Need
- Ring of Fire Connection Scenario
- Load Restoration
- End of Life

Note that this list is not exhaustive. As further technical studies and community engagement are undertaken through the IRRP, new needs may come to light and be included in the scope of the IRRP. Additionally, the IRRP process is expected to be carried out in a manner that allows for continuous coordination of information with ongoing bulk system studies. In particular, the load forecast from the IRRP will be leveraged to better understand the drivers of load growth and further refine the need date for the Waasigan Transmission Line. The draft Terms of Reference for the Northwest IRRP can be found in Appendix 2.

Furthermore, this Scoping Assessment concurs with the Needs Assessment recommendation to address the Sapawee DS and Sam Lake DS capacity needs through distribution and local planning, respectively.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
CTS	Customer Transformer Station
DER	Distributed Energy Resources
DG	Distributed Generation
DS	Distribution Station
EWT	East-West Tie
FIT	Feed-in-Tariff
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
JCT	Junction
kV	kilovolt
LDC	Local Distribution Company
LP	Local Plan
MTS	Municipal Transformer Station
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SS	Switching Station
TS	Transformer Station

Appendix 2 – Northwest IRRP Terms of Reference

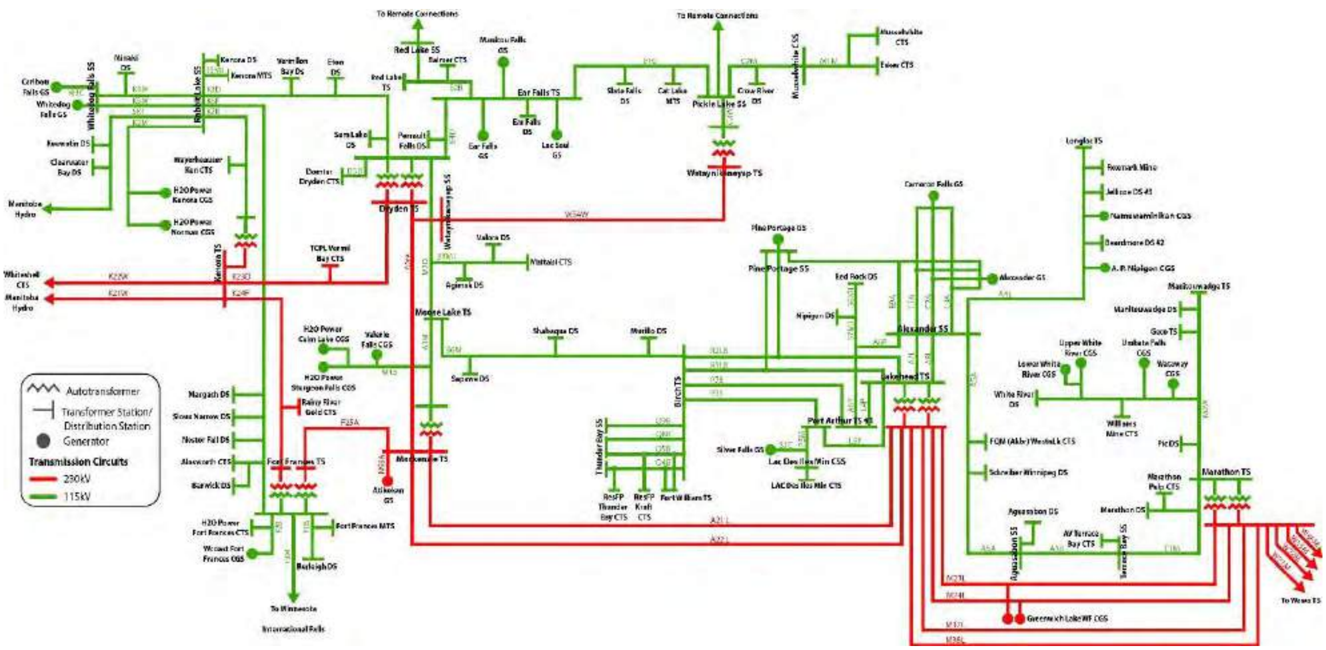
1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) of the Northwest region.

Based on the potential for demand growth within this region, limits on the capability of the transmission capacity supplying the area, and opportunities for coordinating demand and supply options, an integrated regional resource planning approach is recommended.

The single line diagram is shown in Figure A-1.

Figure A-1 | Northwest Region



The previous Northwest Scoping Assessment was published in January 2015 and recommended four sub-regions each with their own IRRP. These IRRPs include Greenstone-Marathon (published June 2016), Thunder Bay (published December 2016), West of Thunder Bay (published July 2016), North of Dryden (published January 2015).

The first phase of the current regional planning cycle, the Hydro One-led Needs Assessment, was completed in July 2020.

2. Objectives

The Northwest IRRP will assess the adequacy of electricity supply to customers in the region and will develop a set of recommended actions to maintain reliability of supply to the region over the next 20 years.

- Assess the adequacy of electricity supply to customers in the Northwest area over the next 20 years;
- Determine whether there is a need to initiate development work or to fully commit infrastructure investments in this planning cycle;
- Identify and coordinate major asset renewal needs with regional needs, and develop a flexible, comprehensive, integrated electricity plan for Northwest; and,
- Develop an implementation plan that is flexible in order to accommodate changes in key assumptions over time, while keeping options viable.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Northwest region. The plan is a joint initiative involving, Hydro One Networks Inc. (Transmission), Hydro One Networks Inc. (Distribution), Atikokan Hydro Inc., Fort Frances Power Corporation, Sioux Lookout Hydro Inc., Synergy North and the IESO. These organizations are defined as the Working Group for the Northwest IRRP.

The plan will focus on these specific items:

- Thunder Bay Area Capacity Need
- Marathon Area Capacity Need
- Refresh North of Dryden Area System Capability
- Non-Wires Alternatives for Kenora MTS Capacity Need
- Ring of Fire Connection Scenario
- Load Restoration
- End of Life
- Any additional needs that emerge in carrying out the IRRP

Like all IRRPs, the Northwest IRRP will integrate: forecast electricity demand growth, conservation and demand management ("CDM") in the area, distributed energy resources ("DER") uptake, transmission and distribution system capability, relevant community plans, and bulk system developments as applicable.

Based on the identified needs, the Northwest IRRP process will consist of the following activities:

1. Development of a Stakeholder Engagement Plan.

2. Development of an updated 20-year demand / load forecast for the entire region. The forecast will be used to confirm that there are no significant changes from past IRRPs in areas where no needs were flagged in the 2020 Needs Assessment. In areas with potential capacity needs (such as the Thunder Bay and Marathon areas), the forecast will be compared against the load meeting capability to determine the timing of needs.
3. Assessment of the adequacy of transformer station ratings, load meeting capabilities and reliability.
    a. Identify or confirm the transformer station capacity needs and sufficiency of the area's load meeting capability for the study period using the updated load forecast.
    b. Confirm identified restoration and security needs using the updated load forecast.
    c. Collect information on any known reliability issues and load transfer capabilities from the Local Distribution Companies ("LDCs").
4. Assessment of options for confirmed needs. Options are evaluated on the basis of technical feasibility, economics, and reliability performance as well as consideration of other factors raised through community engagement.
5. Development of the long-term recommendations and the implementation plan.
6. Completion of the IRRP report documenting the near-, mid-, and long-term needs and recommendations.

Depending on the nature and the urgency of the electricity needs and risks identified, the IRRP could recommend a combination of the following actions:

- Active monitoring
- Project development work to shorten lead time for the project, without firm commitment for constructing the project
- Commitment of Project and Proceed with Project Implementation (e.g., resources acquisition, transmission procurement, regulatory approval)
- Interim measures to manage the near-term requirements, until longer-term solutions could come into service
- Additional pilots, studies and/or engagement to gather more information
- Coordination with other planning or related processes (e.g., community or bulk system planning)

Should the IRRP identify the need for infrastructure investment, the IRRP will provide a rationale and define high-level project requirements to support project development and implementation to be carried out by other proponents. The outcomes from the IRRP will help inform transmitter and LDC rate filings and any related transmission/resources acquisitions processes that may result.

It is important to note that detailed discussion of acquisition mechanisms, cost allocation, cost recovery, siting, operations and implementation of recommended projects are beyond the scope of IRRP.

In order to carry out this scope of work, the working group will consider the data and assumptions outlined in Section 4 below.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data
  - Historical coincident peak demand information
  - Historical weather data (temperature, humidity, consecutive cooling/heating days, etc.) for the purpose of correcting demand for median/extreme weather conditions
  - Gross peak demand forecast scenarios by sub-region, TS, etc.
  - Identified potential future load customers
- Conservation and Demand Management
  - Conservation forecast for LDC customers, based on sub-region's share of current energy efficiency programs
  - Local Achievable Potential Studies
  - Potential for CDM at transmission-connected customers' facilities
- Local resources
  - Existing local generation, including distributed generation (DG), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
  - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
  - Future district energy plans, combined heat and power, energy storage, or other generation proposals
- Relevant local plans, as applicable
  - LDC Distribution System Plans
  - Community Energy Plans, Municipal Energy Plans and Climate Action Plans
  - Municipal Growth Plans
  - Indigenous Community Energy Plans
- Criteria, codes and other requirements
  - Ontario Resource and Transmission Assessment Criteria (ORTAC)
    1. Supply capability
    2. Load security
    3. Load restoration requirements

- NERC and NPCC reliability criteria, as applicable
- OEB Transmission System Code
- OEB Distribution System Code
- Reliability considerations, such as the frequency and duration of interruptions to customers
- Other applicable requirements

- Existing system capability
    - Transmission line ratings as per transmitter records
    - System capability as per current IESO PSS/E base cases
    - Transformer station ratings (10-day LTR) as per asset owner
    - Load transfer capability
    - Technical and operating characteristics of local generation
    - Bulk System considerations to be applied to the existing area network
- End-of-life asset considerations/sustainment plans
    - Transmission assets
    - Distribution assets
- Other considerations, as applicable

5. Technical Working Group

The core Technical Working Group will consist of planning representative/s from the following organizations:

- Independent Electricity System Operator (Team Lead for IRRP)
- Hydro One Networks Inc. (Hydro One Transmission)
- Hydro One Networks Inc. (Hydro One Distribution)
- Atikokan Hydro Inc.
- Fort Frances Power Corporation
- Sioux Lookout Hydro Inc.
- Synergy North
- Other transmitters and distributors as needed

Authority and Funding

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to that entity under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

6. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to and adopted by the provincial government to enhance the regional planning and siting processes in 2013.

As such, the IESO, in consultation with the Technical Working Group, is committed to conducting engagement in accordance with IESO Engagement Principles throughout the development of the IRRP. The first step in engagement will consist of the development of an engagement plan, which will be made available for comment before it is finalized. The data and assumptions as outlined in Section 4 will help to inform the scope of community and stakeholder engagement to be considered for this IRRP.

7. Activities, Timeline, and Primary Accountability

Num	Activity		Deliverable(s)	Timeframe
1	**Develop the Planning Forecast, including scenarios for sensitivity analyses, as required**	*IESO / LDCs with input from Hydro One*	Long-term planning forecast scenarios	Feb 2021 – Apr 2021
1.1	Establish historical coincident and non-coincident peak demand information	*IESO*		
1.2	Establish historical weather correction, median and extreme conditions	*IESO*		
1.3	Establish gross peak demand forecast for LDC service areas	*LDCs*		
1.4	Establish existing, committed and potential DG	*LDCs*		
1.5	Establish near- and long-term conservation forecast based on planned energy efficiency activities and codes and standards	*IESO*		
1.6	Develop planning forecast scenarios for sensitivity analyses	*IESO*		
2	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	Load transfer capabilities under normal and emergency conditions	Feb 2021 – Apr 2021
3	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	Relevant community plans	Feb 2021 – Apr 2021

Num	Activity		Deliverable(s)	Timeframe
4	**Complete system studies to identify needs over a twenty-year period**	*IESO, Hydro One Transmission*	Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q2-Q3 2021
4.1	Obtain PSS/E base case including bulk system assumptions as identified in Section 3.2			
4.2	Apply reliability criteria as defined in ORTAC			
4.3	Confirm and refine the need(s) and timing/load levels			
5	**Develop Options and Alternatives**		Develop flexible planning options for forecast scenarios	Q3-Q4 2021
5.1	Develop energy efficiency options, with consideration for previous LAPS findings	*IESO and LDCs*		
5.2	Develop local generation options, with consideration for previous LAPS findings	*IESO and LDCs*		
5.3	Develop transmission and distribution options	*IESO, Hydro One Transmission, and LDCs*		
5.4	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
5.5	Develop portfolios of integrated alternatives	*All*		
5.6	Technical comparison and evaluation	*All*		
6	**Plan and Undertake Community & Stakeholder Engagement**	*IESO / LDCs and Hydro One with support as needed*	Community and Stakeholder Engagement Plan; Input from local communities	Ongoing as required
6.1	Early engagement including with local municipalities and First Nation communities within study area, First Nation communities who may have an			

Num	Activity		Deliverable(s)	Timeframe
	interest in the study area, and the Métis Nation of Ontario			
6.2	Develop communications materials			
6.3	Undertake community and stakeholder engagement			
6.4	Summarize input and incorporate feedback			
7	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	Implementation plan; Monitoring activities and identification of decision triggers; Procedures for annual review	Q1-Q2 2022
8	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	IRRP report	July 2022

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.

Appendix J

2022 Remotes Business Plan

Hydro One Remote Communities Inc.

2022-27 Business Plan

October 22, 2021

Hydro One Remote Communities Inc.

Hydro One Remote Communities (Remotes) generates and distributes electricity to customers in 21 off-grid communities and is also the distributor to one community connected to the province's electricity grid. It is 100% debt financed and is operated as a break-even company, with net income of zero in all years over the Plan period, and with adjustments to the system wide Rural or Remote Electricity Rate Protection (RRRP) charge to recover variances in net income each year.

Seventeen of the communities currently served by Remotes are First Nation communities, isolated and scattered across Ontario's far north. These communities face many challenges and are economically disadvantaged. The capital required to meet community load growth is funded by the federal government in all off-grid communities. Consequently, work is planned and executed in close collaboration with the First Nations communities, their Tribal Councils and Indigenous Services Canada. We engage First Nations in its business as employees, contractors, local operators[1] and meter readers. Many of our suppliers are First Nation enterprises or have a First Nation component to their business. Due to government regulation, Remotes' customer rates are not set to the cost of service model. Residential customers pay rates far below the cost of service. Customer rates have historically increased by the rate of inflation each year.

Strategic Goals

Consistent with Hydro One's overall goals and with our vision and mission, Remotes' 2022 business plan is designed to meet the following objectives:

- Create an injury-free workplace and protect the safety of the public
- Supply safe, reliable, and affordable electricity to our customers
- Offer an exceptional customer experience
- Build strong, respectful relationships with community leaders
- Improve the safety, reliability and efficiency of distribution and generation systems
- Build a culture of actively engaged employees, with the skills and ability to respond to our customers' needs
- Protect and sustain the environment for future generations

Business Context

In 2016, the provincial government designated Wataynikaneyap Power Limited Partnership (Watay) to construct a Transmission (Tx) line to connect 16 remote First Nation communities to the grid of which 10 are currently served by Remotes and 6 are unregulated Independent Power Authorities (IPAs).

In the spring of 2019, the OEB approved Watay's $1.3 billion Leave to Construct. As part of the Tx connection project, all IPA communities have requested distribution services from Remotes. Watay has selected Valard Construction as the engineering-procurement-construction (EPC) provider with the plan to connect communities starting in 2022, with all communities connected by the end of 2024. The proposed cost recovery framework will charge the cost of the Tx facilities to Remotes as a direct expense, which will be recovered through the RRRP. Watay has projected the cost to Remotes will grow to be approximately $104M per year over the Plan period. These Tx tariffs will be only partially offset by fuel and maintenance savings.

Remotes continues to be focused on growth and operational excellence over the next five years. Remotes will continue to concentrate on providing safe, reliable and affordable electricity to customers through diesel generation and distribution services. Remotes will grow the business by acquiring new communities through the Watay grid development project. The development and implementation of a back-up generation service to new and existing communities will be a shift for operations and unique for a utility

[1] Operators: Employees of the First Nation Band Council who perform daily operations and minor maintenance in Remotes' generating stations.

in the province. Over the Plan period, Remotes will see increased complexity in the business as the service territory grows and transitions from an embedded to Tx connected distributor while continuing to offer off-grid generation and distribution services.

Major Initiatives

Remotes expects to integrate 6 new unregulated distribution systems into its service territory over the next three years. Significant effort from Watay and Remotes will be required to ensure that community readiness and a smooth transition to regulated service occurs. Proposed Tx development by Watay Power will drive major changes in Remotes' business, resulting in a 40% increase in customers, new settlement and financial processes, increased interaction with government, First Nations, Tribal Councils and industry regulators. Changes to operations include: on-grid operating and connection agreements; coordination with other distributors and transmitters; as well as, new processes and assets.

All of the communities connecting to the grid through the Watay transmission system are currently supplied with locally generated electricity, primarily from diesel fuel. In general, supply from local generation is more reliable than supply transmitted over long radial lines. Consequently, Remotes continues to work with both the federal and provincial governments, the local communities and their project partners on providing reliable back-up power in communities post connection.

Remotes will continue to serve 12 off-grid communities once the Watay project is complete. Remotes will continue to manage its business based on the principles of operational excellence and continuous improvement in all aspects of operations. Safe, reliable and affordable electricity are valued by Hydro One customers and will underpin all decisions and investments.

Significant Assumptions and Interdependencies

- The Watay project will be fully in service by 2024, with two communities connecting in 2022, nine in 2023, and five in 2024.
- The Watay project including the proposed cost recovery framework is approved by the OEB as filed.
- Customer rates are expected to increase by inflation each year. The RRRP changes each year to reflect forecasted costs.
- Standard "A" rates will be retained throughout the plan period, but lower Standard "A" rates will apply when communities are connected to the grid.
- Rural and Remote Rate Protection will continue for the plan period in its current form. The current Regulation does not cap the amount of rate protection available to remote customers.
- RRRP variance account will be retained and cleared through cost of service proceedings.
- Federal capital funding will be available for necessary shorter-term upgrade projects through the plan period.
- Back-up power will be initiated within the plan period in most newly grid connected communities.

Risks

Similar to prior years, three of our top risks remain: safety, transmission connection uncertainty, and Indigenous relationship uncertainty. Employee retention, succession and redundancy surfaced as a top risk in 2021. Remotes has on-going plans, programs and initiatives to actively manage and address these risks.

Safety

The risk of an employee or operator injury or fatality is a constant concern and is always a top priority. Controls in place include a long established and strong performing Environment, Health and Safety Management System, controls and process in place for all work activities, and safety moments at every meeting to keep safety top of mind. We continue to face the risk of a geographically dispersed service territory with both employees and operators working largely unsupervised. Training, procedures, compliance reviews, improvements to the sites, supervisory workplace inspections and support are partial controls for this risk.

Transmission Connection Uncertainty

By 2022, Remotes expects to be a transmission connected utility, which will mean that a number of new requirements will apply and new processes will need to be developed and implemented. The hybrid model created by serving on and off-grid communities will introduce a new level of complexity to Remotes which will necessitate a certain fluidity to the Plan as challenges are more comprehensively understood and mitigated. Challenges are expected in the collection and integration of IPA customer information to Remotes' systems, settlements and wholesale metering activities, as well as coordination and communications with a newly formed transmitter that has no operating experience and minimal operational resources deployed. To manage these risks, Remotes is working with Watay, IESO and Networks to develop a broader base understanding of requirements. Remotes will also leverage its experience gained in the Pikangikum transition. Watay project timelines have been negatively affected as a result of COVID and other construction challenges which introduce a level of uncertainty regarding community connection time frames and associated work.

Indigenous Relationship Uncertainty

Remotes operates in a unique, complex and often politically charged environment. Significant economic and social issues are facing the communities we serve. It is paramount that Remotes be viewed as a collaborative and trusted partner and wholeheartedly dedicated to exceptional customer and community experience in order to execute our growth strategy as the communities we serve choose their service provider. As well, all First Nations that we currently serve adhere to a two-year election cycle which introduces challenges to long-term relationship building with community leadership. Remotes will continue to develop customer and community programs to facilitate communication, develop understanding, meet customers' expectations, build capacity and promote Indigenous culture in order to foster strong and respectful relationships.

Employee Retention, Succession & Redundancy

Remotes faces multiple challenges: retaining a young workforce with highly marketable skills who may be reluctant to spend consistent time away from their families in the far north, the potential retirement of experienced staff and developing or finding supervisors and managers capable of wearing multiple hats. To manage these challenges, we actively seek to create an engaging work environment by investing in staff and creating development opportunities. There is a substantial focus on training for employees to enhance skills and learn new technologies. We have documented critical activities to assist new employees in taking over tasks and continue to develop and promote internal growth opportunities as well as providing rotations to apprentices and others to broaden the pool of Networks'employees with exposure and knowledge of Remotes. Additionally, we developed an employee-centered wellness program that responds to employees' suggestions on how to reduce stress and improve health within the workplace. Currently, over 25% of our employees are eligible for retirement, growing to 40% over the plan period. Succession planning for a small business is challenging as redundancy is minimal and many key roles are unique to Remotes thus making the attraction and development of new employees and apprentices critical to our long-term success.

Cost of Service

Remotes' business model and its existence relies heavily on continuing government and OEB support. We are fully expecting that Rural and Remote Rate Protection (RRRP) will continue for the plan period in its current form and that the RRRP variance account will be retained and cleared through cost of service proceedings. This is further supported by the government utilizing Remotes' unique ability to access RRRP to fund Watay transmission operating costs.

Since the 2018 Cost of Service, Remotes has generally followed both the OMA and Capital approved programs and has also successfully managed third party Customer Capital funding investments. For 2022, we will begin to see the impacts of the Watay grid project on RRRP.

The variance account is expected to be cleared in the next COS filing in 2023, which is expected to be $17.1M in 2022. This amount includes $4.5M that was not cleared during the 2018 COS due to the OEB's view on the treatment of pension costs. Beyond 2023, we will require increased RRRP funding to fully support Watay transmission costs.

Financial Analysis

Over the plan period, energy revenue remains flat as more customers are served, but are offset by the reduction in higher Standard "A" rates once grid connected. OMA also remains fairly flat as reduction in generation spending are offset by climbing distribution costs. Fuel costs are expected to drop, as usage dwindles offset in a similar fashion by cost of power increases as communities become grid connected. Capital programs, mainly driven by generation projects remain steady for the next three years, but drop off in 2025, as generation capital upgrades and replacement needs diminish.

The introduction of Watay transmission costs, beginning in 2022 and growing to $104M by the end of the planning period, significantly alter the financial structure and cost effectiveness of Remotes. The total cost per kWh, nearly doubles over the plan period as the Watay Tx costs are spread over our limited customer usage.

Financial Summary

Summary								
	Actual	**Forecast**	**Budget**			**Outlook**		
$K	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Revenue - Customer/Other	23,188	24,417	24,090	24,652	24,179	24,215	24,737	25,260
Subsidy	35,223	35,223	35,223	38,554	38,554	38,554	38,554	38,554
OM&A	(21,185)	(22,373)	(22,533)	(22,050)	(22,246)	(23,314)	(23,443)	(22,925)
Watay Transmission Costs	0	0	(21,285)	(66,000)	(103,695)	(103,695)	(103,695)	(103,695)
Cost of Power	(1,779)	(1,792)	(2,795)	(8,162)	(14,106)	(15,954)	(16,351)	(16,898)
Fuel	(29,166)	(33,699)	(32,461)	(23,356)	(12,720)	(10,648)	(10,812)	(10,971)
Other	(5,790)	(6,550)	(8,237)	(8,015)	(8,978)	(9,057)	(7,543)	(9,711)
Shortfall - RRRP	**491**	**(4,774)**	**(27,998)**	**(64,377)**	**(99,012)**	**(99,899)**	**(98,553)**	**(100,386)**
Capital Expenditures (gross)	13,150	13,361	15,592	15,723	13,050	5,595	5,837	5,054
Capital Expenditures (net)	3,750	5,544	8,789	10,591	7,648	3,332	3,532	2,702
Total Energy Revenue/kWh	0.27	0.28	0.28	0.24	0.21	0.20	0.21	0.21
Total Cost/kWh	0.67	0.75	0.99	1.21	1.37	1.35	1.33	1.34

Summary of Investments – OMA

OMA is generally consistent year over year with some increase in distribution work, offset by generation reductions as both new and old communities become grid connected.

Summary of Remotes OM&A Plan								
	Actual	**Forecast**	**Budget**			**Outlook**		
$K	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Common	717	1,667	1,459	1,541	1,700	1,754	1,785	1,886
Distribution Sustainment	3,634	4,140	3,910	4,759	5,000	5,491	6,142	5,195
Distribution Customer	1,524	1,276	1,449	1,535	1,548	1,565	1,592	1,616
Environment	888	1,108	1,182	1,196	1,216	1,238	1,256	1,278
Generation Sustainment	12,268	11,734	12,208	10,635	10,267	10,329	9,751	9,969
Generation Development	758	575	743	743	733	733	733	733
Other	1,396	1,873	1,582	1,641	1,782	2,204	2,184	2,248
OM&A	**21,185**	**22,373**	**22,533**	**22,050**	**22,246**	**23,314**	**23,443**	**22,925**

Common includes regulatory activities, community relations, customer outreach and program delivery, and the civil maintenance program for auxiliary buildings.

Distribution Sustainment includes on-going distribution sustainment activities such as forestry and maintenance, as well as trouble calls, generally increasing over time as our service territory expands. Maintenance on distribution assets is intended to ensure that the overall reliability of the distribution systems is maintained and improved, customer commitments are met, and all legislative and regulatory requirements are met.

Distribution Customer includes billing and customer account service generally increasing as the customer counts grows.

Environment includes health, safety and environmental support activities such as safety meeting material preparation, compliance assistance, waste management, training as well Environment, Health and Safety Management System (EHSMS) implementation, monitoring and audits necessary to ensure compliance, promote continuous improvement and maintain ISO 14001 registration.

Generation Sustainment includes engine and alternator maintenance, auxiliary and tank farm maintenance, in which the costs are slowly reducing over time as communities become grid connected offset by back-up power sustainment activities.

- Generator maintenance includes planned and unplanned costs. Planned maintenance of diesel generating units prevents premature equipment and system failures and contributes to service reliability. It includes all work performed on the diesel engine and associated alternator in accordance with standard maintenance procedures as prescribed by the original equipment manufacturer. Unplanned maintenance includes maintenance and repair of diesel generating units in response to trouble reports and equipment/component failures.
- Auxiliary maintenance includes, the main breaker cabinet, the station PLC, secondary heating, primary cooling, ventilation, pump controls, overhead crane inspections, station air compressors, DC batteries, station service electrical equipment and fire protection systems and all fuel system equipment and controls within the station.
- Tank farm maintenance includes regular inspections of all bulk fuel storage tanks, transfer pumps, control circuitry, piping and valves in the tank farm and the fuel delivery kiosk and metering units. This work helps prevent premature failures and ensures the tank farm remains in working condition throughout its asset life.

Generation Development includes on-going safety, environmental improvements as well as engineering investigation of contemporary operational issues and concerns. These programs decrease over time as more communities are grid connected.

Other includes mainly Corporate Functions & Services (CF&S) fees for support services received from other Hydro One entities.

2022 OMA Overview

The OMA program is generally consistent year over year and is consistent with the 2018 COS. There are no material changes in the 2022 budget as grid connection gains momentum in future years.

Summary of Investments – Capital

Total Capital has continued shorter term investment in core generation capital replacement and upgrades, transitioning into wholesale metering and back-up activities. Significant capital reductions are noted after grid connection starting 2025.

Summary of Remotes Capital Plan								
	Actual	Forecast	Budget			Outlook		
$K	2020	2021	2022	2023	2024	2025	2026	2027
Distribution Sustainment	177	532	349	548	601	400	406	411
Distribution Development	1,048	627	2,026	4,328	2,979	687	702	714
Distribution Customer	1,128	1,742	1,290	1,438	1,621	1,709	1,741	1,772
Facilities	11	901	887	1,952	437	447	454	462
Generation Sustainment	2,870	3,575	6,187	4,337	4,159	514	574	664
Generation Development	481	1,152	120	901	1,018	1,708	1,830	901
Generation Customer	7,298	4,702	4,603	2,089	2,105	0	0	0
Minor Fixed Assets	138	130	130	130	130	130	130	130
Total Capital, Gross	**13,151**	**13,361**	**15,592**	**15,723**	**13,050**	**5,595**	**5,837**	**5,054**
Contributed Capital, Removals	(9,401)	(7,817)	(6,803)	(5,132)	(5,402)	(2,263)	(2,305)	(2,352)
Total Capital, Net	**3,750**	**5,544**	**8,789**	**10,591**	**7,648**	**3,332**	**3,532**	**2,702**

Distribution Sustainment includes defective meter replacements, damage claims, service cancellations and small external demand requests. There is moderate program spending similar to existing, with occasional one-time variances for the addition of new communities and customer metering implementation.

Distribution Development involve replacing and/or refurbishing system assets to extend the service life of the assets and thereby maintain the ability of remotes' distribution system to provide customers with reliable electricity services at reasonable rate. This program has significant investments (ranging from $1.4M to $2.3M annually) in 2022 to 2024 related to wholesale metering cluster construction with the addition of new communities.

Distribution Customer includes new customer connections, service upgrades and fixed price layouts, all of which are initiated by customers and are all 100% recoverable from customers. This program has increasing new connection customer activity from the addition of new communities, expected government housing investments and school projects.

Facilities relates to staff housing improvements, TWE garages, storage buildings and other various civil projects with some investments made to the newly acquired communities.

Generation Sustainment are modifications to generation assets to ensure that the system continues to meet Remotes' operational objectives, while addressing anticipated future customer electricity requirements and includes engine replacements and overhauls, renewable energy technology, diesel plant civil improvements and back-up generation. This program has on-going generation investments including overhauls and replacements of gensets. 2022 and 2023 include Big Trout Lake A replacement, 2022 includes Deer Lake C unit replacement, 2024 includes Lansdowne C unit replacement and 2023 and 2024 includes Armstrong A, B and C units all of which are nearing end of life. Back-up power design for IPA sites added to the 2021-2024 period. The communities of Lansdowne and Armstrong are not connecting to the grid. Generation sustainment activities drop off significantly in 2025 as diesel energy production falls.

Generation Development includes SCADA upgrades and enhancements, leak detection and fuel system compliance work and improvements in the shorter term but drops off in future years.

Generation Customer has ISC fully funded upgrades including Webequie in 2022, Gull Bay Upgrade (Phase 3 execution) in 2022 to 2023, and Lansdowne in 2023 to 2024. All three communities noted are not part of the broader Watay project, so on-going diesel investments are required.

Minor Fixed Assets includes on-going tools and equipment requirements to support business activities.

2022 Capital Overview

We are starting the wholesale metering cluster construction work in 2022 relating to the Watay project. Customer connections are expected to continue to grow. Generation investments are being made to maintain reliability in leading up to grid-connection and customer driven upgrades are necessary in off-grid communities to allow for growth and ensure reliable service.

Included in the 2022 Capital Budget are the following capital projects that are greater than $500K:

2022 Budget - Capital Items (Gross) > $500K	
$K	**Budget 2022**
Distribution Development	
Distribution System Improvements	601
Wholesale Metering Construction	1,425
Distribution Customer	
New Cust Connections & Service Upgrades	997
Facilities	
Beaverhall Office Expansion	501
Generation Sustainment	
Engine Replacements	
Big Trout A Unit - Genset Replacement	4,381
Deer Lake C (Detroit)	1,102
Generation Customer	
Gull Bay Upgrade - Phase 3 Execution	1,002
Webequie 1.5 MW G1	3,551

Refer to Appendix A for the budgeted financial statements.

Staff Count

Staff Count	Actual 2020	Forecast 2021	Budget 2022	Outlook 2023	2024	2025	2026	2027
MCP	5	5	5	5	5	5	5	5
SOC	14	15	16	16	16	16	16	16
PWU - Main Trade	18	18	21	21	21	21	21	21
PWU - Weekly Salaried	18	18	19	21	22	22	22	22
Total Regular Staff	**55**	**56**	**61**	**63**	**64**	**64**	**64**	**64**

Remotes' work is performed by regular and hiring hall staff, services purchased from Hydro One Networks (including lines, forestry, health and safety, environment, engineering), contracts with external firms (engineering, environmental services) augmented by contracts with local communities for station operators, meter readers, as well as, casual resources related to land assessment and remediation, construction and CDM projects.

Full-time regular staff perform on-going trades, supervisory and administrative functions in a variety of capacities and departments. Hiring Hall staff are mainly used for larger capital construction projects and seasonal work. Remotes also routinely trains and mentors various trade apprentices, exposing them to a variety of challenging and unique work experiences.

More resources are required in P&C, Lines, Engineering and Billing/Customer Care areas over the plan period on an either a temporary or permanent basis as customer numbers increase, stakeholder expectations continue to grow, and greater complexity is introduced with operations in both the on and off-grid environments.

Performance Objectives

Performance objectives in 2022 reflect the strategies undertaken throughout the plan period. Maintaining a strong Safety focus will be required to ensure our Safety target of zero serious injuries is met. We will leverage the EHSMS to drive continuous improvement in all aspects of HSE performance. We will continue to track initiatives developed within the EHSMS to serve as a proactive measure of commitment to HSE improvements. Customer outreach initiatives are determined annually by the Management team based on customer survey results, customer advisory board input, conservation goals, community leadership and tribal council feedback, and staff suggestions to improve customer relationships. Remotes will continue to focus on improving reliability by measuring SAIDI, SAIFI and generation availability for its off-grid communities. Productivity measures will continue to highlight the importance of detailed design, stage-gate readiness and efficient execution of major projects. As well, Remotes will continue with its on-going commitment to no major spill events while managing operational spill risk. Overall, the 2022 performance objectives will be similar to 2021, as our core values and strategy remains unchanged.

2022 Scorecard – DRAFT

Strategic Objective		Performance Measure	Year to Date		Status	Year End	
			Actual	Target	YTD	Target	Forecast
Health & Safety	Create an Injury Free Workplace	Serious Injuries				0	
		Recordable Incidents				1	
		Near Miss/Safety Catches				TBD	
		HSMS Objectives and Achievements				Number of planned initiatives	
Customer Relations	Inspire Customer Loyalty and be a Trusted Partner	Customer & Community Outreach Initiatives				Number of planned initiatives	
Operational Excellence	Maintain/Improve System Reliability	System Duration of Total Interruptions (SAIDI) Hours of interruption per delivery point				TBD	3-year average
		System Frequency of Total Interruptions (SAIFI) Interruptions per delivery point				TBD	3-year average
		Generation Availability				99.5%	
Productivity	Improve Efficiency of Operations	Design & Planning				Project milestones	
		On time, on budget project milestones				TBD	
Environmental Stewardship	Protect the Environment for Future Generations	Litres lost to the Environment				100	
		Hydro One Spills				TBD	
		Significant Spills over 100L				0	
		EMS Objectives and Achievements				Number of planned initiatives	

▲ Below Threshold ■ Below Target ● Target ★ Exceeds

Appendix A: Remotes Budgeted Financial Statements 2022-2027

Statement of Operations	**2022 BUSINESS PLAN**							
	Actual	**Projection**	**Budget**			**Outlook**		
in $K	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Revenues	57,920	64,414	87,311	127,583	161,745	162,668	161,844	164,200
Energy - Off Grid	*20,339*	*21,114*	*20,464*	*15,663*	*8,877*	*6,718*	*6,817*	*6,917*
Energy - Grid	*1,835*	*1,990*	*2,715*	*8,074*	*14,347*	*16,522*	*16,943*	*17,365*
Subsidy	*35,223*	*35,223*	*35,223*	*38,554*	*38,554*	*38,554*	*38,554*	*38,554*
RRRP Variance	*(491)*	*4,774*	*27,998*	*64,377*	*99,012*	*99,899*	*98,553*	*100,386*
External	*1,014*	*1,313*	*911*	*915*	*955*	*975*	*977*	*978*
Costs								
OM&A	21,185	22,373	22,533	22,050	22,246	23,314	23,443	22,925
Distribution Sustainment	*3,634*	*4,140*	*3,910*	*4,759*	*5,000*	*5,491*	*6,142*	*5,195*
Distribution Customer	*1,524*	*1,276*	*1,449*	*1,535*	*1,548*	*1,565*	*1,592*	*1,616*
Generation Sustainment	*11,849*	*11,330*	*11,808*	*10,127*	*9,759*	*9,821*	*9,343*	*9,561*
Generation Development	*758*	*575*	*743*	*743*	*733*	*733*	*733*	*733*
DCAM Sustainment	*419*	*404*	*400*	*508*	*508*	*508*	*408*	*408*
Environment	*888*	*1,108*	*1,182*	*1,196*	*1,216*	*1,238*	*1,256*	*1,278*
Common	*717*	*1,667*	*1,459*	*1,541*	*1,700*	*1,754*	*1,785*	*1,886*
Other	*1,396*	*1,873*	*1,582*	*1,641*	*1,782*	*2,204*	*2,184*	*2,248*
Cost of power	1,779	1,792	2,795	8,162	14,106	15,954	16,351	16,898
Watay Transmission costs	0	0	21,285	66,000	103,695	103,695	103,695	103,695
Fuel used for electric generation	29,166	33,699	32,461	23,356	12,720	10,648	10,812	10,971
Depreciation and Amortization	4,065	4,616	6,005	5,640	6,766	6,981	5,762	7,911
LAR amortization	*870*	*1,332*	*2,606*	*1,883*	*2,503*	*2,593*	*1,037*	*3,028*
Depreciation	*2,834*	*2,990*	*3,052*	*3,430*	*3,745*	*4,160*	*4,489*	*4,634*
Asset removal costs	*361*	*294*	*347*	*327*	*518*	*228*	*236*	*249*
Financing charges	1,814	1,934	2,232	2,375	2,212	2,076	1,781	1,800
Loss on Disposal of Assets	(86)	0	0	0	0	0	0	0
Total Costs	57,923	64,414	87,311	127,583	161,745	162,668	161,844	164,200
Income before income taxes	**(3)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Income tax expense	(3)	0	0	0	0	0	0	0
Net loss	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Other comprehensive income	18	18	21	22	23	25	26	27
Comprehensive income	**18**	**18**	**21**	**22**	**23**	**25**	**26**	**27**

Balance Sheet	2022 BUSINESS PLAN							
	Actual	Projection	Budget			Outlook		
in $K	2020	2021	2022	2023	2024	2025	2026	2027
Assets								
Current assets:								
Inter-company demand facility	-	-	-	121	2,375	7,850	4,716	758
Accounts receivable	8,342	6,461	6,045	6,503	6,470	6,465	6,518	6,567
Fuel, materials and supplies	2,535	2,903	2,702	2,012	1,722	1,772	1,822	1,872
Income taxes receivable	20	-	-	-	-	-	-	-
	10,897	9,364	8,747	8,636	10,567	16,087	13,056	9,197
Property, plant and equipment	49,816	52,315	58,287	65,683	69,517	68,928	68,211	66,521
Other assets:								
Environmental regulatory asset	43,379	44,843	42,237	40,354	37,850	35,257	34,220	31,192
RRRP receivable	5,598	10,372	17,085	5,091	408	-	-	-
Other regulatory assets	1,156	830	786	744	686	627	565	497
Deferred income tax assets	4,493	4,480	4,467	4,454	4,441	4,428	4,415	4,402
Other assets	220	151	190	171	152	132	114	100
	54,846	60,676	64,765	50,814	43,537	40,444	39,314	36,191
Total assets	**115,559**	**122,355**	**131,799**	**125,133**	**123,621**	**125,459**	**120,581**	**111,909**
Liabilities								
Current liabilities:								
Inter-company demand facility	42	4,586	5,969	-	-	-	-	-
Accounts payable and accrued liabilities	9,394	9,286	8,316	9,224	9,363	7,864	9,944	9,956
Accrued interest	280	265	376	376	376	376	278	167
Long-term debt	-	-	-	-	-	10,000	10,000	-
	9,716	14,137	14,661	9,600	9,739	18,240	20,222	10,123
Long-term liabilities:								
Long-term debt	43,049	42,948	52,920	52,928	52,935	42,944	32,952	32,958
Post-retirement and post-employment benefit liability	17,898	18,647	19,470	20,352	21,277	22,242	23,248	24,295
RRRP payable	-	-	-	-	-	3,388	8,530	11,838
Regulatory liabilities	4,493	4,480	4,467	4,454	4,441	4,428	4,414	4,402
Environmental liabilities	40,515	42,237	40,354	37,850	35,257	34,220	31,192	28,243
	105,955	108,312	117,211	115,584	113,910	107,222	100,336	101,736
Shareholder's equity (deficit)								
Common shares	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Deficit	(4,651)	(4,651)	(4,651)	(4,651)	(4,651)	(4,651)	(4,651)	(4,651)
Accumulated other comprehensive loss	(461)	(443)	(422)	(400)	(377)	(352)	(326)	(299)
	(112)	(94)	(73)	(51)	(28)	(3)	23	50
	115,559	**122,355**	**131,799**	**125,133**	**123,621**	**125,459**	**120,581**	**111,909**

Statements of Cash Flows	2022 BUSINESS PLAN							
	Actual	Projection	Budget			Outlook		
in $K	2020	2021	2022	2023	2024	2025	2026	2027
Operating activities								
Net income (loss)	-	-	-	-	-	-	-	-
Environmental expenditures	(870)	(1,332)	(2,606)	(1,883)	(2,503)	(2,593)	(1,037)	(3,028)
Adjustments for non-cash items:								
Depreciation and amortization	3,704	4,322	5,658	5,313	6,248	6,753	5,526	7,663
Regulatory assets and liabilities	312	(5,913)	(4,063)	13,920	7,244	3,060	1,099	3,096
Other	27	2,494	(1,361)	(1,831)	(1,572)	3,106	2,904	1,186
Changes in non-cash balances related to operations	(5,650)	1,412	(242)	1,139	462	8,456	1,879	(10,199)
Net cash from (used in) operating activities	(2,477)	983	(2,614)	16,658	9,879	18,782	10,371	(1,282)
Financing activities								
Issuance of long-term debt	-	-	10,000	-	-	-	-	-
Repayment of long-term debt	-	-	-	-	-	(10,000)	(10,000)	-
Other	-	18	21	22	23	25	26	27
Net cash from financing activities	-	18	10,021	22	23	(9,975)	(9,974)	27
Investing activities								
Capital expenditures and future use assets	(4,006)	(5,545)	(8,790)	(10,590)	(7,648)	(3,332)	(3,531)	(2,703)
Net cash used in investing activities	(4,006)	(5,545)	(8,790)	(10,590)	(7,648)	(3,332)	(3,531)	(2,703)
Net change in inter-company demand facility	(6,483)	(4,544)	(1,383)	6,090	2,254	5,475	(3,134)	(3,958)
Inter-company demand facility, beginning of year	6,441	(42)	(4,586)	(5,969)	121	2,375	7,850	4,716
Inter-company demand facility, end of year	**(42)**	**(4,586)**	**(5,969)**	**121**	**2,375**	**7,850**	**4,716**	**758**

Material Investment Narrative

Watay Grid Connection 4-Pole Cluster

INVESTMENT SUMMARY	
Main Driver:	**Third Party Infrastructure Development Requirements (Watay Project)**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness, Public Policy Responsiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	3,644	2,263	0	0	0

Summary:

This investment involves the design and construction for 4-pole distribution clusters in each of the 16 communities being connected to the Watay Project. This investment is required to allow the connection of the communities to the provincial electricity grid.

The investment is expected to serve as the demarcation point for the Remotes and Wataay grid connection in each of the connected communities and will also serve as the IESO metering point as required under the Transmission System Code.

A. General Information on the Project/Program

1. Overview

The Wataynikaneyap grid connection project (Watay Project) is a generational project that will revolutionize energy in Northern Ontario. The Watay Project corresponds to the construction of a transmission line that will connect 16 remote First Nation communities in Northern Ontario to the Ontario Power Grid. Over the plan period, Remotes will see growth in its service territory and will transition to a Transmission connected distributor while continuing to offer off-grid generation and distribution services.

Remotes is requesting the approval of $7.407M for the purchase of materials, design, and construction costs for a 4-pole cluster in each of the communities being connected to the Wataay Project. The 4-pole cluster is a collection of individual pole designs required at each location. The common design elements of the 4-pole cluster, shown in Figure 1 below, includes a tension change dead-end, wholesale revenue metering, G&W Electric Viper recloser, and load break disconnect pole. SCADA (supervisory control and data acquisition) and communication components will also be included, unique to requirements of each community.

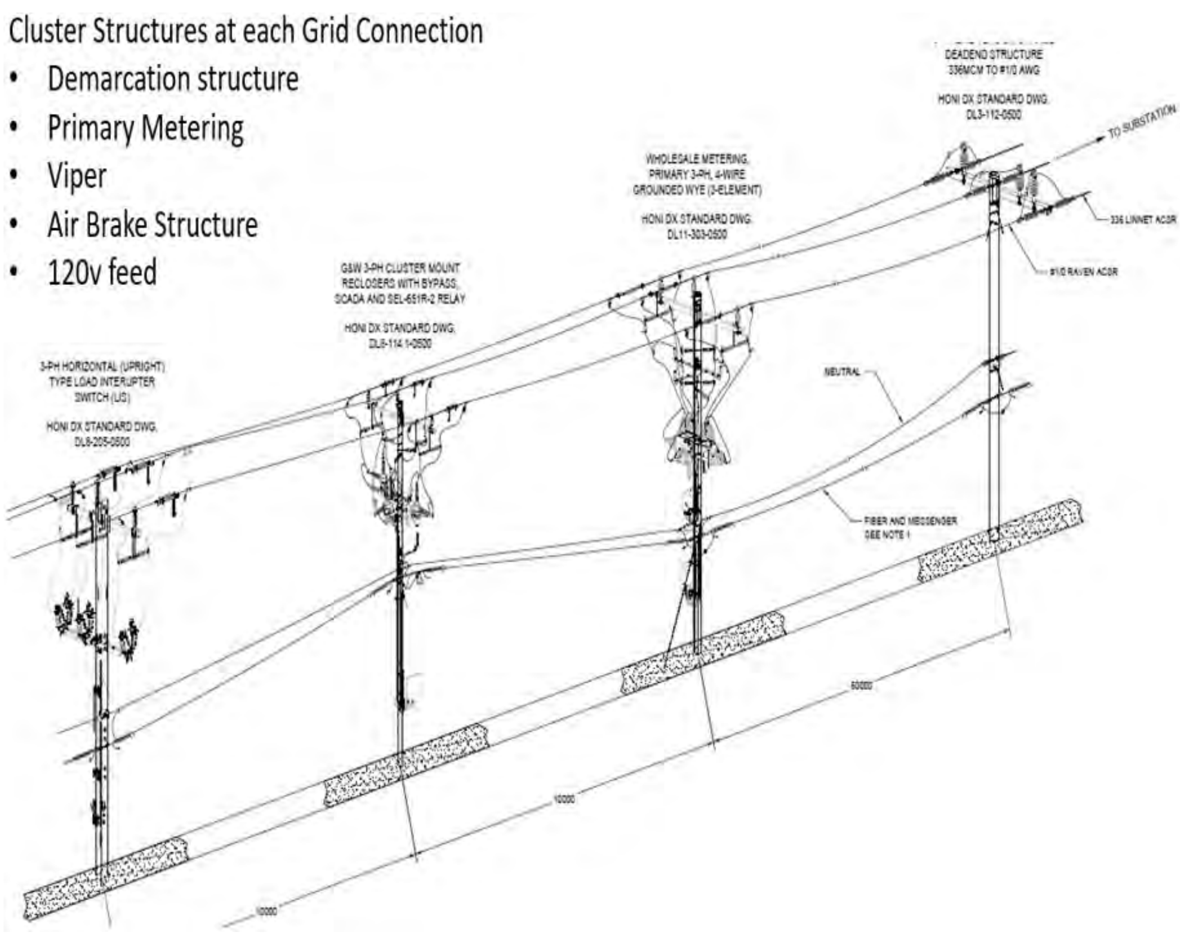


***Figure 1**: 4-Pole Cluster Design.*

The 4-pole cluster will include the demarcation point for the Remotes / Wataynikaneyap Power LP (Watay) grid connection to each community. In addition, this structure will serve as the Independent Electricity System Operator (IESO) metering point as required under the transmission code and is necessary for grid connection compliance. The initial design work for this project was completed in 2021 for $106,000.

This is a multi-year project that will be executed based on the scheduled grid connection to the communities, with most of the work being done a few months prior to grid connection. The structures will be placed into service on grid connection day. The planned community connection dates and associated project costs are summarized in Table 1.

***Table 1**: Scheduled Grid Connections and Costs*

In-Service Date[1]	Cost ($'000)	Communities Connected
2022	$1,394	Pikangikum, Weagamow, Kingfisher
2023	$3,644	Muskrat Dam, Sachigo, Bearskin, Wawakepewin, Wunnumin, Wapekeka, Big Trout, Kasabonika
2024	$2,263	Poplar Hill, Deer Lake, North Spirit, Sandy Lake, Keewaywin

[1] The in-service date shown is based on the October 2021 version of the Watay Project schedule.

This project is required to ensure community readiness and a smooth transition to regulated service and connection to the Ontario Power Grid.

2. TIMING

i. *Start Date:* January 2022, with varying starting dates by community

ii. *In-Service Date*: March 2024, with varying in-service dates by community

iii. *Key factors that may affect timing:* The timing of this project is highly dependent on the execution timing of the Watay Project and the scheduled grid connections to the communities, which is a function of the readiness of the transmission line and distribution stations at each community connection point. Other factors that may affect timing include IPA readiness, regulatory approvals, construction needs, resource availability and COVID-related delays.

3. HISTORICAL AND FORECAST CAPITAL EXPENDITURES

***Table 2**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	106	1,394	3,644	2,263	0	0	0	7,407
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	106	1,394	3,644	2,263	0	0	0	7,407

The costs are non-recoverable and are paid by the distributor/customer under the current regulatory framework.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The 4-pole cluster is a collection of individual pole designs required at each location. The project costs comprise design, material, construction, contractor, and overhead costs required within each community. Mobilization and demobilization cover a significant portion of the costs. Similar individual pole designs have been used by Remotes in the past, but this is the first time that Remotes is using them in a clustered manner.

6. Investment Priority

This is a high priority investment. Without this investment, multiple remote communities will not be able to connect to the Watay Project and the provincial grid, which will hinder the completion of the project and community access to reliable electricity.

7. Alternatives Analysis

No alternatives were considered. This investment is non-discretionary. Revenue metering is critical to ensure reliable and accurate billing in accordance with regulatory requirements.

8. Innovative Nature of the Project

The 4-pole cluster is a collection of structures that all have standard designs. However, clustering the structures together in series, placed as close to each other as possible, is unique for Remotes as it is the first time that this 4-pole cluster is used. This design will ensure a safe and reliable connection to the provincial grid that is compliant with all regulated service connection requirements.

8. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 3: *Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Connection to the provincial grid will alleviate the potential for connection restrictions as the electrical capacity of the grid components will be much higher than the existing capacity of the diesel generating stations (DGS). In addition, the existing DGS within the grid-connected communities will be used as backup power only, and as a result, Remotes expects less callouts for unexpected maintenance response which will

Primary Criteria for Evaluating Investments	Investment Alignment
	result in improved operational efficiency and allow staff to be redeployed to other critical maintenance and capital project tasks.
Customer Value	This investment will connect 16 communities to the provincial grid. With this, these communities will have access to reliable electricity supply and there will be an increased ability to add new housing and other infrastructure to support community growth and development. Being connected to the grid will also reduce the level of diesel emissions within these communities.
Reliability	DGS have a limited capacity that must be increased periodically to satisfy increasing demand in communities. The capacity increase does not always occur in a timely manner and new connections might be restricted to maintain reliability for existing customers. With the Watay Project, these restrictions will be eliminated within the grid-connected communities. Additionally, Remotes will continue to provide backup generation in most grid-connected communities and maintain the 25kV distribution lines to ensure the communities have continued access to reliable electricity during any future outage events on the new Watay transmission grid.
Safety	Due to this investment, Remotes' existing DGS will no longer be running near their rated capacity and therefore will have less chance of catastrophic failures that could pose a safety or fire risk. In addition, the 4-pole structures demarcation points which will improve worker safety and provide faster emergency responses.

2. INVESTMENT NEED

The Watay Project is a major development in many communities in Remotes' service territory. Sixteen communities will be connected to the provincial grid and be able to access reliable electricity supply for community growth and development.

i. *Main Driver*: Third Party Infrastructure Development Requirements (Watay Project) – The main driver for this project is the development of the Watay Project and the associated need for infrastructure to connect the 16 communities to the provincial grid. Remotes has an obligation to Watay and the communities to facilitate these interconnections. The need for connection to the Watay Project has also been identified by community leadership as essential for their growth and development, and the 16 communities that will get access to the provincial grid are Watay Project partners as well.

ii. *Secondary Drivers*: Mandated Service Obligations - The investment is expected to serve as the demarcation point for the Remotes and Watay grid connection in each of the connected communities and will also serve as the IESO metering point as required under the Transmission System Code. Revenue metering is critical to ensure reliable and accurate billing in accordance with regulatory requirements.

iii. *Information Used to Justify the Investment*: The need for this investment was identified through ongoing consultations with Wataay and the community members and leadership. A reliable connection to the provincial grid and the increased capacity will help promote growth and development in the remote communities, while also reducing the level of diesel emissions within these communities. Revenue metering is also critical to ensure reliable and accurate billing in accordance with regulatory requirements.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: Remotes is in contact with Wataay, its contractor, Indigenous community leaders and their advisors through regular meetings to ensure the purpose and goals of the project are in alignment. Remotes is also ensuring that the wholesale revenue metering will be registered with the IESO and installed per the IESO Market Rules. Remotes will also ensure that the 4-pole clusters are constructed in accordance with Remotes practices and *O. Reg 22/04* requirements.

ii. *Cost-Benefit Analysis:* The proposed project is required to connect the 16 communities to the provincial grid. No alternatives were identified.

iii. *Historical Investments & Outcomes Observed:* Remotes has successfully undertaken standard pole design and construction projects in the past that have accommodated new customer connections to their distribution system. Similar design principles are being used as part of the 4-pole cluster.

iv. *Substantially Exceeding Materiality Threshold:* The Wataay Project is a major development in many communities in Remotes' service territory. This project is required to accommodate the interconnection of 16 remote communities to the provincial grid. The justifications for this project are included within this material investment narrative.

4. Conservation and Demand Management

CDM is not applicable for this project.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis*: This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

This project uses the same order of structures placed as close to each other as possible in a series in every community that Remotes is connecting. This design will ensure a safe and reliable connection of communities to the provincial grid that is compliant with all regulated service connection requirements.

Material Investment Narrative

New Customer Connections and Service Upgrades

INVESTMENT SUMMARY

Main Driver:	**Customer Service Requests**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness, Public Policy Responsiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Cost	0	0	0	0	0

Summary:

This investment involves the connection of new load customers to the Remotes' distribution system and the upgrade of service for existing load customers as required. New connections and service upgrades are customer-funded and are entirely recoverable. The main driver for this investment is customer-initiated requests.

The investment is expected to meet Remotes' requirements to connect new services and to upgrade existing services in compliance with distribution regulatory and licence obligations.

A. General Information on the Project/Program

1. Overview

Remotes currently serves 22 communities across Northern Ontario, among which 17 are First Nation communities. Cat Lake and six new IPA communities are anticipated to join Remotes' distribution system in 2023 and 2024. To support the growth and development of these communities, Remotes routinely accommodates new customer connections and service upgrades.

Capital projects included under this program are customer-initiated requests for connection to Remotes' distribution system and/or expansion of distribution assets to accommodate such requests. New customer connections vary from year to year and may include provision/expansion of distribution lines, transformers, switches, fuses, meters, and electrical termination facilities. New connections and service upgrades are planned using standardized designs that meet the requirements of *O. Reg. 22/04*, made under the *Electricity Act, 1998*. Remotes manages the engineering and design costs of these projects, while providing consistent design quality throughout its service territory. Investments in this program are initiated by customers and project costs are 100% recoverable and any cost savings are directly passed on to the customers. The forecast costs under this program are informed by historical trends, considerations of growth and development and the connection of new communities.

New customer connections and service upgrades allow customers to connect to Remotes' distribution system in their community and have vital access to electricity. Connecting new customers to the system also fosters growth and development within the community.

2. Timing

i. *Start Date:* January 2023, with customer connects varying on start date

ii. *In-Service Date:* December 2027, with customer connects varying on in-service date

iii. *Key factors that may affect timing*: Year-over-year fluctuations in the volume of work performed under this program vary based on the number of customer requests received each year. The timing of work depends on when the customer request is made. Most connections are completed in the same year as the customer request, however some carry-over until the following year.

3. Historical and Forecast Capital Expenditures

***Table 1**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($'000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	775	1,248	783	1,340	997	1,113	1,255	1,322	1,346	1,371
Contributions	(741)	(1,212)	(770)	(1,297)	(997)	(1,113)	(1,255)	(1,322)	(1,346)	(1,371)
Removals	(16)	(27)	(10)	(9)	0	0	0	0	0	0
Capital (Net)	18	9	3	34	0	0	0	0	0	0

New connections and service upgrades are customer-funded and 100% recoverable. Remotes manages the engineering and design costs of these projects.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The number of forecast connections and service upgrades required fluctuates each year depending on the number of requests made by customers, and the scopes of work vary based on the size, nature, and volume of activities required to accommodate the requests. Expenditures under this program are forecast based on historical trends, considerations of growth and development within the communities, and the addition of Cat Lake and the six new IPA communities in 2023 and 2024. The number of customer connections is also influenced by federal Indigenous housing programs and initiatives.

6. Investment Priority

This is a non-discretionary program driven by customer service requests and the costs are fully recoverable. When customer connection and service upgrade requests are initiated, they will take priority over other system undertakings and plans.

7. Alternatives Analysis

No alternatives are considered. This work is a regulatory requirement. Not proceeding with customer-initiated requests would result in non-compliance with Remotes' obligations under its distribution license requirements and the Distribution System Code.

8. Innovative Nature of the Project

There is nothing inherently innovative to Remotes about this program.

9. Leave to Construct Approval

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 2**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Remotes manages the engineering and design costs of these projects through standardized designs, while providing consistent and efficient design quality throughout its service territory. When the scope of the project includes the replacement of distribution transformer(s), newly procured transformer units will meet the latest standards in energy efficiency. Remotes also attempts to coordinate new

Primary Criteria for Evaluating Investments	Investment Alignment
	connections and/or service upgrades where possible to optimize efficiency and cost effectiveness by combining work into a single trip.
Customer Value	The main benefit to customers is connection to the electrical system and having access to reliable electricity. In addition, connecting new customers to the system encourages economic growth and development in the respective communities. Enabling customer requests for connection within established timeframes will also help ensure customer satisfaction.
Reliability	Connecting new customers has impacts on system capacity. To circumvent this, Remotes accounts for this impact during its planning phase and works closely with the communities it serves to ensure adequate system capacity is in place to serve their immediate and future needs.
Safety	All new construction conforms to the latest standards for health and safety protections and performance. New smart meters installed under this program as part of the customer connection or service upgrade also meet the latest cyber-security standards.

2. Investment Need

This program is driven by customer service requests. The changing population and more intensive use of electricity in remote communities has increased the overall number of new connections for Remotes in recent years and is expected to continue growing. This plan also anticipates the addition of Cat Lake and six new communities currently serviced by an IPA in 2023 and 2024. It is imperative for Remotes to accommodate these requests in order to maintain customer satisfaction and facilitate the growth and development of remote communities in northern Ontario by providing access to reliable electricity supply.

i. *Main Driver*: Customer Service Requests - Projects within the program are driven by customer service requests. This work is non-discretionary, and the scopes and timelines are based on requirements from the customers requesting the services.

ii. *Secondary Drivers*: There are no secondary drivers associated with this program.

iii. *Information Used to Justify the Investment*: The projects undertaken in the program are based on customer requests. The number of customer connections and service upgrades are forecast based on historical trends, considerations of growth and development within the communities, and the addition of Cat Lake and the six new communities currently serviced by an IPA in 2023 and 2024. Remotes also consults with customers and communities on a regular basis to remain informed on their connection needs and expectations for growth and development within the communities.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: New connections and service upgrades are planned using standardized designs that meet the requirements of *O. Reg. 22/04*. In doing so, Remotes manages the engineering and design costs of these projects, while providing consistent design quality throughout its service territory. Customers also follow a standardized connection process by calling Remotes customer service department. At a high level, the process includes requesting service, designing the layout, and setting up an account. Once the Electrical Safety Authority (ESA) has inspected the premises, connection and construction work takes place after payment is received.

ii. *Cost-Benefit Analysis:* Alternative methods of new customer connections and service upgrades come with ownership and maintenance issues, which will hinder Remotes' ability to manage costs and maintain electrical reliability for customers. Investment in projects under this program follow standardized designs to allow access to affordable and reliable power supply to both new and existing customers.

iii. *Historical Investments & Outcomes Observed:* Remotes routinely provides new connections and service upgrades to remote communities. These investments have allowed continued growth and development within the communities which benefited residents. They also allowed Remotes to ensure dependable generation and reliability for existing customers.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this program are included within this material investment narrative.

4. Conservation and Demand Management

CDM is not applicable for new customer connections and service upgrades.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis*: This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

There is nothing inherently innovative to Remotes about this program.

Material Investment Narrative

Armstrong A & B Unit Generator Replacements

INVESTMENT SUMMARY

Main Driver:	**Failure Risk**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	1,270	1,154	0	0	0

Summary:

This investment involves the replacement of the Armstrong A and B generation units which supply electricity to over 365 customers across three communities. The communities served by Armstrong A and B will not be grid-connected by the Watay Transmission project and will therefore continue to rely on diesel-generated electricity. The two generator units have reached the 60,000-hour engine operating threshold and are also in poor condition. The investment also replaces the master control system for the generators at Armstrong DGS. The existing master control system is not compatible with the engine control systems being installed with the two replacement generators and is also obsolete and no longer supported by the manufacturer.

The investment is expected to ensure the continued delivery of safe and reliable prime-power generation in Armstrong, with Armstrong DGS as the only source of electricity for the communities for years to come.

A. General Information on the Project/Program

1. Overview

The Armstrong diesel generation station (DGS) was originally built in the late 1990's and currently consists of 3 diesel generators: Armstrong A, B and C. The plant currently supplies electricity to over 365 customers in the communities of Armstrong, Collins and Whitesand First Nation (Collins and Whitesand are served via the Armstrong distribution system). These communities will not be grid-connected when the Watay Transmission Project comes online, and as a result, these units are critical and are required to supply electricity to the communities for years to come. The engine size, speed, vintage, condition and current and forecast engine hours are summarized in the Table 1.

***Table 1:** Engine Condition of Generators in Armstrong Diesel Generation Station*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition [2]	Engine Hours[3]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Armstrong A	725	1,800	2018	Poor	77,766	80,904	84,045	87,185	90,325	93,466
Armstrong B	725	1,800	2011	Poor	62,262	65,609	68,957	72,302	75,561	78,998
Armstrong C	1,100	1,800	1999	Poor	51,436	53,486	56,035	58,583	61,131	63,679

[1] In-service year normally corresponds to the year the unit was installed. In the case of the Armstrong units, this corresponds to the year the engine block was changed. For the Armstrong A and B units, although the block was changed in 2018 and 2011 respectively, the other components on the units were put in service in 1999.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The engine condition is current as of February 2022.
[3] Engine-hours shown are current as of February 8, 2022.

The manufacturer's published recommendations for medium-speed generators (1,800 rpm) include complete overhauls after 20,000 hours, and Remotes has a policy that generators of this type shall be replaced once they reach the threshold for a third overhaul, generally at about 60,000 engine-hours. In addition, the units are inspected and maintained every 2,500 hours to determine the condition. Based on this, Remotes is proposing to implement two generator replacements over the forecast period:

- **Armstrong A:** The Armstrong A unit is in poor condition and is beyond the 60,000 engine-hour threshold that triggers replacement. An identical like-for-like replacement is not possible due to the late-1990's vintage of the unit, however the replacement unit will have a similar capacity and speed. The engine replacement will also require a new radiator, aftercooler, and exhaust system. Pictures of the unit are included in Attachment 1.

- **Armstrong B:** The Armstrong B unit is in poor condition and is beyond the 60,000 operating hour threshold that triggers replacement. An identical like-for-like replacement is not possible due to the late-1990's vintage of the unit, however the replacement unit will have a similar capacity and speed. The engine replacement will also require a new radiator, aftercooler, and exhaust system.

Although the Armstrong C unit is approaching end of life, Remotes is considering running the unit beyond the normal replacement timelines knowing that the other two newer units will operate the majority of hours and provide an added level of reliability. Ongoing consideration is being made to replace the C unit with an alternate sized unit, but Remotes is hoping to hold off until the Armstrong area load/economy balances and further integration and optimization into the potential biomass project can be explored.

In addition to the planned unit A and B replacements, the existing control system in the Armstrong DGS is obsolete, is no longer supported by the manufacturer and is not compatible with the newer engine control systems being installed with the replacement units. As a result, a new master control will be installed at the DGS and the Armstrong C unit will be upgraded to the newer controls as part of this project.

Remotes plans to invest $2.424M in 2023 and 2024 to complete the necessary work at the Armstrong DGS. Remotes decided to complete both engine replacements and control system upgrades simultaneously to enable time and cost efficiencies. This project is necessary to ensure continued delivery of safe and reliable electricity to the communities. A breakdown of the costs is as follows.

Table 2: *Cost Breakdown of the Project*

Cost Breakdown	Cost ($ '000)
Generators and Controls	1,451
Radiators, Exhausts, Piping, Miscellaneous Materials	300
Installation	500
Design	135
Fleet/TWE	38
TOTAL	**2,424**

2. TIMING

i. Start Date: March 2023

ii. In-Service Date: November 2024

iii. Key factors that may affect timing: A delay in receiving the necessary materials and equipment, especially long lead items, could delay the project by up to a year. The availability of resources needed to complete the project can also impact timing.

3. Historical and Forecast Capital Expenditures

Table 3: *Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	0	1,270	1,154	0	0	0	2,424
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	1,270	1,154	0	0	0	2,424

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Typical generator replacements will require a new radiator, a complete aftercooler piping circuit, an upgraded exhaust system, and electrical control and power upgrades. However, this project is more involved than a typical generator replacement. The need for upgraded controls on the C unit and an upgraded master control is beyond the scope of a normal replacement project. Therefore, this project will be more costly.

This project is expected to cost $2.424M. In order to compare the cost to other similar generator replacement projects, cost per kW can be considered. The new 1,800 rpm units will each have a capacity of 725 kW (1,450 kW in aggregate), rendering the cost per kW at $1,672.

A similar generator replacement was completed at Deer Lake in 2016, where a new 1,200 rpm generator unit with capacity of 1,500 kW was installed at the total cost of $1.75M, and per-kW cost of $1,166. The observed cost differences can mostly be attributed to the difference in generator speed and the additional cost associated with the upgrade of the station controls and C unit controls as part of the Armstrong project.

6. Investment Priority

This is a high priority project as it is integral in maintaining reliable prime-power generation in Armstrong which is not being grid-connected. This DGS will be the only source of electricity for the communities for years to come.

7. Alternatives Analysis

Remotes has considered the following options:

- Option 1: Do Nothing – This is not a viable alternative as it would jeopardize the electricity supply to the communities.
- Option 2 – Rebuild Engine – Both the A and B units have already been overhauled twice, and the A unit is operating beyond the recommended replacement threshold. Additionally,

fuel pumps are no longer available to rebuild these units so they cannot be rebuilt. As a result, this is not a viable option.

- Option 3 – Replace Engines & Upgrade Controls (Selected Option) – Remotes' extensive experience with generators provides knowledge that after a third overhaul, engines are inherently less reliable and no longer perform satisfactorily. They have more wear on the block and crankshaft (parts that are not replaced during an overhaul) that will cause oil leaks, coolant leaks, and other issues that will require increased maintenance effort and costs. As these generators are critical sources of electricity for these remote communities, it is imperative to ensure these generators continue to function safely and reliability, and therefore Remotes has identified an engine replacement as the only viable option. To support the new units, a new master control will also be installed at the DGS and the Armstrong C unit will be upgraded to the newer controls as part of this project. Replacing the generators will likely have a small incremental benefit on both fuel usage and emissions as technology has continued to improve.

- Option 4 – Replace Engines & Keep Existing Controls – Since the existing control system in the Armstrong DGS is obsolete, is no longer supported by the manufacturer and is not compatible with the newer engine control systems being installed with the replacement units, this is not a viable option.

8. Innovative Nature of the Project

Engine replacements are routine in nature and not innovative for Remotes. However, the control upgrade is not customary and will require extra effort. The new engines will also be compliant with the latest standards.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 4:** Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Newer units offer improved efficiency relative to the vintage units they replace. The new units will reduce maintenance costs in the near term. This in turn allows Remotes to direct staff to other critical maintenance and capital projects.
Customer Value	Installation of a newer, more reliable unit allows Remotes to continue providing a reliable source of electricity supply to the community. There is also added benefit from the reduced maintenance costs.
Reliability	Reliability of the new unit will be better relative to the existing unit that has been rebuilt multiple times. Old engines are also more prone to catastrophic failures which, besides being a

Primary Criteria for Evaluating Investments	Investment Alignment
	safety and fire risk, would affect reliability for months until a permanent replacement unit could be installed.
Safety	New units are inherently safer than old, nearly worn-out units. There are less chances for failures and leaks which could cause safety and fire issues. The new control system will also comply with the latest cyber-security standards.

2. Investment Need

i. *Main Driver*: Failure Risk – The Armstrong A and B units are on their second engine rebuild and have surpassed the 60,000 operating hour threshold and are therefore more prone to failure. A failure of either of these units would significantly impact Remotes' customers who rely on these units as their only source of electricity.

ii. *Secondary Drivers:* It is Remotes' policy, based on manufacturer's information and past experience, to replace generators when the engine requires a third overhaul. This is the case with this unit, as it has already had two engine rebuilds. New engines are also more fuel efficient and produce less air pollutants.

iii. *Information Used to Justify the Investment*: For the last 10 years, Remotes' generator policy has been used to help guide unit replacements. The policy is based on extensive maintenance and operating experience, consultation with other off-grid utilities, and manufacturer's recommendations. This policy is also a fundamental element of Remotes' AM process for diesel generators. Additional information on manufacturer recommendations and Remotes generator policy is included below, and further information on Remotes' generation AM process can be found in Section 5.3 of the DSP.

Manufacturer's Recommended Overhaul Interval

Figure 1 highlights a representative maintenance overhaul schedule from Caterpillar. This chart recommends a major overhaul at 27,000 hours but that is at a 51% load factor. Prime power generators typically run in the 60-70% load factor range. Toromont (Caterpillar's Ontario representative) recommends 20,000-hour intervals for major overhauls and all Canadian utilities use the 20,000-hour major overhaul interval for their 1,800rpm generators.

Service Hours and Fuel Consumption for the 3512C Engine		
Interval	**Fuel Consumption(1)**	**Fuel Consumption(2)**
250 Service Hours	32980 L (8712 US gal)	41534 L (10972 US gal)
500 Service Hours	65960 L (17425 US gal)	83067 L (21944 US gal)
1000 Service Hours	131921 L (34850 US gal)	166138 L (43889 US gal)
2000 Service Hours	263842 L (69700 US gal)	332275 L (87778 US gal)
3000 Service Hours	395765 L (104550 US gal)	498414 L (131667 US gal)
6000 Service Hours	791526 L (209099 US gal)	996824 L (263333 US gal)
Top End Overhaul	1187291 L (313649 US gal)	1495238 L (395000 US gal)
	9000 Service Hours	
Second Top End Overhaul	2374581 L (627298 US gal)	2990475 L (790000 US gal)
	18000 Service Hours	
Major Overhaul	34000 Service Hours	27000 Service Hours
	4485713 L (1185000 US gal)	

(1) Based on 39 percent load factor.
(2) Based on 51 percent load factor.

Figure 1: *Manufacturer's Maintenance Overhaul Schedule*

Remotes' Generator Replacement Policy

Although overhaul interval recommendations are provided, generator manufacturers do not publish recommended replacement intervals. However, in 2010, Remotes implemented a policy to replace 1800rpm generators when they reached their third overhaul interval (60,000 hours). The policy is based on Remotes' extensive experience with prime power generators. Remotes found that parts which are not replaced during an overhaul (engine block, crankshaft, camshafts) showed significant wear by 60,000 hours. When generators were run beyond 60,000 hours, this wear had proven to increase breakdowns and thereby affected customer reliability. For reference, 60,000 hours is equivalent to approximately two-million miles for a transport truck engine, which is well beyond their typical lifespan.

As the current Armstrong A & B unit engines have been rebuilt twice already and have over 60,000 operating hours, they are at the point of failure and in need of rebuilding the generators should be replaced as per Remotes' policy.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: This project is required to maintain the reliability of the electrical supply to the communities. Justification for this project is identical to many generator replacement projects completed by Remotes over the past 10 years, and Remotes' plan is based on similar investment and is considered good utility practice. All new installations will also comply with O. Reg. 22/04.

ii. *Cost-Benefit Analysis:* Alternatives will not ensure reliability of the electrical supply and thereby could affect the wellbeing of the communities. Generator replacement is the only alternative that has the benefit of ensuring dependable electrical supply in Armstrong, Collins and Whitesand.

iii. *Historical Investments & Outcomes Observed:* Generator replacements have shown to improve reliability and decrease maintenance costs compared to overhauling engines a third time. Historical generator replacement costs are listed in part 5 of Section A of this document.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. Conservation and Demand Management

Community demand reduction from CDM would not mitigate the lower reliability, higher maintenance costs and safety risks associated with running a high-hour engine. As a result, no viable CDM alternative has been identified for this project.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

Similar generator replacements have been completed by Remotes many times, so this is not an innovative project.

ATTACHMENT 1: ARMSTRONG UNIT PICTURES

Figure 2 shows the Armstrong A unit. The Armstrong B unit is identical.

Figure 2: *Armstrong A Unit*

Figure 3 below shows the right side of the Armstrong A unit with the exhaust manifold removed during maintenance.

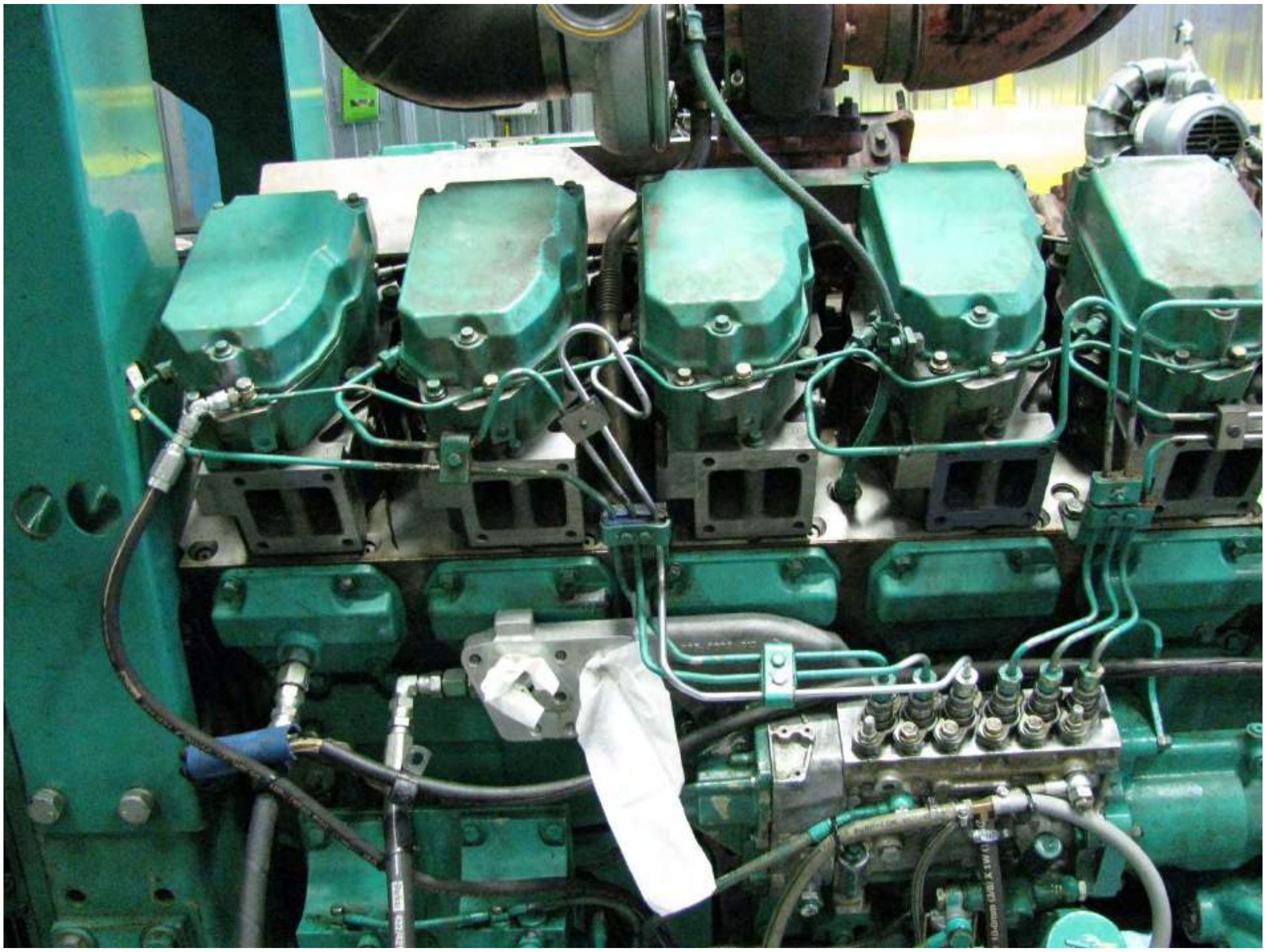


Figure 3: *Right Side of Armstrong A Unit.*

Material Investment Narrative

Big Trout Lake (KI) A Unit Generator Replacement

INVESTMENT SUMMARY	
Main Driver:	**Failure Risk**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	868	0	0	0	0

Summary:

This investment involves the replacement of Big Trout Lake Diesel Generation Station (DGS) with a modular DGS. The Big Trout Lake DGS relies on three generation units to supply electricity to over 411 customers in the community of Big Trout Lake. The Big Trout Lake A generation unit has reached the 60,000-hour engine operating threshold and is also in poor condition, and due to regulatory, safety and environmental issues identified throughout the existing DGS, the only suitable alternative is a full replacement of Big Trout Lake DGS. The proposed modular DGS will house three new generation units and the existing Big Trout Lake B and C generation units will be decommissioned and either placed into storage to be used as spare units or be auctioned off. The community of Big Trout Lake is expected to become grid-connected by the Watay Project in June 2023, which will reduce the community's reliance on diesel-generated electricity and at which time the new modular DGS will be used for providing backup power.

The investment is expected to ensure that the new modular DGS meets all of the standards and regulations and will ensure the continued delivery of safe and reliable backup-power generation in Big Trout Lake.

A. General Information on the Project/Program

1. Overview

The Big Trout Lake (KI) diesel generation station (DGS) was originally built in the 1980's and consists of 3 diesel generators: Big Trout Lake A, B and C. The plant currently supplies electricity to 411 customers in the community of Big Trout Lake. This community is expected to be grid-interconnected in June 2023, at which point the operating regime of the diesel units will change to providing backup power rather than baseload power. Through consultations with federal and provincial governments, the local communities and their project partners, Remotes has made a commitment to provide reliable back-up power in communities post-grid connection. The engine size, speed, vintage, condition and current and forecast engine hours for the Big Trout Lake units are summarized in Table 1.

Table 1: *Engine Condition of Generators in Big Trout Lake DGS*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition[2]	Engine Hours[1]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Big Trout Lake A	600	1,800	1996	Poor	62,364	63,857	100	200	300	400
Big Trout Lake B	1,000	1,800	2019	Very Good	17,178	23,562	100	200	300	400
Big Trout Lake C	1,000	1,200	2005	Good	61,510	62,961	100	200	300	400

[1] In-service year corresponds to the year the unit was installed.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The last condition assessment was carried out in November 2021.
[3] Engine-hours shown are current as of February 8, 2022.

The manufacturer's published recommendations for medium-speed generators (1,800 rpm) include complete overhauls after 20,000 hours, and Remotes has a policy that generators of this type shall be replaced once they reach the threshold for a third overhaul, generally at about 60,000 engine-hours. In addition, the units are inspected and maintained every 2,500 hours to determine the condition. The Big Trout Lake A unit has surpassed 60,000 operating hours and is rated to be in poor condition. An engine replacement was scheduled for this generator but unfortunately a like-for-like replacement generator was not available due to the vintage of the unit, and the existing engine room is not suitable for a modern replacement generator.

Remotes considered several options, but due to a number of regulatory, safety and environmental issues identified throughout the existing station (see Attachments 1, 2 and 3 for details), the only suitable alternative is to replace the DGS with a modular generating station built elsewhere and assembled at site (see Attachment 4 for an overview). This new modular generating station will house three new generator units with similar capacities and speeds to the existing units. Unit A will be retired because of its condition and high operating hours, but since Units B and C[1] have

[1] Note: Unit C is a low speed (1,200 rpm) generator. The manufacturer's published recommendations for low-speed generators include complete overhauls after 32,000 to 40,000 hours, and as per Remotes generator policy, the required replacement at the point of needing a third overhaul would be closer to the 96,000 – 120,000 hour mark. As a result, the Big Trout Lake C unit has only had a single rebuild to date and has a lot of operating hours remaining before requiring replacement.

relatively low operating hours, these units have the potential to be reused, kept as spares or be auctioned off. Remotes will assess the potential uses of these units further once they are taken out of service.

Remotes plans to invest $5.155M to complete the replacement of the DGS with a modular generating station. The new modular generating station will meet all the latest standards and regulations and will ensure safe and reliable supply of backup power to the community for years to come.

2. Timing

i. *Start Date:* April 2022

ii. *In-Service Date:* September 2023

iii. *Key factors that may affect timing:* Remotes has to time the work such that the winter road is available to transport the equipment and materials to site. A delay in receiving the necessary materials and equipment could delay the project by up to a year when the road is available again. The availability of materials and resources needed to complete the project can also impact timing.

3. Historical and Forecast Capital Expenditures

Table 2: *Historical and Forecast Expenditures ($' 000)*

	Historical Costs ($ '000)				Bridge Year[1]	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	4,287	868	0	0	0	0	5,155
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	4,287	868	0	0	0	0	5,155

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The chosen modular station alternative is novel for Remotes so there is no direct historical comparison available. Completed engine replacement projects are not a useful direct comparison for this project since a standard engine replacement project was not possible at Big Trout Lake and would have left the DGS with unaddressed regulatory, safety and environmental issues throughout the plant. All options considered for replacement required effort well beyond the scope of a typical engine replacement.

Remotes has also undertaken full station replacements historically, however the cost associated with a full DGS build is significantly more than the cost associated with building a modular station. For example, the last full station replacement was at Webequie in 2010 and cost $12M. The cost of a new station today built in a traditional style is estimated to be close to $20M.

6. Investment Priority

Big Trout Lake is scheduled for grid connection in 2023. Although this may appear to reduce the priority of this project, Remotes has made a commitment to provide backup power to the community after grid connection and this project is the most integral part of that commitment. The existing station is not suitable for backup power as a result of safety and environmental issues. This project is a priority to ensure reliable backup power can be provided to Big Trout Lake for years to come.

7. Alternatives Analysis

The following options have been considered in determining the proposed solution:

- Option 1: Do nothing – This is not a viable alternative as it would jeopardize the electricity supply to the community.

- Option 2: Like-for-Like Replacement – Like-for-like engine replacement and block replacement for Unit A were alternatives originally considered but found to be not possible due to the vintage of the unit. As a result, this option was discarded.

- Option 3: Rebuild Unit A Engine Room – The existing A unit room does not have a floor that provides spill containment (metal plates on wood joists) and is smaller than a typical engine room that houses a modern 600kW diesel generator. One alternative considered was to remove everything from the room and pour a concrete floor to provide spill containment. However, that would not have solved the space issue and Remotes had done a similar project in Fort Severn and found that the effort was similar to a building addition. As a result, this option was discarded.

- Option 4: Building Addition – An addition to the building was considered, the scope of which would be similar to the recent upgrade project in Marten Falls (approximately $7M). This alternative would not solve switchgear safety issues and fuel system compliance issues in the existing part of the station and would have still left the station being unsuitable to supply backup power. As a result, this option was discarded.

- Option 5: Building Addition & Upgrade Existing Facility – This alternative is similar to Option 4, but includes additional upgrade work to address the switchgear safety issues and fuel system compliance issues in the existing part of the station in order to make it suitable to supply backup power. This option will not be considered going forward as the cost to complete this option was estimated at approximately $9.5M.

- Option 6: Connect Temporary Trailer Unit – Another alternative considered was to connect a temporary trailer unit in parallel with the station until grid connection. However, this does not solve the switchgear safety issues and fuel system compliance issues in the existing part of the station and would have still left the station being unsuitable to supply backup power. Since temporary units are not a long-term solution, this would have also required Remotes to find a suitable way to provide backup power after grid connection. As a result, this option was discarded.

- Option 7: Replace Existing DGS with New Modular Station (Selected Option) – The final alternative was to install a complete modular station to replace the existing DGS. The modular station is expected to be built adjacent to the existing DGS, within the existing compound. This alternative had similar costs to the building addition but had the added benefit of alleviating issues with the fuel system and switchgear. This alternative was selected as it was the only option that allowed for reliable backup power generation after grid connection.

8. Innovative Nature of the Project

This project is innovative for Remotes but not for some other utilities and mines that use diesel generators for prime power. Modular stations have been proven by others to be a suitable alternative to a traditional DGS. A common concern for a modular station has been the limited space to work inside the modular units during maintenance overhauls. However, since this station will be used for backup power, it will not accumulate enough hours to require any generator overhauls in the next 10 years.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 3**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The newer units of the modular station will be more efficient than the vintage units they will replace. The new unit will also require less maintenance and repairs than the existing unit, thereby minimizing maintenance costs for the station. This in turn allows Remotes to direct staff to other critical maintenance and capital projects.
Customer Value	Installation of a newer, more reliable units allow Remotes to provide a reliable source of backup power to the community. Customers will also benefit from the reduced maintenance costs for the station which are included in rates.
Reliability	Although the existing DGS has been reliable, this is due to diligent maintenance and quick responses to trouble at the station in recent years. All equipment in the station is being operated near its capacity which does not lend itself to reliability. Reliability of the new units will be better relative to the existing units. Old engines are also more prone to catastrophic failures which, besides being a safety and fire risk, would affect reliability until a permanent replacement unit could be installed. The new modular units will provide good reliability with reduced maintenance efforts.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	The current DGS has exposed 600V within the control cabinets which presents a safety issue not seen at other Remotes stations. The switchgear is loaded to the point that extra cooling is required in the summer to avoid overheating. The fuel system is the oldest in Remotes inventory and of a construction that hasn't been allowed for decades in new construction. The modular station will satisfy all current electrical, fuel, and other codes to ensure it is safe. New units are also inherently safer and more dependable than old, nearly worn-out units. There are less chances for failures and leaks which could cause safety and fire issues.

2. Investment Need

i. *Main Driver*: Failure Risk – The Big Trout Lake A unit is an old unit on its second engine build that has surpassed the 60,000 operating hour threshold and is therefore more prone to failure. A failure of this unit prior to grid connection would significantly impact to Remotes' customers who rely on these units as their only source of electricity. Failure of this unit post-grid connection would also impact Remotes' customers as these units are required to provide backup power to the community in the event of an outage or failure on the grid. It is Remotes' policy, based on manufacturer's information and past experience, to replace generators when the engine requires a third overhaul, which is the case with this unit.

ii. *Secondary Drivers:* Regulatory, Safety & Environment – The Big Trout Lake DGS is one of only a couple of Remotes' generating stations that remain from the 1980's. Parts of it are original and no longer meet regulations, nor provide satisfactory safety for personnel and the environment. The required improvements to the station are such that it makes sense to replace the station and thereby alleviate all issues, rather than end up with a new unit and some random fixes in an old station

  a. *Regulatory:* All of Remotes' sites are audited as part of Remotes' Environmental Heath & Safety Management System (EHSMS). There are a number of outstanding audit findings for the Big Trout Lake DGS that require attention in order for the station to meet regulations and operate safely. Building a new modular station has the added benefit of eliminating all the outstanding issues. A summary of the outstanding deficiencies identified in the Big Trout Late EHSMS audit are included in Attachment 1.

  b. *Safety*: Switchgear at the existing DGS is undersized and unsafe to operate. Building a new modular station has the added benefit of eliminating this safety concern. Additional information on this safety issue is included in Attachment 2.

c. *Environmental:* The fuel system at the existing DGS is currently out of compliance. Building a new modular station has the added benefit of eliminating this concern. Additional information on this environmental issue is included in Attachment 3.

iii. *Information Used to Justify the Investment*: For the last 10 years, Remotes' generator policy has been used to help guide unit replacements. The policy is based on extensive maintenance and operating experience, consultation with other off-grid utilities, and manufacturer's recommendations. This policy is also a fundamental element of Remotes' AM process for diesel generators. Additional information on manufacturer recommendations and Remotes generator policy is included below, and further information on Remotes' generation AM process can be found in Section 5.3 of the DSP.

Manufacturer's Recommended Overhaul Interval

Figure 1 shows a representative maintenance overhaul schedule from Caterpillar. This chart recommends a major overhaul at 27,000 hours but that is at a 51% load factor. Prime power generators typically run in the 60-70% load factor range. Toromont (Caterpillar's Ontario representative) recommends 20,000-hour intervals for major overhauls and all Canadian utilities use the 20,000-hour major overhaul interval for their 1,800rpm generators.

Service Hours and Fuel Consumption for the 3512C Engine		
Interval	Fuel Consumption(1)	Fuel Consumption(2)
250 Service Hours	32980 L (8712 US gal)	41534 L (10972 US gal)
500 Service Hours	65960 L (17425 US gal)	83067 L (21944 US gal)
1000 Service Hours	131921 L (34850 US gal)	166138 L (43889 US gal)
2000 Service Hours	263842 L (69700 US gal)	332275 L (87778 US gal)
3000 Service Hours	395765 L (104550 US gal)	498414 L (131667 US gal)
6000 Service Hours	791526 L (209099 US gal)	996824 L (263333 US gal)
Top End Overhaul	1187291 L (313649 US gal)	1495238 L (395000 US gal)
	9000 Service Hours	
Second Top End Overhaul	2374581 L (627298 US gal)	2990475 L (790000 US gal)
	18000 Service Hours	
Major Overhaul	34000 Service Hours	27000 Service Hours
	4485713 L (1185000 US gal)	

(1) Based on 39 percent load factor.
(2) Based on 51 percent load factor.

***Figure 1**: Manufacturer's Maintenance Overhaul Schedule.*

Remotes' Generator Replacement Policy

Although overhaul interval recommendations are provided, generator manufacturers do not publish recommended replacement intervals. However, in 2010, Remotes implemented a policy to replace 1800rpm generators when they reached their third overhaul interval (60,000 hours). The policy is based on Remotes' extensive experience with prime power generators. Remotes found that parts which are not replaced during an overhaul (engine block, crankshaft, camshafts) showed significant wear by 60,000 hours. When generators were run beyond 60,000 hours, this wear had proven to increase breakdowns and thereby affected customer reliability. For reference, 60,000 hours is equivalent to approximately two-million miles for a transport truck engine, which is well beyond their typical lifespan.

As the current Big Trout Lake A unit engine is 26 years old, has been rebuilt twice already and has over 60,000 operating hours, it is at the point of failure and in need of rebuilding, the generator should be replaced as per Remotes' policy.

Regulatory, Safety & Environment Issues

In addition, the regulatory, safety and environmental issues identified at the existing DGS were also used to justify the need to replace the DGS with a new modular generating station. Additional information on these issues is included in Attachments 1, 2 and 3 of this material investment narrative.

Remotes' Commitment to Provide Backup Power

This community is expected to be grid-interconnected in June 2023, at which point the operating regime of the diesel units will change to providing backup power rather than baseload power. Remotes has participated in several studies and consultations focused on developing a backup power plan to support the 16 First Nation communities being connected to the provincial grid through the Watay transmission project. Studies have shown that without adequate backup power supply, the majority of the grid-connected communities would experience an increase in the frequency and duration of outages than they do currently. In addition, due to the remoteness and length of the transmission line, there is an increased risk of prolonged outages due to weather or forest fire.

Through these studies and consultations with federal and provincial governments, the local communities and their project partners, Remotes has committing to undertake the necessary actions and investments in order to provide reliable back-up power in communities post-grid connection until at least 2030. The diesel backup planning studies are included in the following DSP appendices:

- Appendix D - Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities (December 2018)
- Appendix E - Feasibility of Using Existing Diesel Generating Stations for Backup Power in Remote Grid-Connected Communities Containerized DGS Option Annex (November 2019)

- Appendix F - Backup Power Plan for the Connecting Communities of the Wataynikaneyap Transmission Project (April 30, 2020)

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: This project is required to maintain the reliability and availability of electrical supply to the community (existing and backup). Justification for the replacement of the Big Trout Lake A unit is identical to many generator replacement projects completed by Remotes over the past 10 years, and Remotes' plan is based on similar investment and is considered good utility practice. In addition, although building a modular station is novel for Remotes, modular stations have been proven by others (e.g., utilities and mines) to be a suitable alternative to a traditional DGS. All new installations will also comply with *O. Reg. 22/04*.

ii. *Cost-Benefit Analysis:* The only other alternative with the potential to address all the identified issues associated with this DGS is Option 5: Building Addition & Upgrade Existing Facility, however this option was estimated to cost approximately $9.5M which is nearly double the cost of the proposed solution. The selected option at a cost of $5.155 was found to be the most cost-effective solution that addresses the regulatory, safety and environmental issues while also allowing Remotes to provide reliable back up to the community power post-grid connection.

iii. *Historical Investments & Outcomes Observed:* Remotes has not had an identical investment in the past. A standard engine replacement project was not possible and would have left the station with unaddressed regulatory, safety and environmental issues. This project will address all issues by replacing the complete station in a cost-effective manner. The last full station replacement was at Webequie in 2010 and cost $12M. The cost of a new station today built in a traditional style is estimated to be close to $20M. Similar projects in the past have proven to increase reliability for customers while also decreasing environmental risks and environmental air impacts and improving employee and public safety.

iv. *Substantially Exceeding Materiality Threshold:* Additional justification for this project is included in the following attachments:
   - Attachment 1: Big Trout Lake DGS - EHSMS Audit Findings
   - Attachment 2: Big Trout Lake DGS - Safety Issues
   - Attachment 3: Big Trout Lake DGS - Environmental Issues

4. Conservation and Demand Management

The A unit represents 37% of the station rating. To defer the engine replacement, CDM would have to reduce demand by that amount which seems unrealistic in a community that always has positive growth. CDM would also not address the regulatory, safety and environmental issues identified at the existing DGS.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. INNOVATION

The innovative aspect of this project is the replacement of a complete station with a modular station built in the south and reassembled at site. This has never been done in any Ontario remote community. This project will provide experience that could encourage similar cost-effective station replacements in the future.

ATTACHMENT 1: BIG TROUT LAKE DGS - EHSMS AUDIT FINDINGS

The Big Trout Lake Diesel Generating Station (DGS) is one of only a couple of Remotes' generating stations that remain from the 1980's. Parts of it are original and no longer meet regulations, nor provide satisfactory safety for personnel and the environment. The required improvements to the station are such that it makes sense to replace the station and thereby alleviate all issues, rather than end up with a new unit and some random fixes in an old station.

Below is a list of outstanding audit findings for the Big Trout Lake DGS that require attention in order for the station to meet regulations and operate safely. ***The replacement project will eliminate all the issues listed below.***

- 7.2.1.1. Except as permitted in Clause 7.2.1.2, tanks shall conform to one or more of the following:(a) ULC Standards (refer to Standards); (b) Section VIII of the ASME Boiler and Pressure Vessel Code; (c) The Transportation of Dangerous Goods Act, c.36, and (d) CAN/CGSB 43.146.

  B139-15 6.2.1.2

  Day tanks do not have ULC labels.

- 7.2.2.1 Tanks shall not be operated at pressures exceeding 7.0 kPa (1 psi) gauge in the vapor space.

  B139-15 6.2.2.1

  Big Trout: Venting requirements are not met. Day tank vents are tied together and too small.

- 7.3.2 All tanks shall be installed in accordance with the manufacturer's instructions and the standard to which the tank has been manufactured.

  B139-15 6.3.2

  Hydraulic drain hose installed on tank.

- 7.3.4 The end or side of a supply tank shall be at least 50 mm (2 in) from a wall. See Figure 9.

  B139-15 6.3.6(a)

  One tank is too close to wall.

- 7.3.5 Supply tanks shall be installed so that there is at least 460 mm (18 in) clearance along one side and one end, ensuring clearance for service of any device attached to the supply line at the tank. See Figure 9 for an illustration of tank clearances. NOTE: The certification label on the tank should be visible after installation.

  B139-15 6.3.6(a)

  One tank does not have 18" clearance along one side.

- 7.3.6 When supply tanks are installed adjacent to one another, the space between the tanks shall be at least 100 mm (4 in), unless certified otherwise. See Figure 9.

  B139-15 6.3.6(b)

  Less than 4" between tanks.

- 7.3.8 A tank shall be

  (a) installed on rigid, non-combustible supports constructed of materials having a fire-resistance rating of not less that 2 h; and

  (b) securely supported to prevent settling, sliding, toppling, or lifting. Tank supports constructed of steel need not be protected if the tank bottom is less than 300 mm (12 in) high at its lowest point.

  B139-15 6.3.3

  Other sites: Tank legs are too high.

- 7.3.10 A tank shall:

  (c) if installed with a bottom outlet, be pitched towards the outlet with a longitudinal slope of not less than 1 in 50. A clearance of 100 mm (4 in) is considered sufficient for single wall tanks. Bottom connections with sloped supports are preferred for metallic tanks to minimize the accumulation of water in the bottom of the tank.

  B139-15 6.3.7(a)

  Clearance criteria is not met.

- 7.4.1 When installed inside a building, supply tanks(a) not larger than 45L (10 gal) shall be specifically approved for the purpose; or(b) larger than 45 L (10 gal) shall be constructed in accordance with Clause 7.2.1.

  B139-15 6.2.1.1

  No ULC listing located on the day tanks

- 7.4.8 The tank shall be located and operated so that the

  (a) temperature of the oil in the tank does not exceed 38^{o} C (100^{o} F);

  (b) horizontal distance from the tank to any fuel-fired appliance, other than a combustible-fuel-oil-driven internal combustion engine, is not less that 0.6 m (2 ft.), except when approved as part of an appliance or as permitted by Clause 10; and

  (c) tank installation does not interfere with the required working space of any electrical panel or apparatus. A minimum working space of 1 m with secure footing shall be provided.

  B139-15 6.2.3.2.1

  Unknown temperature in the day tank

- 7.9.2.1 Normal venting and emergency venting of an auxiliary supply tank (day tank) shall be (a) through an overflow pipe; or (b) installed directly to the outside and provided with two independent means of level control to shut off fuel supply to prevent overfilling of the auxiliary supply tank. NOTE: For CAN-LUC-S602 tanks and ULC ORD-C80 tanks, the normal and emergency venting are combined. B139-15 10.6.1 Big Trout: Level control does not meet the requirements of this code.

- 7.10.2 All tanks installed inside a building shall be provided with

  (a) a gauge that meets the requirements of ULC ORD-C180;

  (b) a device that meets the requirements of ULC ORD-C180 or ULC ORD-C58.15, to indicate at the point of filling when the liquid level in the tank has reached a predetermined

  (c) both the gauge and the device specified in items (a) and (b)

  B139-15 6.5.2

  Day tank sight glasses do not meet the requirements for liquid level gauges or devices.

- 7.10.5 A glass sight gauge or other gauging device that penetrates the tank shell shall not be fitted in a location that can

  (a) permit a discharge of oil from the tank at the normal liquid level within the tank; or

  (b) interfere with the operation of the vent alarm if the gauge were broken.

  B139-15 6.5.5

  Day tank sight glass could allow discharge at normal liquid level.

- 7.13.2 Tanks that directly supply engines shall be

  (a) double bottom;

  (b) double wall; or

  (c) a minimum 300^{o} integral secondary containment with monitoring of the interstitial space.

  B139-15 6.2.1

  Day tanks do not meet these criteria.

- 7.13.5 Where the engine fuel supply is from an auxiliary tank, the auxiliary tanks hall be equipped with an approved overfill protection device. The approved overfill protection device shall

  (a) result in the fill line pump(s) being shut off at a maximum fuel storage capacity of 90% of the volume of the auxiliary supply tank; and

  (b) be equipped with a separate circuit that will result in all the power to the fuel pumps being turned off should the liquid level in the tank reach 95% of the storage volume.

B139-15 6.2.3

Big Trout: Overfill protection not approved and not adequate.

- 7.14.2 Where the fuel being returned from the engine to the tank is at a temperature higher than 38° C (100° F),

  (a) the return line shall be connected to a drop tube that extends to a maximum of 15 cm (6 in) from the bottom of the tank; or

  (b) a cooling system shall be equipped on the return line from the engine that would result in the fuel being returned to the tank at a temperature lower than 38° C (100° F). NOTE: See Clause 7.5.7.

  B139-15 5.1.3

  These tanks do not have drop tubes.

- 7.14.3 The fuel lines from the tank to the engine shall enter the supply tank or auxiliary supply tank through fittings located on the top centerline of the tank.

  B139-15 6.2.2

  Non-compliant.

- 9.3.1.1 All piping and tubing, except as restricted in Clause 9.3.1.2 and permitted by Clause 9.3.1.4, shall be

  (a) new;

  (b) standard-weight wrought iron, steel or brass pipe;

  (c) brass, copper, or steel tubing; or

  (d) the equivalent with respect to strength, durability, and resistance to corrosion and temperature.

  B139-15 5.2.1.2

  Vent is copper.

- 9.3.4 Piping and tubing joints and connections shall be made in accordance with the following:

  (a) joints and connections shall be made fuel-oil-tight.

  (b) joints and connections shall be made with standard pipe fittings or by welding. All standard screwed fittings shall be malleable and shall comply with ANSI/ASME B16.3.

  (c) Welding connections shall be made by a welder acceptable to the authority having jurisdiction.

  (d) A joint in seamless copper, brass or steel tubing shall be

  (i) made by means of flare joint or approved fitting; or

  (ii) brazed with a material having a melting point exceeding 540° C (1000° F).

B139-15 5.3

Some black iron fittings present, don't comply with the regulation

- The current operating conditions (noise) at Big Trout DGS are non-compliant with noise levels specified in the Environmental Compliance Approval (ECA). The following is required to meet the ECA:
  - New mufflers and exhaust systems on A and B units,
  - New air intake silencers on A and B room
  - New radiators or fans on all four units (including backup unit)
- Inside Unit-A building the cable trench/sump was not concrete. Instead, it was old timber and exposed soil. A-Unit does not have secondary containment. If a spill were to occur in Unit A building the flammable liquid would escape to the natural environment through this low-lying area. Also, the site is all graded downwards from the generator rooms so a significant spill would cause a lot of flammable liquid to saturate the soil/groundwater on-site and flow off-site in the direction of the staff house.

ATTACHMENT 2: BIG TROUT LAKE DGS - SAFETY ISSUES

Exposed 600V in Generator Control Cabinets

Generator control cabinets are meant for low voltage only. High voltage components are typically housed in a separate compartment in the switchgear. Big Trout Lake's switchgear is of an old design where the 600V breaker with exposed lugs is housed within the generator control cabinets. This is a safety hazard for personnel. New switchgear is required to eliminate this hazard. The existing control room as seen in Figure 2 is not large enough for new switchgear so a building addition would be required to house the switchgear.

***Figure 2**: Generator Control Cabinet – Existing Control Room.*

Switchgear Loading

The load in Big Trout Lake has approached the rating of the switchgear. In the summer of 2020, the control room became so hot that doors had to be left open and fans were pointed at the switchgear components to prevent them from overheating. This is a fire hazard. Similar to the exposed 600V issue, new switchgear in a new building addition would be required to rectify the loading issue.

Lifting Devices

The station does not have overhead cranes and they cannot be installed due to low ceiling height. Portable gantry cranes are used during maintenance but are not as safe as an overhead crane. The modular station will allow a container to be shipped back to Thunder Bay for overhaul (if required) in a shop, thereby eliminating concerns with lifting heavy engine components.

ATTACHMENT 3: BIG TROUT LAKE DGS - ENVIRONMENTAL ISSUES

Fuel System Piping

One audit finding indicated piping material not allowed by the fuel code. All of the yellow pipes in the arrangement near the bottom of Figure 3 are non-compliant copper. This represents a leak and fire hazard. No other Remotes station uses copper pipe. All of this pipe, the day tanks, and some other fuel piping in the station require replacement to meet fuel regulations.

***Figure 3**: Fuel System Piping.*

“A” Generator Room Containment

The floor and genset base in the A unit room are comprised of metal plates on wood joists sitting on earth. There is no spill containment. Any fuel or coolant spill inside the room will end up in the ground.

This is one of only two generator rooms remaining in Remotes’ DGS’s without a spill-containing concrete floor. The other is in Weagamow and will be decommissioned when connected to the grid in 2022. All other generator rooms that had wood floors were either replaced with concrete or turned into a dry storage room. Remotes has not installed a new engine in a room without containment in over 20 years. The cost and effort to remove the wood floor and replace with a concrete floor was found to be high during an upgrade in Fort Severn. In the Big Trout Lake case, the room would still be smaller than typical for a 600 kW generator, which affects operating and maintenance. The only acceptable solution is to house the new generator in a new building.

***Figure 4**: Unit A Generator Room Flooring.*

Environmental Compliance Approval (ECA) non-compliance

Noise compliance is enforced by the Ontario Ministry of Environment, Conservation, & Parks (MECP). The noise at the nearest receptor (i.e., a house) must be within limits. The Big Trout Lake DGS is too loud at the nearest receptor and a consultant determined that to meet the noise threshold, new radiators, new exhaust on two units, and new ventilation silencers on two units would be required. These are substantial changes. The ventilation silencers are large and heavy which would require additional support to be installed inside the walls. Quieter mufflers would be much larger than the existing and therefore would require new exhaust towers which would need to sit on new concrete foundations.

ATTACHMENT 4: BIG TROUT LAKE DGS – MODULAR STATION OVERVIEW

Modular Station Layout

The modular diesel generation station consists of a common corridor connecting three identical modular generators and a modular control room, as shown in Figure 5.

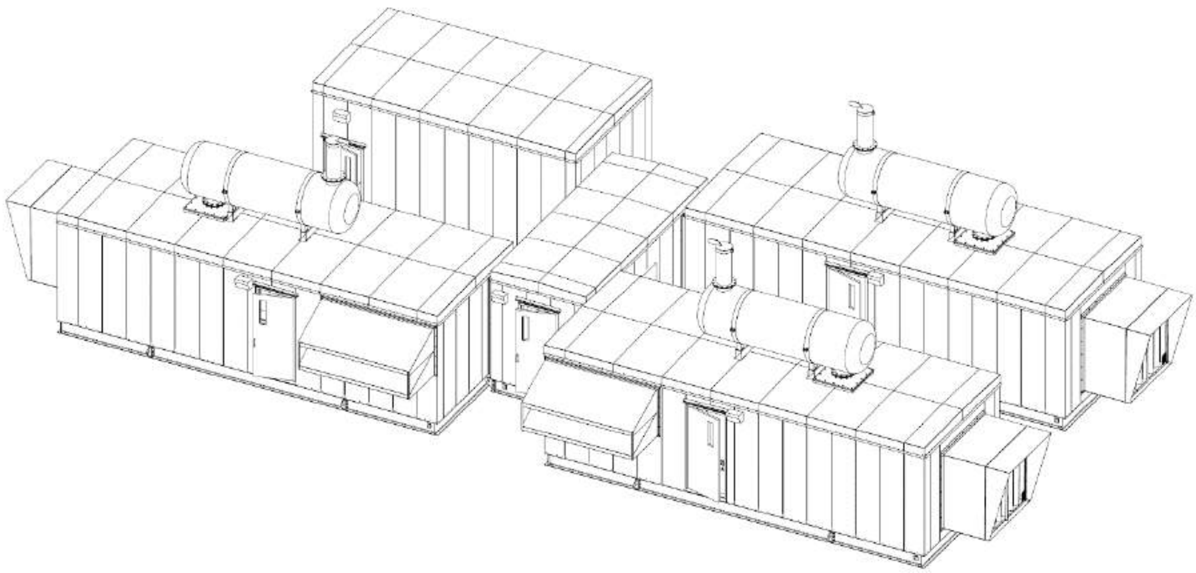


***Figure 5**: Modular Station Layout.*

Modular Generator Container Layout

The modular generator containers house all of the components required for the generator to operate. The only external connections are fuel from the existing bulk fuel farm, and power and control cables to the control room. The container layout is shown in Figure 6.

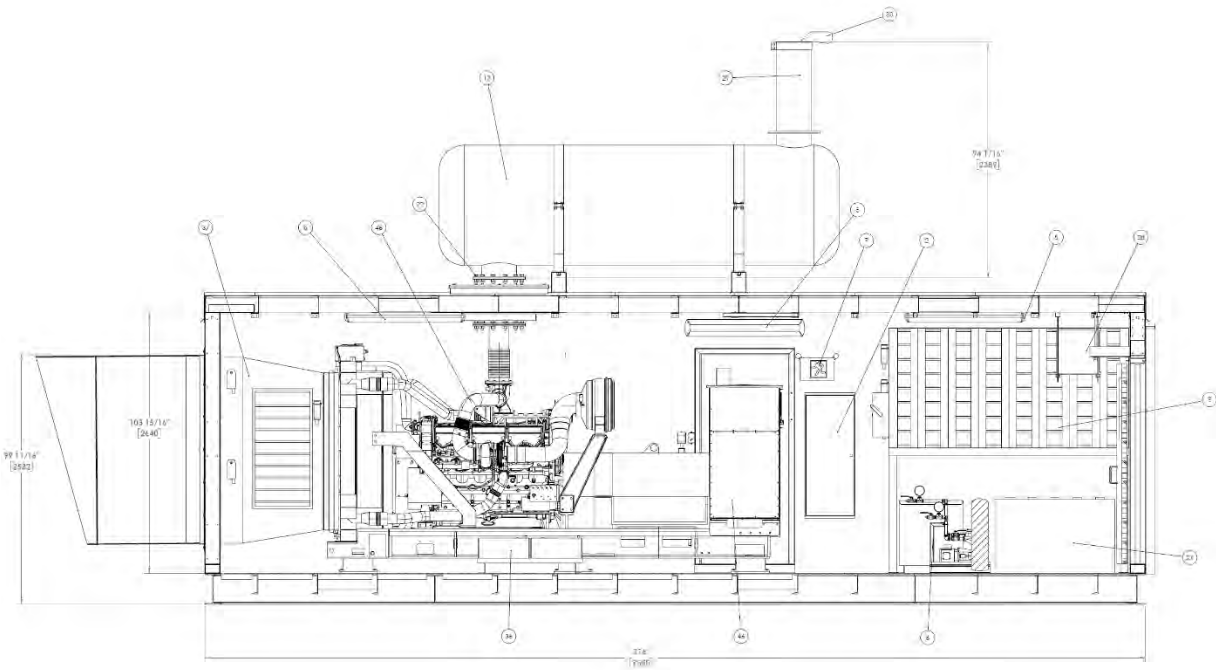


***Figure 6**: Modular Generator Container Layout.*

Site Layout

The modular station will be installed adjacent to the existing DGS, within the existing compound, as shown in Figure 7.

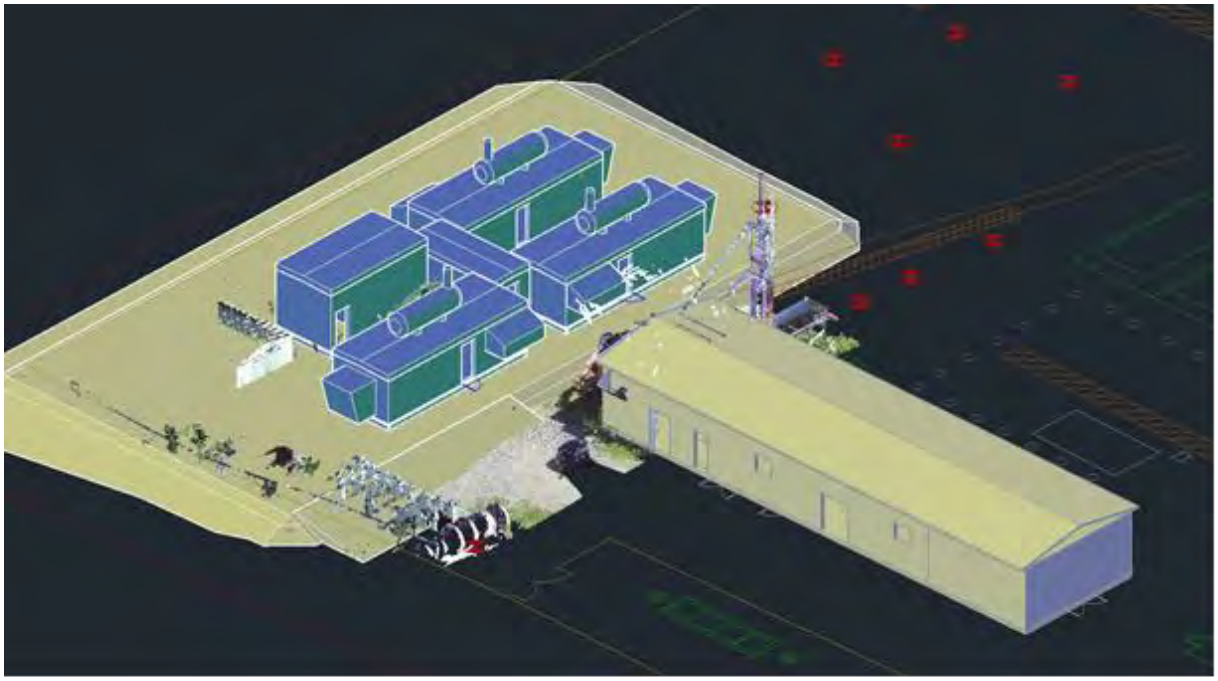


***Figure 7**: Modular Station Site Layout.*

Material Investment Narrative

Lansdowne House (Neskantaga) C Unit Generator Replacement

INVESTMENT SUMMARY

Main Driver:	**Failure Risk**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Cost	296	1,175	0	0	0

Summary:

This investment involves the planned replacement of the Lansdowne House Unit C generator. The C Unit generator has been assessed in fair condition and is forecast to exceed the 60,000 engine-hour threshold limit by 2024. As the community of Lansdowne will not be grid connected to the Watay Project, the replacement of the generation unit is critical to reliability of supply for existing customers.

By proactively addressing the condition of the generator, this investment is expected to mitigate failure risks to generation supply; and to support effective operation of the Lansdowne House DGS, which will be the only source of electricity for the community in the years to come.

A. General Information on the Project/Program

1. Overview

Portions of the Lansdowne House (Neskantaga) diesel generation station (DGS) were built between the 1980's and late 1990's and currently contain 3 diesel generators: Lansdowne House A, C and D. The plant currently supplies electricity to over 112 customers in the community of Lansdowne. This community will not be grid-connected when the Watay Transmission Project comes online, and as a result, these units are critical and are required to supply electricity to the community for years to come. The engine size, speed, vintage, condition and current and forecast engine hours are summarized in Table 1.

Table 1: *Engine Condition of Generators in Lansdowne House DGS*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition[2]	Engine Hours[3]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Lansdowne House A	275	1,800	2019	Very Good	2,813	5,077	7,341	9,605	11,869	14,133
Lansdowne House C	600	1,800	2014	Fair	49,104	54,945	60,826	66,706	72,586	78,467
Lansdowne House D	600	1,200	1999	Very Good	19,518	20,687	22,322	23,957	25,592	27,227

[1] In-service year corresponds to the year the unit was installed.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The last condition assessment was carried out in November 2021.
[3] Engine-hours shown are current as of February 8, 2022.

The manufacturer's published recommendations for medium-speed generators (1,800 rpm) include complete overhauls after 20,000 hours, and Remotes has a policy that generators of this type shall be replaced once they reach the threshold for a third overhaul, generally at about 60,000 engine-hours. In addition, the units are inspected and maintained every 2,500 hours to determine the condition. The Lansdowne House C Unit is in fair condition and is forecast to exceed the 60,000 engine-hour threshold by 2024. Therefore, an engine replacement has been scheduled for this generator in 2024, with the procurement of the replacement generator to take place in 2023. Assets are often ordered and transported to site a year in advance, to mitigate transportation risks (e.g., bad weather conditions & winter road availability) and long lead times.

Remotes plans to invest $1.471M to complete the replacement of the Lansdowne House C Unit. The replacement will be like-for-like, and the new unit will be compliant with the latest standards. This project is necessary to ensure continued delivery of safe and reliable electricity to the community. An image of the existing generator is shown in Attachment 1.

2. Timing

i. Start Date: March 2023

ii. In-Service Date: November 2024

iii. Key factors that may affect timing: As a result of the remote location of the Lansdowne House DGS, Remotes must time the work such that the winter road is available to transport the unit to site. A delay in receiving the necessary materials and equipment could delay the project by up to a year when the road is available again. The availability of resources needed to complete the project can also impact timing.

3. Historical and Future Capital Expenditures

***Table 2**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	0	296	1,175	0	0	0	1,471
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	296	1,175	0	0	0	1,471

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Typical generator replacements will require a new radiator, a complete aftercooler piping circuit, an upgraded exhaust system, and electrical control and power upgrades. Since Remotes is proposing a like-for-like replacement, the scope associated with this project is smaller than the scope associated with a typical engine replacement project since the radiators are correctly sized, the appropriate aftercooler circuit is already in place, and the exhaust is correctly sized. Only the controls may need an update depending on the compatibility of the newer engine controller. As a result, the cost associated with this project will be less than a typical generator replacement project, however other factors such as increases in material costs and inflation may also affect the overall cost.

The Lansdowne House C Unit like-for-like replacement is expected to cost $1.471M. In order to compare the cost to other similar generator replacement projects, cost per kW can be considered. The new 1,800 rpm generator unit will have a capacity of 600 kW, rendering the cost per kW at $2,452.

A generator replacement of similar scope was completed at Marten Falls in 2018, where a new 1,800 rpm generator unit with capacity of 400 kW was installed at the total cost of $1.43 M, and per-kW cost of $3,575. The observed cost differences can mostly be attributed to the difference in unit size and the greater level of piping work that was required as part of the Marten Falls project.

6. Investment Priority

This is a high priority project as it is integral in maintaining reliable prime-power generation in Lansdowne which is not being grid-connected. This DGS will be the only source of electricity for the community for years to come.

7. Alternatives Analysis

Remotes has considered the following options when determining the most appropriate option for the Lansdowne House C Unit:

- Option 1: Do Nothing – This is not a viable alternative as it would jeopardize the reliable electricity supply to the community.
- Option 2: Rebuild Engine – The C unit has already been overhauled twice. Rebuilding the engine a third time will result in decreased reliability and will increase the risk of safety and environmental spill incidents. As a result, this is not a viable option for long-term use.
- Option 3: Replace Engine (Selected Option) – Remotes' extensive experience with generators provides knowledge that after a third overhaul, engines are inherently less reliable and no longer perform satisfactorily. They have more wear on the block and crankshaft (parts that are not replaced during an overhaul) that will cause oil leaks, coolant leaks, and other issues that will require increased maintenance effort and costs. As these generators are critical sources of electricity for these remote communities, it is imperative to ensure these generators continue to function safely and reliability, and therefore Remotes has identified an engine replacement as the only viable option.

8. Innovative Nature of the Project

Engine replacements are routine in nature and are not considered innovative for Remotes. The new engine will be compliant with the latest standards.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 3**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Newer units offer improved efficiency relative to the vintage units they replace. The new unit will also require less maintenance and repairs than the existing unit, thereby minimizing maintenance costs for the station. This in turn allows Remotes to direct staff to other critical maintenance and capital projects.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	Installation of a newer, more reliable unit allows Remotes to continue providing a reliable source of electricity supply to the community. Remotes will also benefit from the reduced maintenance costs for the station.
Reliability	Reliability of the new unit will be better relative to the existing unit that has been rebuilt multiple times. Old engines are also more prone to catastrophic failures which, besides being a safety and fire risk, would affect reliability for months until a permanent replacement unit could be installed.
Safety	New units are inherently safer than old, nearly worn-out units. There are less chances for failures and leaks which could cause safety and fire issues.

2. Investment Need

i. Main Driver: Failure Risk – The Lansdowne C unit is an old unit on its second engine build that is approaching the 60,000 operating hour threshold and is therefore more prone to failure. A failure of this unit would significantly impact Remotes' customers who rely on these units as their only source of electricity.

ii. Secondary Drivers: It is Remotes' policy, based on manufacturer's information and past experience, to replace generators when the engine requires a third overhaul. This is the case with this unit, as it has already had two engine rebuilds. New engines are also more energy and fuel efficient and produce less air pollutants.

iii. Information Used to Justify the Investment: For the last 10 years, Remotes' generator policy has been used to help guide unit replacements. The policy is based on extensive maintenance and operating experience, consultation with other off-grid utilities, and manufacturer's recommendations. This policy is also a fundamental element of Remotes' AM process for diesel generators. Additional information on manufacturer recommendations and Remotes generator policy is included below, and further information on Remotes' generation AM process can be found in Section 5.3 of the DSP.

Manufacturer's Recommended Overhaul Interval

Figure 1 shows a representative maintenance overhaul schedule from Caterpillar. This chart recommends a major overhaul at 27,000 hours but that is at a 51% load factor. Prime power generators typically run in the 60-70% load factor range. Toromont (Caterpillar's Ontario representative) recommends 20,000-hour intervals for major overhauls and all Canadian utilities use the 20,000-hour major overhaul interval for their 1,800rpm generators.

Service Hours and Fuel Consumption for the 3512C Engine		
Interval	Fuel Consumption(1)	Fuel Consumption(2)
250 Service Hours	32980 L (8712 US gal)	41534 L (10972 US gal)
500 Service Hours	65960 L (17425 US gal)	83067 L (21944 US gal)
1000 Service Hours	131921 L (34850 US gal)	166138 L (43889 US gal)
2000 Service Hours	263842 L (69700 US gal)	332275 L (87778 US gal)
3000 Service Hours	395765 L (104550 US gal)	498414 L (131667 US gal)
6000 Service Hours	791526 L (209099 US gal)	996824 L (263333 US gal)
Top End Overhaul	1187291 L (313649 US gal)	1495238 L (395000 US gal)
	9000 Service Hours	
Second Top End Overhaul	2374581 L (627298 US gal)	2990475 L (790000 US gal)
	18000 Service Hours	
Major Overhaul	34000 Service Hours	27000 Service Hours
	4485713 L (1185000 US gal)	

(1) Based on 39 percent load factor.
(2) Based on 51 percent load factor.

***Figure 1**: Manufacturer's Maintenance Overhaul Schedule.*

Remotes' Generator Replacement Policy

Although overhaul interval recommendations are provided, generator manufacturers do not publish recommended replacement intervals. However, in 2010, Remotes implemented a policy to replace 1800rpm generators when they reached their third overhaul interval (60,000 hours). The policy is based on Remotes' extensive experience with prime power generators. Remotes found that parts which are not replaced during an overhaul (engine block, crankshaft, camshafts) showed significant wear by 60,000 hours. When generators were run beyond 60,000 hours, this wear had proven to increase breakdowns and thereby affected customer reliability. For reference, 60,000 hours is equivalent to approximately two-million miles for a transport truck engine, which is well beyond their typical lifespan.

As the current Lansdowne C unit engine has been rebuilt twice already and has over 60,000 operating hours, it is at the point of failure and in need of rebuilding, the generator should be replaced as per Remotes' policy.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: This project is required to maintain the reliability of the electrical supply to the community. Justification for this project is identical to many generator replacement projects completed by Remotes over the past 10 years, and Remotes' plan is based on similar investment and is considered good utility practice. All new installations will also comply with O. Reg. 22/04.

ii. *Cost-Benefit Analysis:* The alternatives will not ensure a safe and reliable electrical supply and thereby could affect the wellbeing of the community. The generator replacement is the only alternative that has the benefit of ensuring a reliable electrical supply in Lansdowne House.

iii. *Historical Investments & Outcomes Observed:* Generator replacements have shown to improve reliability and decrease maintenance costs compared to overhauling engines a third time. Historical generator replacement costs are listed in section 5 of section A of this document.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. Conservation and Demand Management

Community demand reduction from CDM would not mitigate the lower reliability, higher maintenance costs and safety risks associated with running a high-hour engine. As a result, no viable CDM alternative has been identified for this project.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

Similar generator replacements have been completed by Remotes many times, so this is not considered an innovative project.

ATTACHMENT 1: LANSDOWNE C UNIT PICTURES

Figure 2 shows the Lansdowne C unit in 2015.

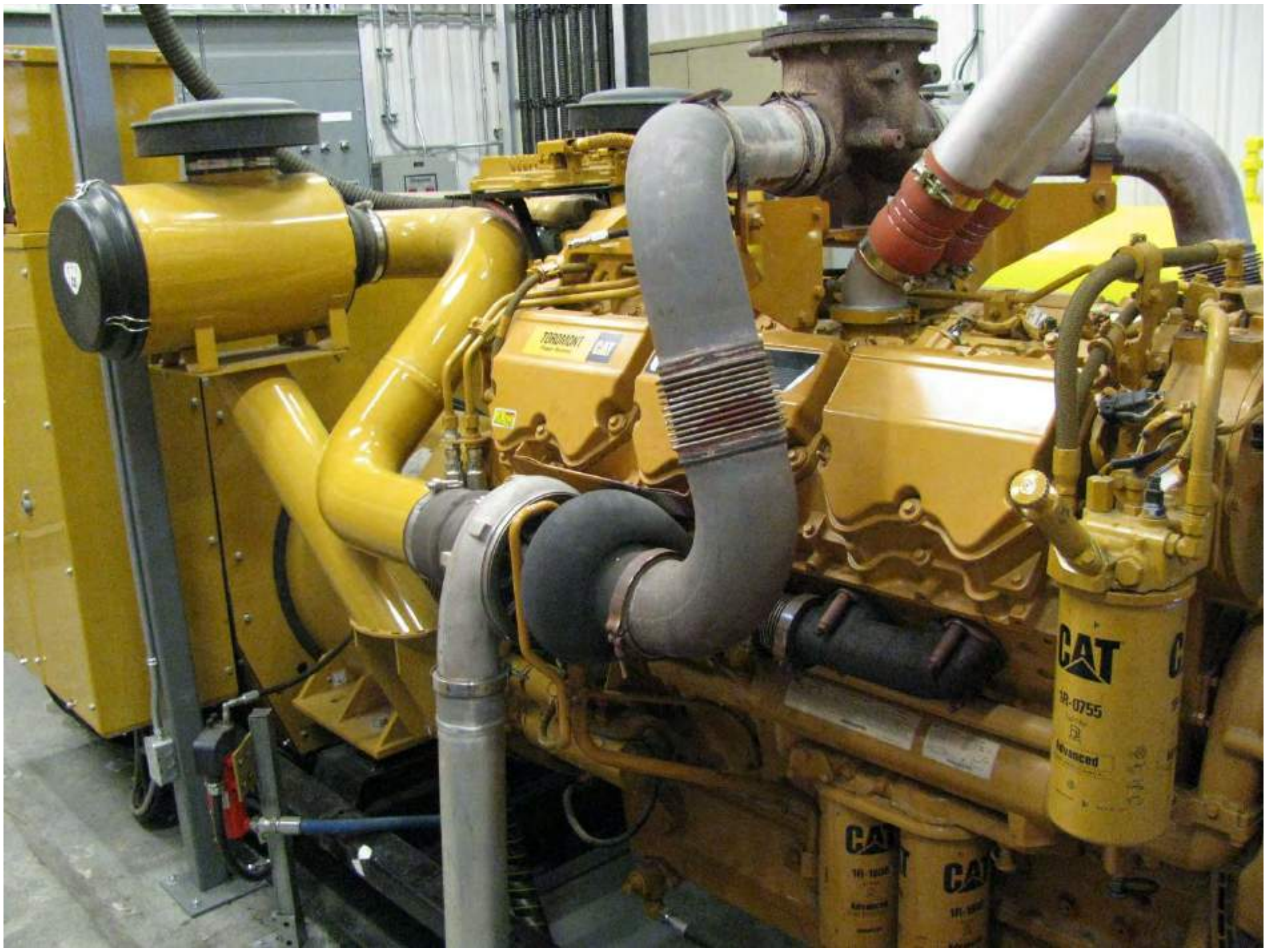


***Figure 2**: Lansdowne C Unit.*

Material Investment Narrative

Lansdowne House (Neskantaga) Bulk Tank Replacements

INVESTMENT SUMMARY

Main Driver:	**Regulatory Obligations**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness, Public Policy Responsiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	394	391	0	0	0

Summary:

This investment involves the planned replacement of two 50,000L bulk fuel tanks that are not compliant with current fuel regulations and are also assessed to be near end-of-life. Non-compliance with regulations will result in the need for additional fly-in fuel, to meet community generation demand.

By proactively addressing the non-compliance and condition issues, this investment is expected to mitigate reliability risks to fuel supply and support effective operation of the Lansdown House diesel generating station.

A. General Information on the Project/Program

1. Overview

The Lansdowne House (Neskantaga) diesel generating station (DGS) has five 50,000L bulk fuel tanks, totalling 250,000L, that store and supply fuel to the DGS to produce electricity. Lansdowne House DGS uses, on average, 20,000L per week. These tanks typically hold up to 10 weeks of fuel supply, while maintaining minimum levels.

All of Remotes' sites are audited as part of Remotes' Environmental Heath & Safety Management System (EHSMS). The Lansdowne House audits have found that two of the bulk fuel tanks (Tanks 1 & 2) do not have a manufacturer's nameplate installed which means there is no proof that the tanks have the necessary certifications to hold fuel and comply with Underwriters Laboratories of Canada (ULC) standards. This is a violation of fuel regulations. An excerpt from the EHSMS audit findings identifying this issue is shown in the following table.

***Table 1**: Summary of EHSMS Audit Findings*

Review Protocol	Item	Finding	Recommendation	Action
Fuel	**14.1** Approved standards of design and construction are used, but not be restricted to, (a) the following ULC Standards: (vi) ULC-S601; (vii) CAN/ULC-S603; (viii) CAN/ULC-S603.1; (ix) S615; (x) S630; (xi) CAN/ULC-S643; and (xii) S653; (b) API Standard 650;	Tank 3, 4 & 5 ULC approved. No plates on Tanks 1 & 2	Need to confirm ULC approvals for Tanks 1& 2	Confirm manufacture tanks certification & get nameplates installed
Fuel	**16.3** The double-wall AST system with a maximum capacity of 50 000 L conform to ULC Standards S653.	Tanks 1 & 2 have no plates to confirm, see 14.1	Should validate ULC standard	Confirm manufacture tanks certification & get nameplates installed

Remotes has contacted the tank manufacturer for assistance to confirm whether the manufacturer could recertify the existing tanks and supply new nameplates. However, the manufacturer was not able to not find any records of the tanks in question, and as a result was not able to provide a new nameplate or recertify the tanks.

Based on the timing of previous upgrades, Remotes has some certainty that Tanks 1 & 2 are 1990's vintage. Fuel tanks of this vintage are at or approaching end-of-life[1] and would require inspection, testing and re-certification for further long-term use (see Attachment 1 for pictures of existing tanks). Continuing to use older fuel tanks also increases failure risk associated with the

[1] There is no defined lifespan for these types of fuel tanks, but 25 years is their expected life.

tanks, which in turn poses environmental and fuel storage and supply risks. Lansdowne is not part of the Watay Project, so suitable long-term fuel storage capacity is a must.

Remotes is requesting $785,000 to replace Tanks 1 & 2 with two new 50,000L certified tanks that comply with all necessary standards. The new tanks will also eliminate the risk associated with continuing to use the older fuel tanks. The new tanks will also have engineered platforms on each side and a full safety railing. This will be a safety improvement over the existing tanks, that have a non-engineered platform on one side of the tank, and bring them up to meet the latest standards, which have evolved significantly since their initial installation.

2. Timing

i. *Start Date:* June 2023

ii. *In-Service Date:* September 2024

iii. *Key factors that may affect timing:* Remotes has to time the work such that the winter road is available to transport the tanks to site. If there is a delay in any materials or the supply of the tank from the manufacturer this could delay the project by up to a year when the road is available again.

3. Historical and Forecast Capital Expenditures

***Table 2**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ ‘000)				Bridge Year	Test Year	Forecast Costs ($‘000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	0	394	391	0	0	0	785
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	394	391	0	0	0	785

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The replacement of a 50,000L capacity bulk tank was completed in Hillsport in 2017 for $475,000, amounting to a per unit cost of approximately $9.5/L. Due to economies of scale, the cost to replace two 50,000L tanks at Lansdowne is less on a per unit basis. Replacement costs are estimated at $785,000 for the two tanks, which amounts to a per unit cost of $7.85/L.

6. Investment Priority

This is a high priority investment. The tanks were undoubtedly certified when new, so the risk of a spill is no higher than for a similar vintage tank. However, these tanks are currently in violation of fuel regulations, pose increased risk based on age, and will continue to be a finding in future audits unless the tanks are replaced. It is therefore a high priority to replace these tanks in order to comply with the latest fuel regulations.

7. Alternatives Analysis

The following options have been considered in determining the proposed solution:

- Option 1: Do Nothing – Doing nothing would mean continuing to use tanks that are in violation of fuel regulations and that do not follow the principles of the EHSMS system. Remotes must address all fuel system findings resulting from the audits in order to be compliant. Doing nothing is not a viable option. End of asset life and long-term need is also not addressed.
- Option 2: Recertification of the Tanks – Remotes has reached out to the tank manufacturer to confirm whether it is possible to recertify the existing tanks and install new nameplates. The manufacturer confirmed that they have no records of the two tanks in question, and as a result, the manufacturer is not able to recertify the tanks or supply new nameplates.
- Option 3: Install a Larger and Fewer Tanks – While above ground tank sizes can range up to 70,000-80,000L, it is more challenging and costly to transport and install larger tanks, particularly via winter road travel. One larger tank would also not provide sufficient capacity to replace the two 50,000L tanks with a total capacity of 100,000L. The current 50,000L size is common across Remotes' fleet and is easier to transport and install. As a result, this option was discarded.
- Option 4: Replace Tanks Like-for-Like (Selected Option) – A like-for-like replacement of the existing two tanks is the preferred option as these tanks are required to ensure sufficient fuel is available to continue operating the DGS in between the refilling of tanks. The new tanks will be certified and comply with all applicable standards and regulations.

8. Innovative Nature of the Project

There is nothing innovative for Remotes in this project. Remotes has completed similar replacement projects successfully in recent years.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 3**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Efficiency of the DGS will not be affected by this project. However, Remotes is planning to coordinate the replacement of both tanks at the same time to optimize efficiency and cost effectiveness.
Customer Value	If the uncertified tanks were flagged by fuel regulators (Technical Standards and Safety Authority, "TSSA") and directed to not be used, additional fly-in fuel would be required which would raise fuel costs that in turn are paid for by customers through rates. Replacing the uncertified tanks with new certified tanks will ensure continued supply of electricity to communities while maintaining affordability for customers.
Reliability	Reliability of the DGS will not be affected. However, the new tanks will eliminate the failure risk associated with continuing to use the older fuel tanks, which in turn will reduce the environmental risk and allow for continued reliable storage and supply of fuel to operate the DGS.
Safety	New tanks will have engineered platforms that will improve employee safety compared to the existing tanks. New tanks and associated fuel system components are also less prone to leaks or spills relative to older vintage tanks.

2. Investment Need

i. Main Driver: Regulatory Obligations – Remotes is obligated to ensure that its fuel tanks have the correct certifications to safely store and supply fuel and comply with all applicable standards and regulations. Currently two of the tanks at Lansdowne House are nearing end of life, have no clear nameplate and cannot be certified. Investment in new certified tanks is required to allow for continued storage and supply of fuel to operate the DGS and supply reliable and affordable electricity to the community of Lansdowne.

ii. Secondary Drivers*:* Failure Risk & Safety are secondary drivers for this project.

   a. Failure risk: Based on the timing of previous upgrades, Remotes has some certainty that Tanks 1 & 2 are 1990's vintage. Fuel tanks of this vintage are at or approaching end-of-life and will require inspection, testing and re-certification for further long-term use. Continuing to use older fuel tanks also increases failure risk associated with the tanks, which in turn poses environmental and fuel storage and supply risks. Lansdowne is not part of the Watay Project, so suitable long-term fuel storage capacity is a must.

b. Safety: the existing tanks do not have an engineered platform on each side, nor an engineered safety railing. The new tanks will have this and meet the latest safety standards.

iii. Information Used to Justify the Investment: Remotes regularly undertakes EHSMS audits and implements the necessary actions to satisfy audit findings as part of its focus on continuous improvement. This is done to ensure continued compliance with all applicable standards and regulations so that Remotes can continue providing safe and reliable electricity to customers. Remotes also conducts regular inspections and maintenance on tanks and associated equipment. Inspections and maintenance history are key inputs into Remotes' AM process, which is detailed further in Section 5.3 of the DSP.

3. INVESTMENT JUSTIFICATION

i. *Demonstrating Accepted Utility Practice*: Compliance with fuel regulations is necessary. When it is found that parts of fuel system do not meet regulations, Remotes takes the necessary steps to bring the system into compliance.

ii. *Cost-Benefit Analysis:* The other alternatives of do nothing or recertification (which has been confirmed as not possible) are not viable as they would not rectify the compliance issue. While Remotes could install larger tanks in theory, this is not recommended due to the logistics and costs of transporting these tanks on winter roads.

iii. *Historical Investments & Outcomes Observed:* Remotes has successfully replaced a number of bulk tanks historically. Historical replacements have been driven by a number of factors, including increased fuel and storage requirements, uncertified fuel systems, and end of life tanks. In all cases, replacements have met their intended outcomes and continue to perform as expected.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. CONSERVATION AND DEMAND MANAGEMENT

CDM is not applicable for this project.

i. *Project Deferrals*: This is not applicable.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. INNOVATION

This project has no innovative components for Remotes. All of the technology has been used in previous projects and has been proven to work.

ATTACHMENT 1: LANSDOWNE HOUSE TANK IMAGES

Pictures of the Lansdowne House tanks taken in 2007 are included in Figure 1 and Figure 2 below. The subject Tanks 1 and 2 are shown at the far end of Figure 1, and the non-engineered platforms and railings on only one side of the tanks are also visible in the pictures. As can be seen in these pictures, the tanks were showing their age even 15 years ago.

***Figure 1**: Lansdowne House Tanks*

***Figure 2**: Lansdowne House Tanks - Platforms and Railings*

Material Investment Narrative

Lansdowne House (Neskantaga) DGS Upgrade

INVESTMENT SUMMARY

Main Driver:	**Capacity Constraints**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	0	0	0	0	0

Summary:

Diesel generation station (DGS) capacity upgrade investments address system capacity issues that arise from community load growth. This investment involves the upgrade of the Lansdowne House A generation unit with a new 1,000 kW unit which, along with two other units, supply electricity to over 112 customers in the community of Lansdowne. The peak station load at Lansdowne House reached 703 kW in 2020, nearing its connection restriction limit of 744 kW, or 85% of the station prime rating. Since the community of Lansdowne will not be grid connected to the Wataay Project, a capacity upgrade of the Lansdowne House Unit A generator has become critical to reliability of supply for existing customers as well as forecast community load growth. The existing generation unit A will be decommissioned, and either be reused, placed into storage to be used as a spare unit or be auctioned off. The investment also replaces the step-up transformer. The Lansdowne House DGS upgrade costs are fully recoverable through a long-standing agreement with ISC.

The investment is expected to increase the Lansdowne House DGS prime rating from 875 kW to 1,200 kW and raise the connection limit to 1,020 kW. This investment addresses the capacity issue through the DGS upgrade, resulting in the continued ability of the system to meet forecast customer demand. By implementing this project, the customers in Lansdowne will be able to make new connections to the distribution system in order to add more housing and supply new critical infrastructure projects within the community.

A. General Information on the Project/Program

1. Overview

Portions of the Lansdowne House (Neskantaga) diesel generation station (DGS) were built between the 1980's and late 1990's and currently contain 3 diesel generators: Lansdowne House A, C and D. The DGS currently supplies electricity to over 112 customers in the community of Lansdowne. This community will not be grid-connected when the Watay Transmission Project comes online, and as a result, these units are critical and required to supply electricity to the community for years to come. The engine size, speed, vintage, condition and current and forecast engine hours are summarized in Table 1. Images of the Lansdowne service area and Lansdowne House DGS are included in Attachment 1.

Table 1*: Engine Condition of Generators in Lansdowne House DGS*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition[2]	Engine Hours[3]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Lansdowne House A	275	1,800	2019	Very Good	2,813	5,077	7,341	9,605	11,869	14,133
Lansdowne House C	600	1,800	2014	Fair	49,104	54,945	60,826	66,706	72,586	78,467
Lansdowne House D	600	1,200	1999	Very Good	19,518	20,687	22,322	23,957	25,592	27,227

[1] In-service year corresponds to the year the unit was installed.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The last condition assessment was carried out in November 2021.
[3] Engine-hours shown are current as of February 8, 2022.

The electrical demand in remote communities is continually increasing due to new infrastructure, new housing, and population growth. The DGS capacity must be larger than the peak demand to ensure Remotes can provide reliable power. When peak demand reaches 85% of the DGS capacity, new electrical connections are restricted in the community to ensure Remotes can continue to provide reliable service to existing customers. Connection restrictions can lead to a shortage of housing and delayed connection of new community infrastructure (arenas, schools, etc.).

The peak station load at Lansdowne House reached 703 kW in 2020, nearing its connection restriction limit of 744 kW, or 85% of the station prime rating (875 kW), which is based on the smallest two units in service. The peak demand in Lansdowne House is also expected to surpass 85% of the DGS capacity by 2023, thereby enacting connection restrictions. This DGS upgrade is required so that the community is not negatively affected by insufficient electrical capacity. Not increasing the station capacity will reflect poorly on Remotes when new connections for important community needs cannot be provided.

Remotes is proposing to increase the capacity of the Lansdowne House DGS by replacing the existing 275 kW Unit A generator with a new 1,000 kW unit that will become the new largest unit within the DGS. In addition, new transformers will also be installed to accommodate the increase in the new capacity. The upgrade will increase the station prime rating from 875 kW to 1,200 kW. This will allow for peak load growth in the community past the forecasting horizon of 2034. The

Lansdowne House Unit A, as seen in Figure 4 of Attachment 1, was selected for the upgrade as it is the smallest generator at the station and is seldom able to supply the community demand. Since this unit is still in very good condition and has low engine-hours, this unit will either be reused, kept as a spare or be auctioned off. Remotes will assess the potential uses of the unit further once it is taken out of service.

The Lansdowne House DGS Upgrade project is expected to cost $2.606M. Capital upgrade costs are fully recoverable through a long-standing agreement with Indigenous Services Canada (ISC). Remotes provide an estimate for the upgrade work to the Lansdowne House First Nation, who will then apply for funding from ISC. Once the funding is in place, Remotes is able to start the design and order long-lead materials. Any changes to scope and cost are discussed with the first nation and pre-approved with the ISC with all Remotes' costs fully recoverable.

By implementing this project, the customers in Lansdowne will be able to make new connections to the distribution system in order to add more housing and supply new critical infrastructure projects within the community. This upgrade is consistent with ensuring customers' expectations for unrestricted connection to the distribution system.

2. TIMING

i. Start Date: January 2023

ii. In-Service Date: November 2024

iii. Key factors that may affect timing: The timing of this project is dependent on ISC approval for the capital dollars required. Remotes also has to time the work such that the winter road is available to transport the materials to site. If there is a delay in any materials, especially long-lead items from the manufacturer, this could delay the project by up to a year when the winter road is available again. In addition, Remotes has to ensure it has the correct resources available to complete the project and that resources can be safely transported to site. Any changes to scope and design could delay the project as any changes to funding have to be approved by the ISC. Any delays in receiving the necessary environmental regulatory approvals (air and noise emissions) can also affect the project timing.

3. HISTORICAL AND FORECAST CAPITAL EXPENDITURES

***Table 2**: Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	0	501	2,105	0	0	0	2,606
Contributions	0	0	0	0	0	(501)	(2,105)	0	0	0	(2,606)
Capital (Net)	0	0	0	0	0	0	0	0	0	0	0

This is a multi-year project with in-service date of November 2024. Remotes serves customers of First Nation reserves under funding agreements with ISC. Under these agreements, ISC pays for capital related load growth. As a result, the capital costs associated with this work is 100% recoverable.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The Lansdowne House DGS Upgrade project is expected to cost $2.606M. In order to compare the cost to other station upgrade investments, cost per kW can be considered. The new 1,800 rpm generator unit has a capacity of 1,000 kW, rendering the cost per kW at $2,606.

A DGS upgrade of similar scope was completed at Fort Severn in 2015, where a new 1,200 rpm generator unit with capacity of 1,000 kW was installed at the total cost of $3.6M, and per-kW cost of $3,600. The observed cost differences can mostly be attributed to the complete floor replacement that was required at Fort Severn, which is currently not a requirement for the Lansdowne House DGS Upgrade project.

6. Investment Priority

This is a high priority investment. Without this investment, prolonged connection restrictions will be required which will have a negative effect on the community.

7. Alternatives Analysis

Remotes has considered the following options:

- Option 1: Do Nothing – Doing nothing will mean prolonged connection restrictions for the community which will limit the future growth and development of the community. Even with connection restrictions, there is demand growth among existing customers that would put pressure on the DGS and decrease reliability of the electrical supply. As a result, doing nothing is not a viable option.

- Option 2: Demand Management – This is not a long-term solution. This is a growing and developing community, so increased electrical capacity will be required to satisfy that growth.

- Option 3: Incorporating Alternative Sources – The cost of incorporating alternative generation sources such as renewables is very high, and they do not provide the necessary level of reliability. Renewable generation sources are also intermittent and are unable to provide baseload energy on their own. As a result, this is not a viable option.

- Option 4: Increase the Lansdowne House DGS Capacity (Selected Option) – This option includes replacing the existing 275 kW Lansdowne House A unit with a new 1,000 kW unit. This option will increase the station prime rating from 875 kW to 1,200 kW and allow for peak load growth in the community past the forecasting horizon of 2034. The proposed scope and associated cost currently assume that the new unit will be installed within the existing room, however additional assessment is required to confirm whether this is feasible. If the community supports Remotes' proposed option, they will pass a Band

Council Resolution to request funding from ISC. Upgrading the DGS capacity is the preferred option for the community of Lansdowne House.

8. Innovative Nature of the Project

There is nothing inherently innovative to Remotes about this project.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

***Table 3**: Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	By replacing the old generator with a new one that incorporates the latest technology, both diesel generation efficiency and carbon emission intensity would be positively affected. In addition, operating a newer more reliable unit will reduce the probability of unplanned failures. This means less callouts for unexpected maintenance response, allowing staff to be redeployed to other critical maintenance and capital project tasks.
Customer Value	The DGS upgrade will allow the community to connect new housing and new infrastructure projects (e.g., school, arena, community centre, etc.) to grow and develop their community over the forecast period and beyond.
Reliability	Since this is a known growing and developing community, this upgrade will eliminate estimated connection restrictions until at least 2034 while maintaining levels of reliability. Without the increased capacity, community demand will approach and eventually surpass the capacity of the DGS. This would negatively impact reliability because the generators and auxiliaries would be running at/or beyond their design limit, which often causes failures. Newer units are also less prone to unplanned failures and thus have improved reliability and generator availability.
Safety	By implementing this project, the DGS will not be operating near its rated capacity and therefore will have less chance of failures that could impose safety and fire risks. All upgrades to generator PLCs and related infrastructure will also meet the latest cyber-security standards.

2. Investment Need

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load has surpassed 85% of the station rating. The forecast peak load for Lansdowne is shown below in

Table **4**.

***Table 4**: Lansdowne Forecast Peak Load*

Community	Connection Limit (kW)	Forecast Peak Load (kW)					
		2022	2023	2024	2025	2026	2027
Lansdowne House	744	652	763	775	786	798	810

The existing DGS capacity is not sufficient to accommodate forecast growth in the community. Without an upgrade, connection restrictions will be required to protect the electrical supply for existing customers. The project will allow the Neskantaga First Nation to build and connect adequate housing to meet growing demand and connect new infrastructure projects that are beneficial to community residents. Sufficient generating capacity allows Remotes to continue providing reliable service and not negatively impact SAIDI and SAIFI as would happen if community demand surpassed the DGS capacity.

i. Main Driver: Capacity Constraints – Based on current projections and known upcoming developments, community growth and development will be stifled without this project. This DGS capacity upgrade is required to accommodate the growth and development in the community over the forecast period and beyond.

ii. Secondary Drivers*:* Reliability – Reliability of the power supply to existing customers will be affected without a DGS upgrade. By upgrading the station capacity, the reliability can be maintained at current levels for customers.

iii. Information Used to Justify the Investment: The need for this investment was identified through annual peak load forecasts, which is a key input into Remotes' planning and asset management process, as well as through ISC and community consultations. The forecasts have shown increased demand year over year and that community demand will surpass the DGS connection limit by 2023. Additional information on Remotes' asset management process and peak load forecasts can be found in Section 5.3 of the DSP.

3. INVESTMENT JUSTIFICATION

i. *Demonstrating Accepted Utility Practice*: Remotes' policy is to notify a community when their peak load reaches 75% of the DGS rating so they can prepare a funding request with ISC as they are responsible for capital upgrades to the DGS. It typically takes three years for a community to grow from 75% to 85% of the DGS rating, when connection restrictions are implemented. The 75% notification is meant to allow enough time to get the funding in place and complete the upgrade before connection restrictions are required to protect the electrical supply for existing customers. Even with connection restrictions, the demand from existing customers will continue to grow and will strain the DGS, affecting reliability. Upgrades ensure that stations are not loaded so highly that reliability is compromised. All necessary approvals for air and noise emissions will also be met for this project.

ii. *Cost-Benefit Analysis:* Alternatives will not allow Remotes to maintain the costs and electrical reliability for customers. A capacity upgrade is the only alternative that will allow Remotes to maintain the electrical reliability for existing customers while also accommodating new growth and development within the community.

iii. *Historical Investments & Outcomes Observed:* Remotes has undertaken similar DGS capacity upgrades in recent years. These investments have allowed continued growth and development within the communities which benefited residents. They also allowed Remotes to ensure dependable generation and reliability for existing customers.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. Conservation and Demand Management

i. *Project Deferrals:* CDM is not a long-term solution. Increased electrical capacity is required to accommodate the growing and developing community.

ii. *Cost-Benefit Analysis*: A capacity upgrade is the only alternative that will allow Remotes to maintain the electrical reliability for customers.

iii. *Use of Advanced Technology*: There is no advanced technology planned for this upgrade. Remotes is part of the Off-Grid Utilities Association (OGUA), a group of utilities that service off grid communities. Through that association and other interests, Remotes is not aware of any proven technology that can replace diesel generators for prime power at this time.

5. Innovation

There is nothing innovative in this project for Remotes.

ATTACHMENT 1: LANSDOWNE SERVICE AREA & DGS IMAGES

A map of the Lansdowne service area is shown in **Figure 1**.

***Figure 1**: Lansdowne Service Area Map.*

The Lansdowne House DGS is shown in Figure 2 and Figure 3 below.

***Figure 2**: Lansdowne House DGS Aerial View*

***Figure 3**: Lansdowne House DGS.*

The Lansdowne House Unit A generator is shown in Figure 4.

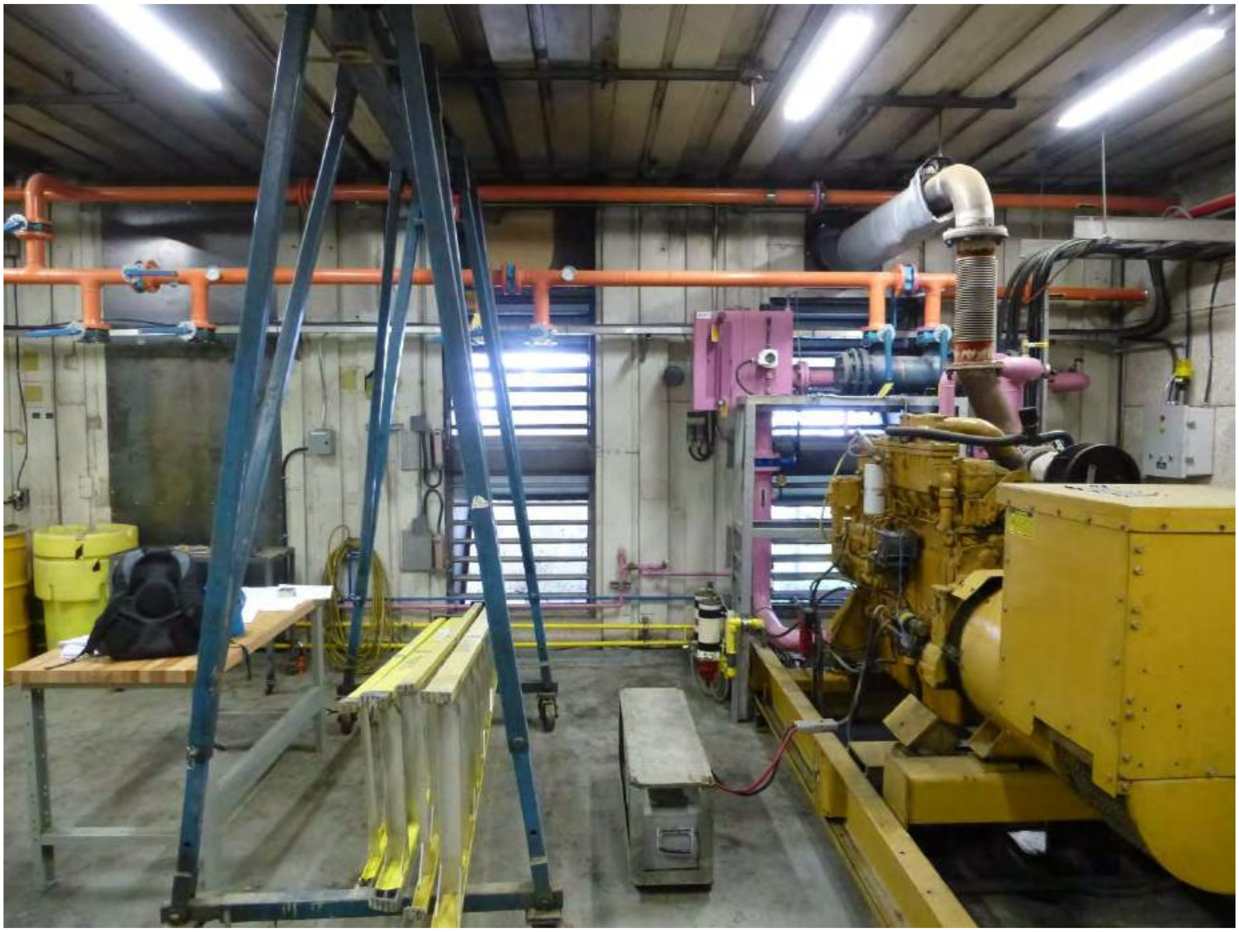


***Figure 4**: Lansdowne House Unit A Generator.*

Material Investment Narrative

Gull Bay (KZA) DGS Upgrade

Investment Summary

Main Driver:	**Capacity Constraints**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	0	0	0	0	0

Summary:

This investment involves the upgrade of the Gull Bay B generation unit with a new 725 kW unit which, along with two other units, supply electricity to over 123 customers in the growing community of Gull Bay. The community served by Gull Bay DGS will not be grid-connected by the Wataay Transmission project and will therefore continue to rely on diesel-generated electricity. Due to the continued growth in this community, the peak station load at Gull Bay DGS reached 340 kW in 2021 or 93% of the connection restriction limit and 85% of the station prime rating limit. The existing generation unit B will be decommissioned and either placed into storage to be used as a spare unit or be auctioned off. The investment also replaces the step-up transformer. This investment is 100% recoverable through a funding agreement with Gull Bay First Nation and ISC.

The investment is expected to increase the Gull Bay DGS prime rating from 430 kW to 650 kW and raise the connection limit to 553 kW, allowing for peak load growth in the community well into the future, and ensuring the continued delivery of safe and reliable prime-power generation in the community of Gull Bay.

A. General Information on the Project/Program

1. Overview

The Gull Bay (KZA) diesel generation station (DGS) was originally built in 2009 and consists of 3 diesel generators: Gull Bay A, B and C. The DGS currently supplies electricity to 123 customers in the growing community of Gull Bay. This community will not be grid-connected when the Watay Transmission Project comes online, and as a result, these units are critical and are required to supply electricity to the community for years to come. The engine size, speed, vintage, condition and current and forecast engine hours are summarized in Table 1. Images of the Gull Bay site location and Gull Bay DGS are included in Attachment 1.

Table 1: *Engine Condition of Generators in The Gull Bay DGS*

Generation Unit	Generator Capacity [kW]	Engine Speed [rpm]	In-Service Year[1]	Engine Condition[2]	Engine Hours[3]	Forecast Engine-Hours				
					2022	2023	2024	2025	2026	2027
Gull Bay A	400	1,800	2009	Good	22,071	24,804	27,945	31,945	35,945	39,945
Gull Bay B	180	1,800	2020	Very Good	4,824	8,766	1,500	4,500	7,500	10,500
Gull Bay C	250	1,800	2011	Good	20,146	21,072	22,102	23,131	24,161	25,190

[1] In-service year normally corresponds to the year the unit was installed.
[2] Engine condition is based on a combination of engine hours, number of times the engine was overhauled, and inspection data. The engine condition is current as of February 2022.
[3] Engine-hours shown are current as of February 8, 2022.

The electrical demand in remote communities is continually increasing due to new infrastructure, new housing, and population growth. The DGS capacity must be larger than the peak demand to ensure Remotes can continue to provide reliable power. When peak demand reaches 85% of the DGS capacity, new electrical connections are restricted in the community to ensure Remotes can continue to provide reliable service to existing customers. Connection restrictions can lead to a shortage of housing and delayed connection of new community infrastructure (arenas, schools, etc.).

The community of Gull Bay recently undertook a few big community projects, including building a new water treatment plant, and have plans to build a school as well, increasing demand on the system. The peak station load at Gull Bay reached 340 kW in 2021, nearing its connection restriction limit of 366 kW, or 85% of the station prime rating (430 kW), which is based on the two smallest units in service. With recent growth and infrastructural development in the community, the need for reliable and unrestricted access to electricity is increasing.

To continue accommodating these community driven projects and ensure that the community is not negatively affected by insufficient capacity, Remotes is proposing to increase the capacity of the Gull Bay DGS by replacing the existing 180 kW Gull Bay B generator (as seen in Figure 3 of Attachment 1), with a new 725 kW generator set. The station step-up transformers will also be replaced. The replacement of the generator and step up transformer will increase the station prime rating from 430 kW to 650 kW and raise the connection restriction limit to 553 kW. This will allow for peak load growth in the community past the forecasting horizon of 2034. Gull Bay Unit B was selected for the upgrade as it is the smallest generator at the station. Since this unit is still in good condition and has low engine-hours, this unit will either be reused, kept as a spare or be auctioned off. Remotes will assess the potential uses of Unit B further once it is taken out of service.

The project design was initiated in July 2019 as part of Phase 1 of this project, and Phase 2, corresponding to the purchase of long lead materials was initiated in January 2021. Phase 3 of this project, which is planned to be completed in August 2023, includes the purchase of remaining materials and the construction/installation of building support systems, generator, transformers, yard expansion and the building foundation to accommodate the larger unit. The overall Gull Bay DGS Upgrade project is expected to cost $5.6M. This work is 100% recoverable through a funding agreement with Gull Bay First Nation and Indigenous Services Canada (ISC). Once the funding is in place, a vendor will be selected by Gull Bay First Nation with recommendations from Remotes to construct the new building. The building contractor will have a contract directly with Gull Bay and be paid directly by the First Nation. If there is a requirement for any changes to the scope, design and cost, these are discussed with the Gull Bay First Nation community and approved with the ISC with all Remotes' costs fully recoverable.

By implementing this project, the customers in Gull Bay will be able to make new connections to the distribution system in order to add more housing and supply new critical infrastructure projects within the community. This upgrade is consistent with ensuring customers' expectations for unrestricted connection to the distribution system.

2. Timing

i. Start Date: July 2019

ii. In-Service Date: August 2023

iii. Key factors that may affect timing: The timing of this project is dependent on ISC approval for the capital dollars required. If there is a delay in any materials, especially long-lead items from the manufacturer, this could delay the project so Remotes must be diligent in its upfront planning activities. In addition, Remotes has to ensure it has the correct resources available to complete the project and that resources can be safely transported to site. Any changes to scope and design could delay the project as any changes to funding have to be approved by the ISC. Any delays in receiving the necessary environmental regulatory approvals (air and noise emissions) can also affect the project timing.

3. Historical and Forecast Capital Expenditures

Table 2: *Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($ '000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	300	0	1,300	1,300	2,700	0	0	0	0	5,600
Contributions	0	(300)	0	(1,300)	(1,300)	(2,700)	0	0	0	0	(5,600)
Capital (Net)	0	0	0	0	0	0	0	0	0	0	0

This is a multi-year project with in-service date of August 2023. Remotes serves customers of First Nation reserves under funding agreements with ISC. Under these agreements, ISC pays for capital related load growth. As a result, the capital costs associated with this work is 100% recoverable.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The planned total cost of this investment is $5.6M and includes a building expansion, the replacement of a generator set and station transformers, along with the associated construction costs. In order to compare the cost to other station upgrade investments, cost per kW can be considered. The new 1,800 rpm generator unit has a capacity of 825 kW, rendering the cost per kW at $6,787.

A DGS upgrade of similar scope was completed at Marten Falls in 2021, where a new 1,200 rpm generator unit with capacity of 1,045 kW was installed at the total cost of $5.8M, and per-kW cost of $5,550. The observed cost differences can mostly be attributed to the difference in generator rpm, increased material, transportation and labour costs, and inflation.

6. Investment Priority

This is a high priority investment. Without this investment, the Gull Bay First Nation community will not be able to make new connections to the distribution system, which will restrict their continued growth and development.

7. Alternatives Analysis

Remotes has considered the following options:

- Option 1: Do Nothing – Doing nothing will limit the future growth and development of the community. The community had several big projects in the recent years such as establishment of a water treatment plant, and now plans to build a school. Additional capacity is required to accommodate these customer driven projects and growth. As a result, doing nothing is not a viable option.

- Option 2: Demand Management – This is not a long-term solution. This is a growing and developing community, so increased electrical capacity is required to satisfy that growth.

- Option 3: Incorporating Alternative Sources – The cost of incorporating alternative generation sources such as renewables is very high, and they do not provide the necessary level of reliability. Renewable generation sources are also intermittent and are unable to provide baseload energy on their own. As a result, this is not a viable option.

- Option 4: Increase the Gull Bay DGS Capacity (Selected Option) – This option includes replacing the existing 180 kW Gull Bay B unit with a new 725 kW unit and replacing the station step-up transformers. This option will increase the station prime rating from 430 kW to 650 kW and allow for peak load growth in the community past the forecasting horizon of 2034. This is the preferred option for the community of Gull Bay.

8. Innovative Nature of the Project

There is nothing inherently innovative to Remotes about this project.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 3: *Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	By replacing the old generator with a new one that incorporates the latest technology, both diesel generation efficiency and carbon emission intensity would be positively affected. In addition, operating a newer more reliable unit will reduce the probability of unplanned failures. This means less callouts for unexpected maintenance response, allowing staff to be redeployed to other critical maintenance and capital project tasks.
Customer Value	The DGS upgrade will allow the community to connect new housing and new infrastructure projects (e.g., school, arena, community centre, etc.) to grow and develop their community over the forecast period and beyond.
Reliability	Since new infrastructure development projects are being undertaken in the community, this upgrade will eliminate connection restrictions until at least 2034 while maintaining levels of reliability. Without the increased capacity, community demand will approach and eventually surpass the capacity of the DGS. This would negatively impact reliability because the generators and auxiliaries would be running at/or beyond their design limit, which often causes failures. Newer units are also less prone to unplanned failures and thus have improved reliability and generator availability.
Safety	By implementing this project, the DGS will not be operating near its rated capacity and therefore will have less chance of failures that could impose safety and fire risks. All upgrades to generator PLCs and related infrastructure will also meet the latest cyber-security standards.

2. Investment Need

To accommodate customer and load growth, Remotes schedules generator upgrades in communities where the load has surpassed 85% of the station rating. The forecast peak load for Gull Bay is shown below in kW.

Table 4: *Gull Bay Forecast Peak Load*

Community	Connection Limit (kW)		Forecast Peak Load (kW)				
		2022	2023	2024	2025	2026	2027
Gull Bay	366	348	355	362	370	377	385

The existing DGS capacity is not sufficient to accommodate forecast growth in the community. Without an upgrade, connection restrictions will be required to protect the electrical supply for existing customers. This project will allow the Gull Bay First Nation community to build and connect adequate housing and other infrastructure to meet growing demands of the community. Sufficient generating capacity allows Remotes to continue providing reliable service and not negatively impact SAIDI and SAIFI as would happen if community demand surpassed DGS capacity.

i. Main Driver: Capacity Constraints – Based on current projections and known upcoming developments, community growth and development will be stifled without this project. This DGS capacity upgrade is required to accommodate the growth and development in the community over the forecast period and beyond.

ii. Secondary Drivers*:* Reliability – Reliability of the power supply to existing customers will be affected without a DGS upgrade. By upgrading the station capacity, the reliability can be maintained at current levels for customers.

iii. Information Used to Justify the Investment: The need for this investment was identified through annual peak load forecasts, which is a key input into Remotes' planning and asset management process, as well as through ISC and community consultations. New infrastructure projects in the community will require increased capacity and reliability, and peak load forecasts have shown that community demand will surpass the DGS connection limit by 2025. Additional information on Remotes' asset management process and peak load forecasts can be found in Section 5.3 of the DSP.

3. INVESTMENT JUSTIFICATION

i. *Demonstrating Accepted Utility Practice*: Remotes' policy is to notify a community when their peak load reaches 75% of the DGS rating so they can prepare a funding request with ISC as they are responsible for capital upgrades to the DGS. It typically takes three years for a community to grow from 75% to 85% of the DGS rating, when connection restrictions are implemented. The 75% notification is meant to allow enough time to get the funding in place and complete the upgrade before connection restrictions are required to protect the electrical supply for existing customers. Even with connection restrictions, the demand from existing customers will continue to grow and will strain the DGS, affecting reliability. Upgrades ensure that stations are not loaded so highly that reliability is compromised. All necessary approvals for air and noise emissions will also be met for this project.

ii. *Cost-Benefit Analysis:* Alternatives will not allow Remotes to maintain the costs and electrical reliability for customers. A capacity upgrade is the only alternative that will allow Remotes to maintain the electrical reliability for existing customers while also accommodating new growth and development within the community.

iii. *Historical Investments & Outcomes Observed:* Remotes has undertaken similar DGS capacity upgrades in recent years. These investments have allowed continued growth and development within the communities which benefited residents. They also allowed Remotes to ensure dependable generation and reliability for existing customers.

iv. *Substantially Exceeding Materiality Threshold:* The justifications for this project are included within this material investment narrative.

4. Conservation and Demand Management

i. *Project Deferrals:* CDM is not a long-term solution. Increased electrical capacity is required to accommodate the growing and developing community.

ii. *Cost-Benefit Analysis:* A capacity upgrade is the only alternative that will allow Remotes to maintain the electrical reliability for customers.

iii. *Use of Advanced Technology*: There is no advanced technology planned for this upgrade. Remotes is part of the Off-Grid Utilities Association (OGUA), a group of utilities that service off grid communities. Through that association and other interests, Remotes is not aware of any proven technology that can replace diesel generators for prime power at this time.

5. Innovation

There is nothing innovative in this project for Remotes.

ATTACHMENT 1: GULL BAY SERVICE AREA AND DGS IMAGES

Images of the Gull Bay DGS site location, Gull Bay DGS and Gull Bay B Unit generator are shown in Figure 1, Figure 2 and Figure 3, respectively.

Figure 1: *Gull Bay DGS Site Location*

Figure 2: *Gull Bay DGS.*

Figure 3: *Gull Bay B Generator.*

3D design upgrade models for the Gull Bay DGS are included in Figure 4 and Figure 5. The area highlighted in grey is the existing infrastructure, and the area highlighted in bright colours will be new additions to the station.

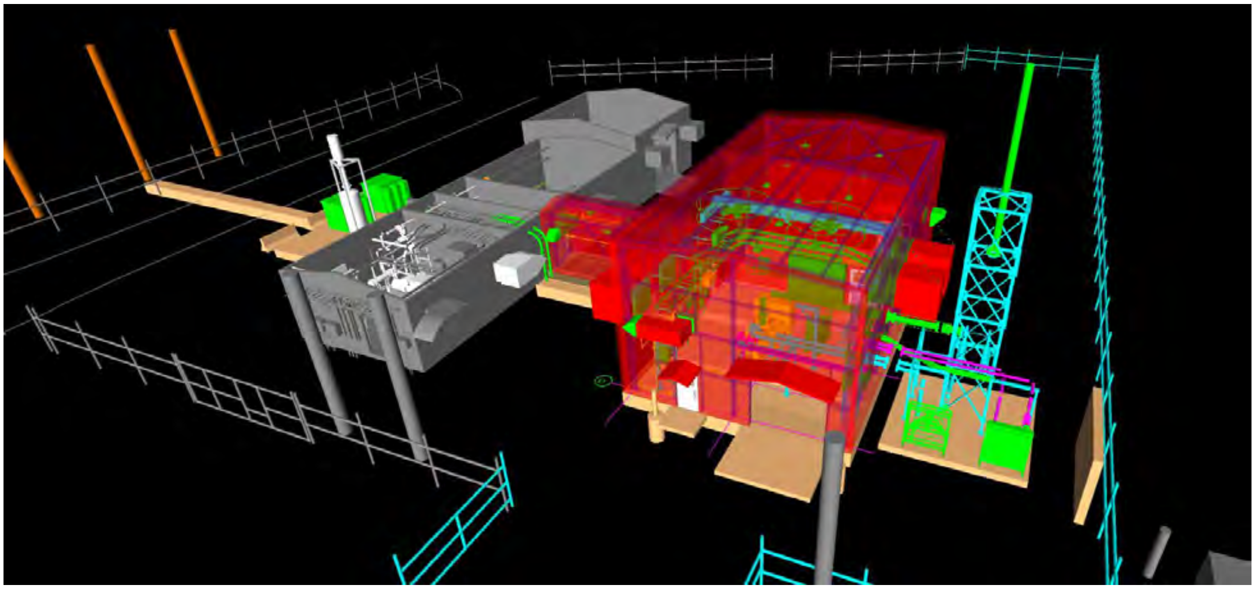


Figure 4: *3D Design Upgrade Model for the Gull Bay DGS*

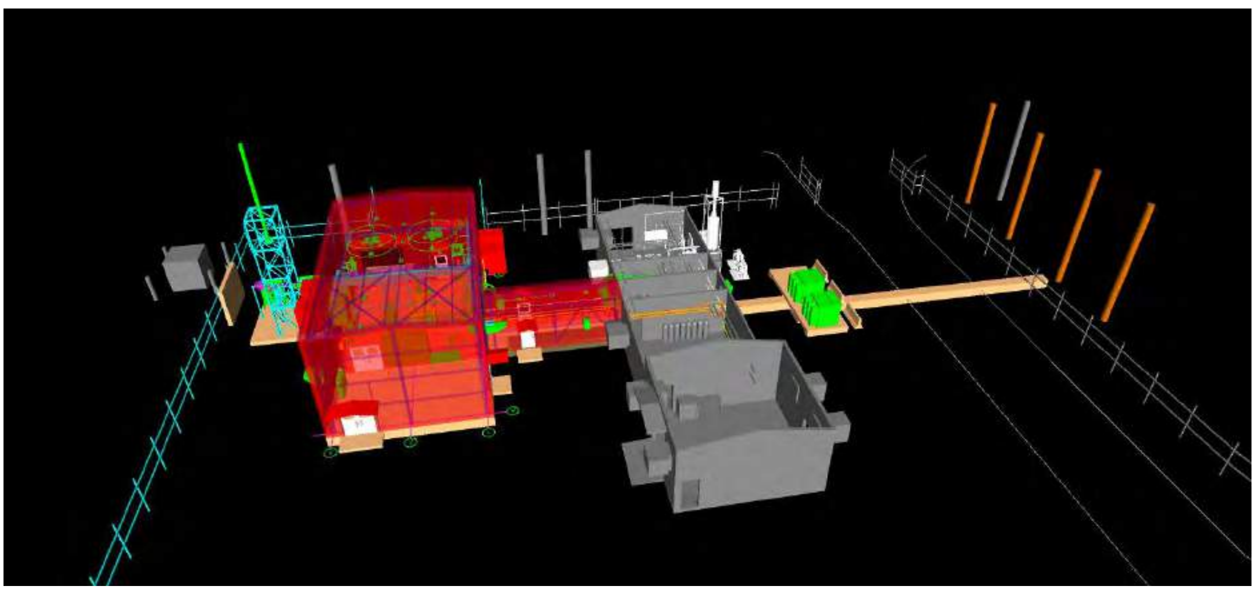


Figure 5: *3D Design Upgrade Model for the Gull Bay DGS.*

Material Investment Narrative

Beaverhall Facility Expansion/Relocation

Investment Summary

Main Driver:	**Non-System Physical Plant**
OEB RRF Outcomes:	**Customer Focus, Operational Effectiveness, Public Policy Responsiveness**

Forecast Capital Expenditures ($ '000):

	2023	2024	2025	2026	2027
Net Capital	1,476	0	0	0	0

Summary:

This investment involves the expansion or relocation of Remotes' main offices which are currently fully utilized and at capacity, and which will no longer adequately serve the needs of its customers. Remotes will also be required to increase current staff levels by up to four people in 2023 to account for the additional work associated with the six IPA communities being added to Remotes' customer base, as well as ensuring uninterrupted routine work. The investment also increases the available yard space for equipment and materials and create a dedicated shop space.

The investment is expected to provide the necessary space required to provide a workplace where employees can work safely in all areas of the facility and will allow Remotes to increase staffing resources to ensure that its customers receive quality customer service and reliable power. Working conditions are expected to improve as overcrowding is eliminated, while the increased yard space will allow for equipment and materials to be stored properly providing a safe area to work efficiently. Additionally, the increased shop space is expected to eliminate the need for trade staff to perform work in high traffic areas.

A. General Information on the Project/Program

1. Overview

Remotes' main office located at 680 Beaverhall Place no longer adequately serves the needs of the company. An expansion or relocation is required to provide an effective long-term solution as the business has grown and evolved over time. Increases in yard, shop and office space are required to meet the needs of Remotes staff and to support the continued operation of Remotes systems.

Remotes currently has 57 permanent staff and 12+ seasonal workers for a total of approximately 70 staff overall. Remotes will be required to increase staffing resources by up to four people for 2023 to account for the increase in work associated with the additional six Independent Power Authority (IPA) communities being added to Remotes' customer base in 2023 and 2024. Remotes will require additional staff to manage the additional workload to ensure that customers receive quality customer service and reliable power. In addition, there is a need to increase the yard and shop space to be able to support these additional communities.

Remotes has made investments into the building footprint in 2011 and 2012, installed a temporary office trailer in 2012 which is still in use, and fully utilizes all available office, yard and shop space, but a more appropriate long-term solution is required. This need is further strengthened by the additional staffing and space requirements associated with the Watay Project and addition of the six new IPA communities to Remotes' customer base.

Remotes has been exploring various options over the last two years to provide a solution to the limited office, shop and yard space. Remotes has enlisted an architectural firm to review the existing property to provide options of expanding the facility, within the limited remaining lot size. Remotes has also hired a real estate firm to provide a market analysis of the existing facility as well as other potential facilities available in the local area.

At the time of preparing this document, the preferred option has not been confirmed, but Remotes will continue to evaluate the options in 2022 and proceed with the optimal solution in 2023.

2. Timing

i. *Start Date*: August 2022

ii. *In-Service Date:* December 2023

iii. *Key factors that may affect timing:* The main factor is the availability of properties for sale and/or resources to complete expansion of the existing facilities. The return to office protocol and a proposed Hybrid work model related to the pandemic will also impact the timing of this need.

3. Historical and Forecast Capital Expenditures

Table 1: *Historical and Forecast Expenditures ($ '000)*

	Historical Costs ($ '000)				Bridge Year	Test Year	Forecast Costs ($'000)				Project Total
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Capital (Gross)	0	0	0	0	490	1,476	0	0	0	0	1,966
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	490	1,476	0	0	0	0	1,966

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Remotes has undertaken a few smaller upgrades and investments in its facilities in 2011 and 2012, but nothing in the last five years. Some of the older investments made are noted below for reference.

- 2011 – Mezzanine renovation to provide a new meeting room and an additional six desk spaces. ($300K)
- 2012 – New 30 x 40 civil shop built to provide a safe workspace for the civil crew. ($145K)
- 2012 – Temporary Office Trailer including desk space for four, plus storage. ($35K)

6. Investment Priority

Remotes currently utilizes all the available space of the existing facility and requires more space to meet the needs of the current staff and planned growth. In order to meet the demands of the business and customers Remotes need to provide a comfortable, safe and efficient space for employees to work. The existing facilities are no longer adequate and require upgrading or expansion to fulfill the business needs. This project is a high priority for Remotes to continue to operate safely and efficiently.

7. Alternatives Analysis

Remotes has been exploring various alternatives over the last two years to provide a solution due to the lack of office, shop and yard space. Remotes has enlisted an architectural firm to review the existing property to provide options of expanding the facility, within the limited remaining lot size. Remotes has also hired a real estate firm to provide a market analysis of the existing facility as well as other potential facilities available in the local area.

The project options being considered are:

- Option 1: Purchase Vacant Land for Yard Storage – This option includes the purchase of vacant land in close proximity to the existing facility for yard storage. This option would only provide a solution to Remotes' storage requirements, and as a result, Remotes would still need to investigate solutions to the office and shop space requirements. This option has been estimated at $500K.

- Option 2: Expand Office & Purchase Vacant Land for Yard Storage – This option includes expanding the existing facility and the purchase of nearby vacant land for yard storage. This option would provide the additional office space and yard space but there would be no additional shop space. This option is estimated at $1.5-$2M.
- Option 3: Purchase an Existing Local Facility – This option includes the purchase of a local facility that will be available in 2023 and selling the existing facility. This option is estimated at approximately $1.8-$2M. This cost does not include any potential gains from selling the current facility.
- Option 4: Custom Build on Vacant Land – Another option explored was to purchase property and build a new custom facility to meet the needs of Remotes. This option will not be considered going forward as the cost to complete this option was estimated to exceed $12M.

As previously noted above, the preferred option has not been confirmed, but Remotes will continue to evaluate the options in 2022 and proceed with the optimal solution in 2023. For planning purposes, Remotes has estimated that the project will cost approximately $2M.

8. Innovative Nature of the Project

While no final solution has been determined, Remotes is considering facilities and options with green energy solutions and reduced environmental impacts in mind.

9. Leave to Construct

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Table 2: *Investment Evaluation*

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The existing facility does not meet the requirements of the business which results in many inefficiencies while staff are completing their routine work. The increase in space will meet the needs of the business and allow the staff to work more efficiently and safely.
Customer Value	This investment would allow Remotes to have the space and facilities needed to continue meeting customer needs as it incorporates 6 additional IPA communities.
Reliability	This is not applicable.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	This investment would provide the necessary space required to provide a workplace where employees can work safely in all areas of the facility. The increased yard space would allow equipment and material to be stored properly providing a safe area to work efficiently. The increased office space would provide better working conditions and eliminate the overcrowding in meeting rooms and desk areas. A dedicated shop space would provide a safe work zone that eliminates the need for trade staff to perform work in high traffic areas.

2. Investment Need

i. *Main Driver*: Non-system physical plant - The existing facility (office, shop and yard) no longer meet the requirements of the business. This project is needed to address the essential needs to support the business and customers.

ii. *Secondary Drivers:* Business Operations Efficiency - Through upgrading to fit for purpose facilities, Remotes staff will be able to carry out its operations as efficiently and safely as possible, delivering to customer expectations.

iii. *Information Used to Justify the Investment*: The current facility was analyzed and compared to the actual requirement of the business. Table 3 illustrates the results of the analysis.

***Table 3**: Summary of Current Facility Analysis*

Summary of Facility Area	Current	Minimum Requirement	Ideal Requirement
Main building square footage	18,238	22,818	24,079
Trades shop / workable space square footage	5,700	6,150	6,825
Indoor cold storage	10,686	13,917	14,118
Outdoor storage (yard space for material)	20,000	24,000	26,000
Number of non-secured parking spaces	29	40	42
Number of parking spaces for equipment	20	20	20
Number of parking spaces (office staff)	30	40	42
Number of desk spaces (office staff)	50	55	55
Number of shop desk (trades staff)	20	22	26

Remotes has also engaged an architectural firm and real estate firm to design its requirements, source potential available sites and supply cost estimates. Alternatives being considered are listed in part 7 of section A and are supported by the attached documents.

3. Investment Justification

i. *Demonstrating Accepted Utility Practice*: The driver for this project is to meet the space requirements of Remotes' business. This will improve the safety and efficiency of the Remotes operating facility directly impacting employee health, safety and working conditions. The project will also improve employee morale. It is prudent and good utility practice to ensure appropriate office, workshop and yard storage space to facilitate the customer needs now and in the future.

ii. *Cost-Benefit Analysis:* This will be further investigated in 2022 to determine the best cost-benefit solution for Remotes.

iii. *Historical Investments & Outcomes Observed:* Remotes has undertaken a number of smaller upgrades and investments in its facilities in 2011 and 2012, which have enabled Remotes to carry out its job efficiently and safely. No new investments have been made in the last five years.

iv. *Substantially Exceeding Materiality Threshold:* Alternatives being considered by Remotes are listed above in part 7 of section A, and are further supported by the attached documents:
- Attachment 1: Drawings Issued for Costing – This document was prepared by the architectural firm Form Studio Architects Inc. and includes several architectural drawing options issued for costing purposes.
- Attachment 2: Cost Estimates – This document was prepared by Postma Quantity Surveying and includes Class D Cost estimates for the architectural drawing options 1b & 2 outlined in Attachment 1.
- Attachment 3: Property Appraisal of 680 Beaverhall Place – This document was prepared by Andrew, Thompson & Associates (ATA) Ltd. Real Estate Advisors and includes the investigation and analysis of the property as of July 28, 2021.
- Attachment 4: Consulting Report of Alternate Building / Site Opportunities – This document was prepared by ATA Real Estate Advisors and includes the resulting site / building availability search for new facilities in the Thunder Bay Market.

4. Conservation and Demand Management

CDM is not applicable for facility expansions or relocations.

i. *Project Deferrals:* This is not applicable.

ii. *Cost-Benefit Analysis*: This is not applicable.

iii. *Use of Advanced Technology*: This is not applicable.

5. Innovation

As noted above, Remotes is considering facilities with green energy options as potential options for this project.

ATTACHMENT 1:

DRAWINGS ISSUED FOR CONSTRUCTION

Form Studio Architects Inc.

0 1 2 3 5 10m

NORTH

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Existing - Main Floor

Project No: 2019047

SD.01

Date: 2019.10.09

Circulation
Common
Customer Service & Bus. Integration
Distribution
Finance
Generation
Managing Director
Shop
Storage
Washroom

Form Studio Architects Inc.

0 1 2 3 5 10m

NORTH

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Existing - 2nd Floor

Project No: 2019047

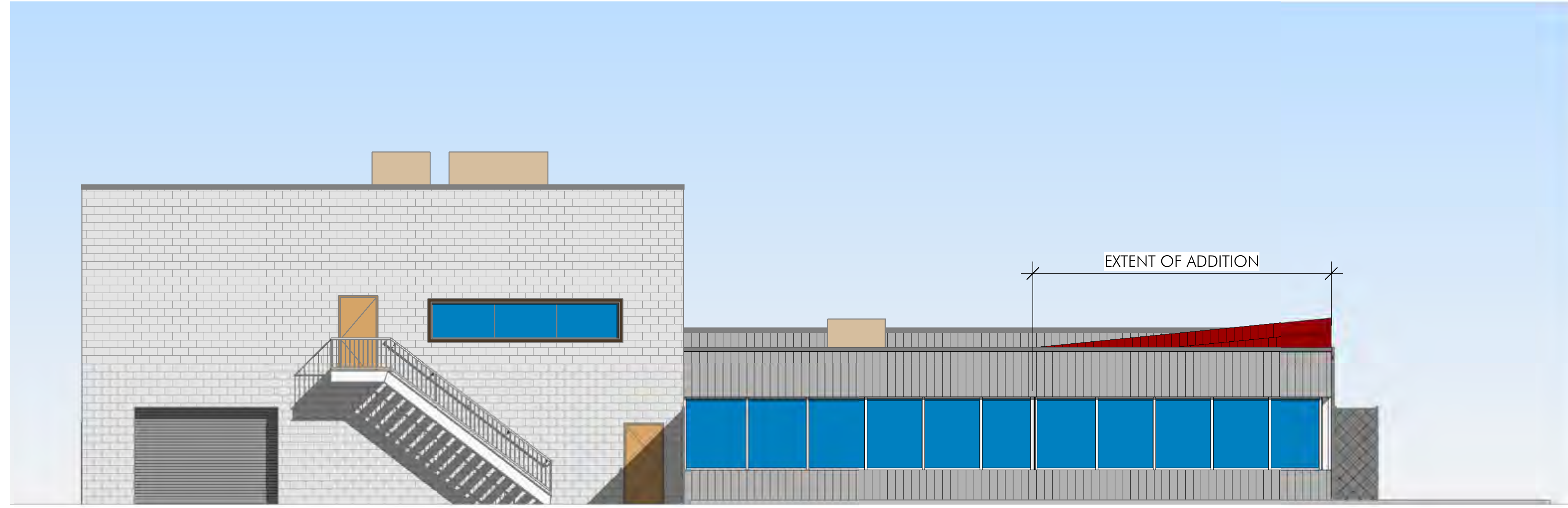
SD.02

Date: 2019.10.09

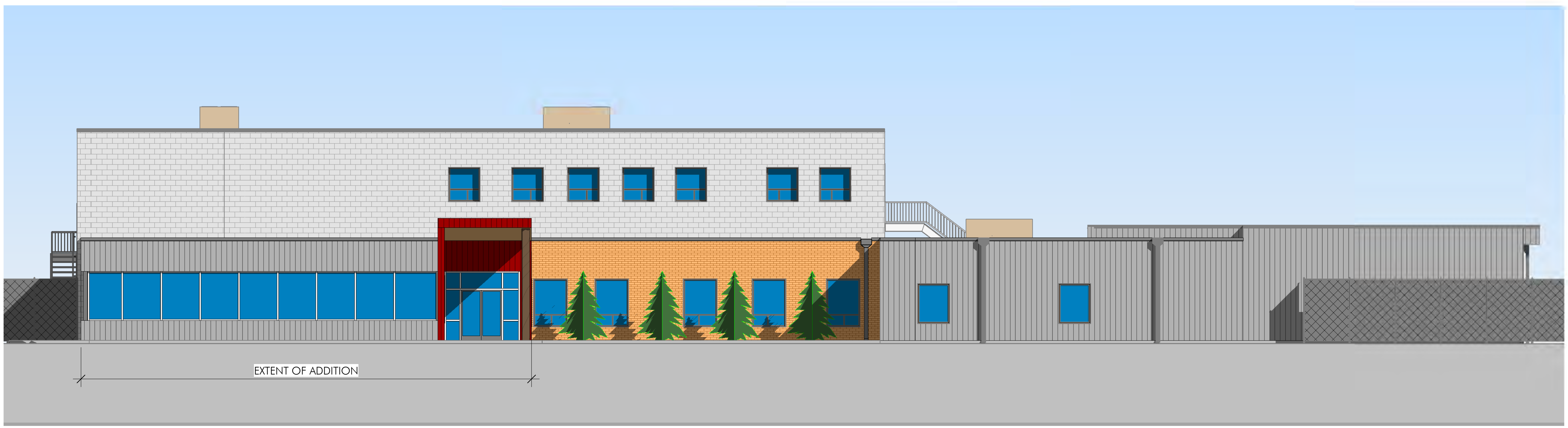
Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 1b - Main Floor
Project No: 2019047

SD.06
Date: 2019.10.09



1 SD.07 Elevation North - 1b
scale = 1 : 150

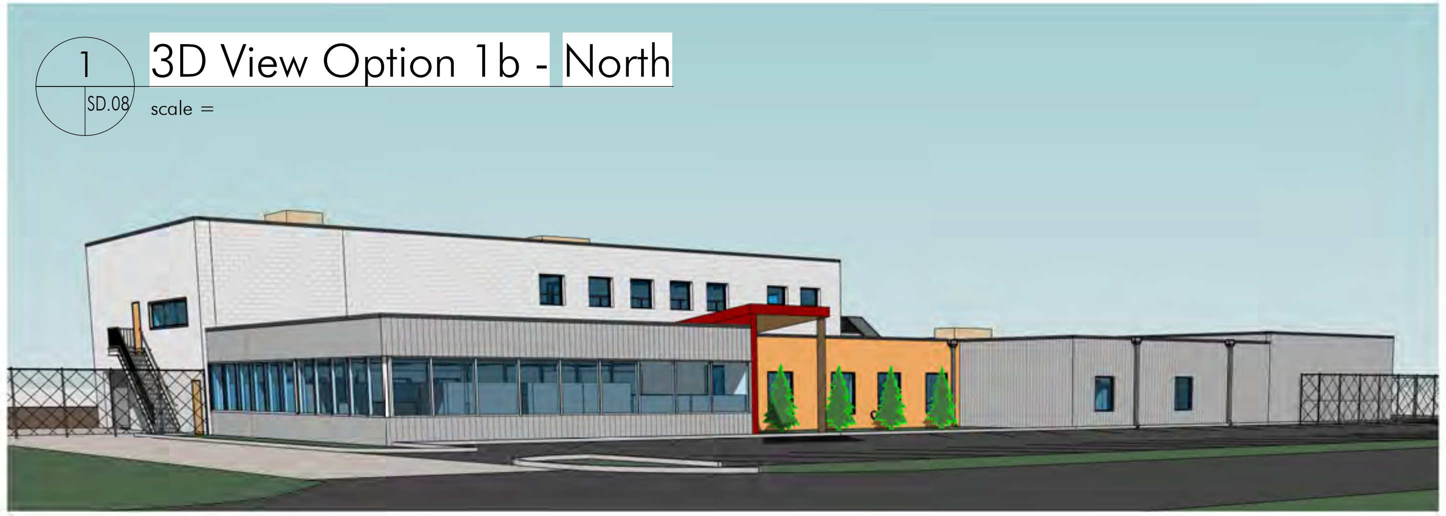


2 SD.07 Elevation West - 1b
scale = 1 : 150

Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 1b - Elevations
Project No: 2019047

SD.07
Date: 2019.10.09



Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 1b - 3d Views

Project No: 2019047

SD.08

Date: 2019.10.09

Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 1b - Demolition

Project No: 2019047

SD.15

Date: 2019.10.09

Form Studio Architects Inc.

0 1 2 3 5 10m

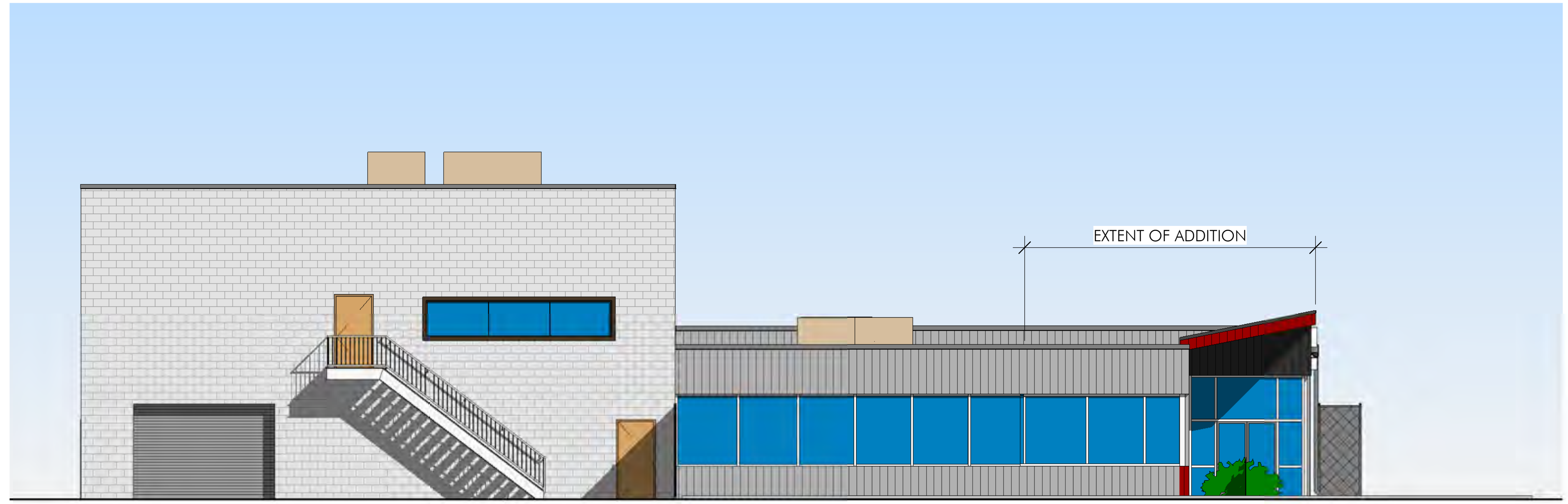
NORTH

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 2 - Main Floor

Project No: 2019047

SD.09

Date: 2019.10.09



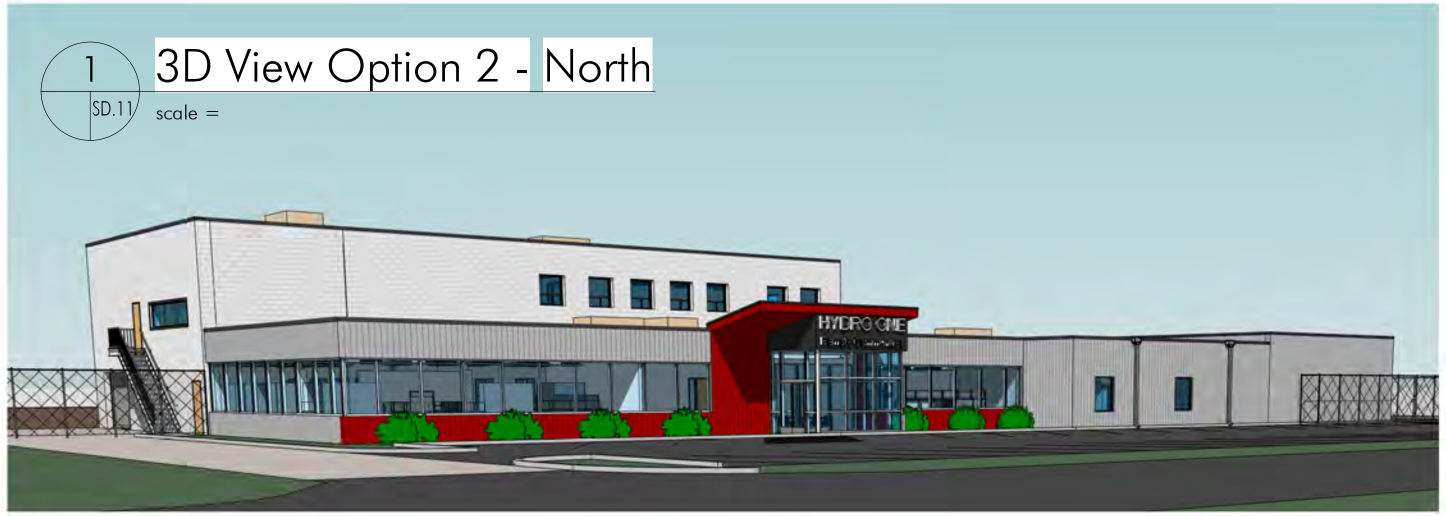
1 SD.10 Elevation North - 2
scale = 1 : 150

2 SD.10 Elevation West - 2
scale = 1 : 150

Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 2 - Elevations
Project No: 2019047

SD.10
Date: 2019.10.09



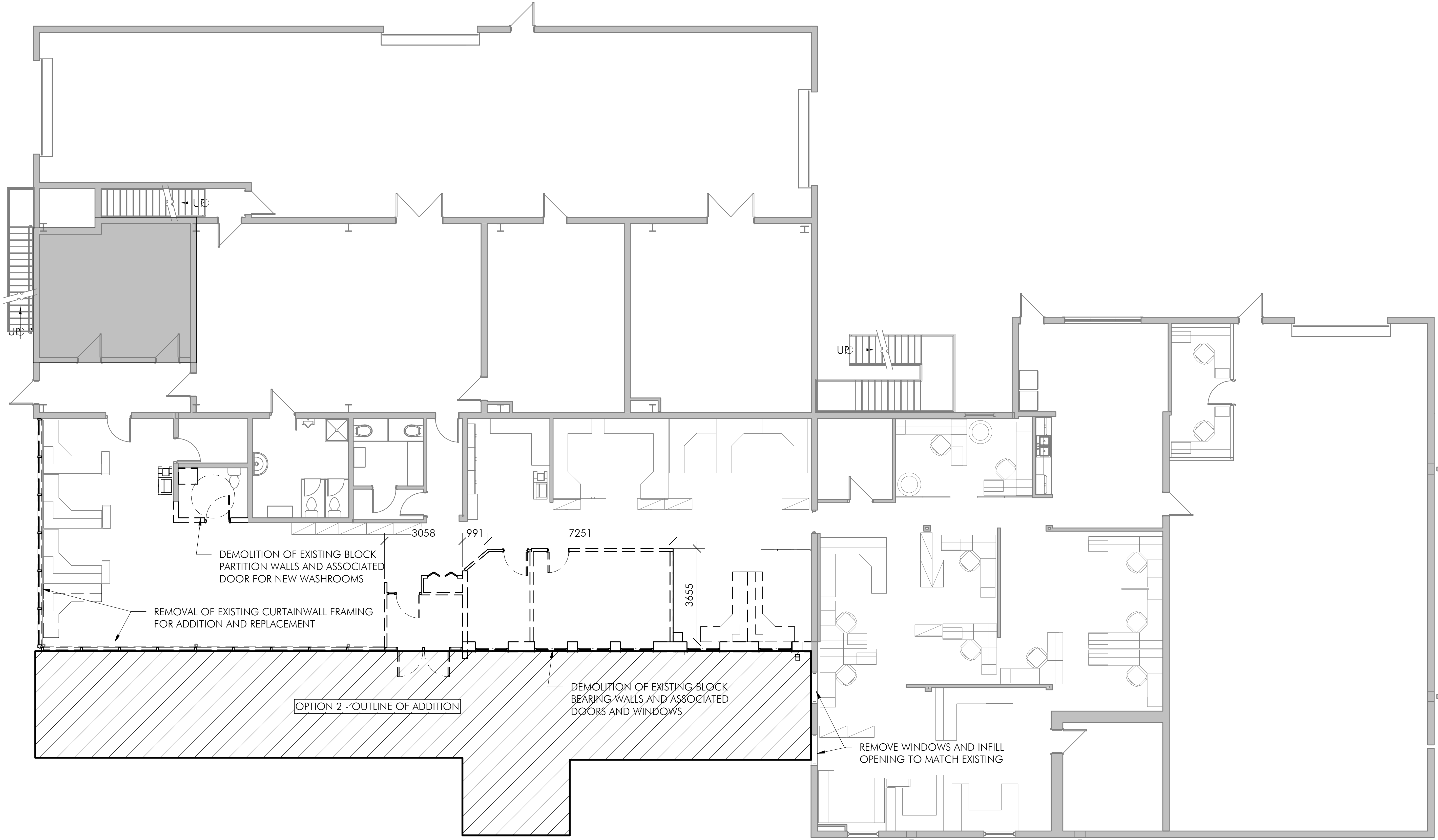
Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 2 - 3d Views

Project No: 2019047

SD.11

Date: 2019.10.09



139.6sm (1527sf)

Form Studio Architects Inc.

HYDRO ONE - REMOTE COMMUNITIES • OFFICE ADDITION
Option 2 - Demolition Plan

Project No: 2019047

SD.16

Date: 2019.10.09

ATTACHMENT 2:

COST ESTIMATES

305-93 Lombard Ave.
Winnipeg, MB R3B 3B1
Phone: (204) 415-3700
Email: pqs@shaw.ca
www.postmaquantitysurveying.ca

October 31, 2019

Form Studio Architecture
131 Court Street North
Thunder Bay, Ont.
P7A 4V1

Attention: Matthew Mills

Re: **Hydro One Remote Communities Office Renovations and Addition**
Thunder Bay, Ont.
Class D Estimates

We are pleased to attach our class D estimate for the above noted project and do hereby certify the following values as noted below which include a 15% design contingency.

- Option 1b $712,610.00
- Option 2 $935,900.00

The estimate excludes, contingency allowances, hazardous abatement, HST, furniture and any consulting fees. The pricing reflects probable construction costs obtainable in the location of the project as of the date of this estimate and is a determination of fair market value for the construction of this project and should not be taken as a prediction of low bid.

This pricing assumes competitive bidding for every portion of the construction work including all subcontractors as well as the general contractor and assumes a minimum of four (4) general bidders. If fewer bids are received, the bid results can be expected to be higher.

It is recognized, however, that Postma Quantity Surveying does not have control over the cost of labour, material or equipment, over a contractor's methods of determining bid prices, or over competitive bidding, market or negotiation conditions.

Accordingly, Postma Quantity Surveying cannot and does not warrant or represent that bids or negotiated prices will not vary from this or any subsequent estimate of construction cost or evaluation prepared or agreed to by Postma Quantity Surveying. It is generally acknowledged that a Class D estimate is within the range of plus or minus twenty (20%) percent.

We hope this meets to your satisfaction. If you have any questions, please do not hesitate to call.

POSTMA QUANTITY SURVEYING LTD.

Wesley Pst

Wes Postma, PQS, CET, GSC
President

Hydro One Remote Communities, Thunder Bay, Ont option 1 b

Class D Estimate 10/31/2019

Postma Quanitity Surveying Ltd.

	Descripton of Work Building	Unit	Quantity Building	Unit Price	Total Building
1	**General Conditions**				
2	Supervision, site administration - 2 phases	month	7	$9,000.00	$63,000
3	Indirect Site Costs - 2 phases	month	7	$3,600.00	$25,200
4	Overhead & Fee GC	%	7.00	$580,000	$40,600
5	Bonds & Insurance, permits	thous.	620	$25.00	$15,500
6	Cash Allowances - testing & inspections	item	$ 1.00	$0.00	none shown
7				Subtotal	$144,300
8	**Site work & demolition**				
9	Strip asphalt & man door conc pad	sm	110	$20.00	$2,200
10	Excavate to underside of gravel base at SOG	m3	38	$40.00	$1,520
11	Excavate foundation wall and footing	m3	71	$21.00	$1,491
12	Backfill walls with gravel	m3	82	$75.00	$6,150
13	New concrete mandoor pad	m2	17	$170.00	$2,890
14	Weeping tile at footings	m	32	$50.00	$1,600
15	New conc curb	m	30	$60.00	$1,800
16	Site sod repairs	sm	10	$50.00	$500
17	Asphalt repair	m2	25	$42.00	$1,050
18	Remove vestibule coat closet walls/doors	ea	1	$50.00	$50
19	Remove part masonry wall w\r	sm	7	$50.00	$350
20	Remove exist'g w/r fr/dr	ea	1	$60.00	$60
21	Remove alum/glass vestibule	sm	12	$30.00	$360
22	Haul demo off site	loads	1	$450.00	$450
23	Remove alum fr/drs-	pr	1	$250.00	$250
24	Remove curtainwall framing for add & replacement	sm	60	$53.00	$3,180
25				Subtotal	$23,901
26	**Structural Elements**				
27	Continous Concrete footings 32 LM	m3	5	$925.00	$4,625
28	Concrete walls on footing	m3	13	$1,150.00	$14,950
29	Rebar	kg	6500	$2.40	$15,600
30	St columns 9 thus 3.6 h 150 sq.HSS	kg	1,275	$11.00	$14,025
31	C 200x38 roof beam	kg	1,212	$11.00	$13,332
32	OWSJ 3@7500,12@4.4 and steel deck	m2	110	$107.00	$11,770
33	C or girt to support curtainwall sill	lm	22	$32.00	$704
34				Subtotal	$75,006
35	**Rough Carpentry, Architectural Woodwork, Misc metal**				
36	Rough carpentry- misc blocking,roof & window	item	1	$4,200.00	$4,200
37	Window sills	m	22	$75.00	$1,650
38	Cabinets upper incl mail slots	m	0	$500.00	none shown
39	Cabinets lower	m	0	$1,000.00	none shown
40	Allow modular furniture	station	12	$4,000.00	with FF&E
41				Subtotal	$5,850
42	**Insulation, AVB, Roofing, siding, stone**				
43	Dampproofing foundation wall	m2	48	$8.00	$384
44	102 mm rigid at grade beam	m2	48	$68.00	$3,264
45	Roof single ply membr. R-40	m2	110	$210.00	$23,100
46	Fascia at canopy/roof/trim	lm	64	$40.00	$2,560
47	vert.mt clad,Z bar,R-30 rigid,blueskin	m2	51	$160.00	$8,160
48	canopy wd log post, timber roof framing w mt brackets	lm	28	$68.00	$1,904

Hydro One Remote Communities, Thunder Bay, Ont option 1 b

Class D Estimate 10/31/2019

Postma Quanitity Surveying Ltd.

	Descripton of Work Building	Unit	Quantity Building	Unit Price	Total Building
49	wood soffit	m2	17	$65.00	$1,105
50	Canopy roof w fascia-non insul -red	m2	28	$110.00	$3,080
51	Insul canopy walls red ?	m2	35	$160.00	$5,600
52	75 rigid frost protection backfill	m2	40	$43.00	$1,720
53	Downspouts with splash pads	no	3	$175.00	$525
54	Firestopping	item	1	$400.00	$400
55				Subtotal	$51,802
56	**Doors & windows**				
57	Quiet rm fr/dr/hard'w	no	1	$1,000.00	$1,000
58	Universal w/r fr/dr/hard'w	no	1	$900.00	$900
59	curtainwall or storefront 22 x1.8 h	sm	40	$750.00	$30,000
60	Auto operator	no	2	$2,500.00	$5,000
61	Aluminum entrance with sidelights/transom 10 sm	no	1	$11,000.00	$11,000
62	Interior standard vest entry alum fr/drs	pr	1	$3,500.00	$3,500
63	Exterior windows- Alum 2@ 1 x1.5	m2	3	$850.00	$2,550
64				Subtotal	$53,950
65	**Drywall, Acoustic Ceilings, Flooring, Painting**				
66	int-16mm drywall/SS walls-quiet,w/r ,vestibule insul	m2	98	$28.00	$2,744
67	16mm /SS to ext wall 29 x 3.6 less glass	m2	52	$60.00	$3,120
68	Cut & patch drywall for m/e, misc-rw/r ceiling	m2	10	$11.00	$110
69	Drywall ceilings incl vestibule	m2	110	$45.00	$4,950
70	Drywall bulkhead at new/replace window framing	lm	23	$75.00	$1,725
71	Acoustic tile ceil in addition, minor patch in exist'g	sm	102	$55.00	$5,610
72	New flooring - carpet tile	m2	102	$50.00	$5,100
73	Porcelain tile w/r and vest	m2	32	$180.00	$5,760
74	Vinyl base	m	51	$8.00	$408
75	Painting	m2	110	$35.00	$3,850
76				Subtotal	$33,377
77	**Specialties**				
78	Washroom Accessories	item	1	$1,500.00	$1,500
79	Window blinds -Allow	item	1	$3,000.00	$3,000
80				Subtotal	$4,500
81	**Mechanical**				
82	Mechanical as per attached worksheets	item	1	$129,370.00	$129,370
83				Subtotal	$129,370
84	**Electrical**				
85	Electrical as per worksheet attached	item	1	$97,605.00	$97,605
86				Subtotal	$97,605
87	**Subtotal**				$619,661
88	Escalation			0.00%	$0
89	**SUBTOTAL**				$619,661
90	Design contingency			15.00%	$92,949
91	**TOTAL**				**$712,610**

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 1b		1	m2		
C1 Mechanical						
C11 Plumbing & Drainage						
1	Fixture		1	m2	3,300.00	3,300
	Water closet		1	ea.	800.00	800
	Water closet Barrier free		1	ea.	900.00	900
	Lavatory		1	ea.	750.00	750
	Lavatory Barrier free		1	ea.	850.00	850
2	Domestic Water		1	m2	6,500.00	6,500
	Connect to existing		1	no	500.00	500
	Domestic water pipe		1	sum	3,500.00	3,500
	Thermal pipe insulation		1	sum	1,500.00	1,500
	Fixture rough in		4	ea.	250.00	1,000
3	Sanitary Waste and Vents		1	m2	8,150.00	8,150
	Connect to existing		1	no	500.00	500
	Sanitary drain - below grade		1	sum	2,000.00	2,000
	Sanitary vents - above grade		1	sum	2,000.00	2,000
	Floor drain		2	no	200.00	400
	Fixture rough in		4	ea.	250.00	1,000
	Concrete cut and patch		1	sum	1,500.00	1,500
	Excavation and backfill		1	sum	750.00	750
4	Natural gas		1	m2	1,700.00	1,700
	Disconnect and reconnect RTU		2	no	850.00	1,700
5	Demolition		1	m2	500.00	500
	Remove fixture c/w drains and water pipe		2	no	250.00	500
	C11 Plumbing & Drainage	Total : $	1	m2	20,150.00	20,150
C12 Fire Protection						
1	Fire extinguisher		1	m2	400.00	400
	Wall hung extinguisher		2	no	200.00	400
	C12 Fire Protection	Total : $	1	m2	400.00	400

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 1b		1	m2		
C13 HVAC						
1	Air handling units and fans		1	m2	25,350.00	25,350
	Roof top unit - gas heating - package cooling 7.5 ton		2	ea.	12,500.00	25,000
	Washroom exhaust		1	no	350.00	350
2	Air distribution ductwork & devices		1	m2	50,970.00	50,970
	Galvanized ductwork		1200	kg	20.00	24,000
	Thermal insulation		250	sm	30.00	7,500
	Acoustic insulation		100	sm	45.00	4,500
	VAV box		1	ea.	1,000.00	1,000
	VAV box c/w re-heat coil		5	ea.	1,500.00	7,500
	Supply diffuser		16	ea.	225.00	3,600
	Return grill		12	ea.	185.00	2,220
	Exhaust grill		2	ea.	175.00	350
	Wall box		1	ea.	300.00	300
3	Balancing & commissioning		1	m2	2,750.00	2,750
	Air balancing		1	sum	2,000.00	2,000
	TAB		1	sum	750.00	750
4	Demolition		1	m2	5,000.00	5,000
	Remove existing Roof top unit		2	no	2,500.00	5,000
	C13 HVAC	Total : $	1	m2	84,070.00	84,070
C14 Controls						
1	Controls		1	m2	24,750.00	24,750
	Roof top unit		2	no	1,500.00	3,000
	VAV box		6	no	1,000.00	6,000
	Exhaust fan timer		1	no	750.00	750
	Electric re-heat coil		5	no	1,000.00	5,000
	BAS control		1	sum	10,000.00	10,000
	C14 Controls	Total : $	1	m2	24,750.00	24,750
	Mechanical	Total : $	1	m2	129,370.00	129,370

	Building Area - Option 1b		1	m2		
C2 Electrical						
C21 Service and Distribution			1	m2	5,750.00	5,750
1	New panel from existing		1	no	2,500.00	2,500
2	Feeders					
	- panel feeder		100	ft	25.00	2,500
3	Testing		1	sum	500.00	500
4	Grounding		1	sum	250.00	250
C21 Service and Distribution		Total	1	m2	5,750.00	5,750
C22 Lighting, devices and heating						
1	Light fixtures		1	m2	38,150.00	38,150
	Fixture type 2 by 4		30	no	500.00	15,000
	Fixture type pot		6	no	250.00	1,500
	Fixture type exterior wall		4	no	450.00	1,800
	Emergency double head		10	no	200.00	2,000
	Exit sign		4	no	450.00	1,800
	Single Pole switch / motion		2	no	125.00	250
	Occupancy sensor		8	no	350.00	2,800
	Lighting branch wiring		1	no	12,500.00	12,500
	Lighting demolition - remove fixture		10	no	50.00	500
2	Power outlets, devices and connections		1	m2	22,555.00	22,555
	Duplex receptacle 15A		40	no	125.00	5,000
	Duplex receptacle 20A		2	no	130.00	260
	Duplex receptacle USB		2	no	135.00	270
	Duplex receptacle GFI		2	no	140.00	280
	Duplex receptacle GFI WP		1	no	145.00	145
	Barrier free door operator		2	no	550.00	1,100
	Hand dryer		2	no	750.00	1,500
	Branch wiring		1	sum	12,500.00	12,500
	Power demolition		1	sum	1,500.00	1,500

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 1b		1	m2		
3	Mechanical equipment connection		1	m2	7,250.00	7,250
	Roof top unit		2	no	1,500.00	3,000
	Exhaust fan		1	no	150.00	150
	VAV		6	no	100.00	600
	Branch wiring		1	sum	3,500.00	3,500
4	Electric Heating		2	m2	2,250.00	4,500
	Force Flow		2	no	850.00	1,700
	Baseboard heater		2	no	350.00	700
	Connection		4	no	150.00	600
	Branch wiring		1	sum	1,500.00	1,500
	C22 Lighting, devices & heating	Total	1	m2	72,455.00	72,455

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 1b	1	m2		
C23 Systems & Ancillaries					
1	Fire alarm	1	m2	9,600.00	9,600
	Connect to existing fire alarm panel	1	no	1,500.00	1,500
	Horn/strobe	3	no	550.00	1,650
	Detector - smoke / thermal	5	no	350.00	1,750
	Pull station	1	no	200.00	200
	Wiring	1	sum	3,500.00	3,500
	Verification	1	sum	1,000.00	1,000
2	Communication	1	m2	6,500.00	6,500
	New terminal strip and rack	1	sum	1,000.00	1,000
	Data outlet	20	no	100.00	2,000
	Conduit and wiring	1	sum	3,500.00	3,500
3	Security	1	m2	3,300.00	3,300
	Connect to existing system	1	sum	500.00	500
	Motion detector	4	no	450.00	1,800
	Conduit and wiring	1	sum	1,000.00	1,000
	C23 Systems & Ancillaries	1	m2	19,400.00	19,400
	Electrical Total : $	1	m2	97,605.00	97,605

Hydro One Remote Communities, Thunder Bay, Ont. option 2

Class D Estimate 10/31/2019

Postma Quanitity Surveying Ltd.

	Descripton of Work Building	Unit	Quantity Building	Unit Price	Total Building
1	**General Conditions**				
2	Supervision, site administration	month	7	$9,000.00	$63,000
3	Indirect Site Costs	month	7	$3,600.00	$25,200
4	Overhead & Fee GC	%	7.00	$760,585	$53,241
5	Bonds & Insurance, permits	thous.	807	$25.00	$20,175
6	Cash Allowances - testing & inspections	item	$ 1.00	$0.00	none shown
7				Subtotal	$161,616
8	**Site work & demolition**				
9	Strip asphalt & man door conc pad	sm	134	$20.00	$1,650
10	Excavate to underside of gravel base at SOG	m3	50	$40.00	$2,000
11	Excavate foundation wall and footing	m3	92	$21.00	$1,932
12	Backfill walls with gravel	m3	107	$75.00	$8,025
13	New concrete mandoor pad	m2	6	$170.00	$1,020
14	Weeping tile at footings	m	46	$50.00	$2,300
15	New conc curb	m	44	$60.00	$2,640
16	Site sod repairs	sm	10	$50.00	$500
17	Asphalt repair	m2	60	$42.00	$2,520
18	Remove vestibule coat closet walls/doors	ea	1	$50.00	$50
19	Remove part masonry wall w\r	sm	7	$50.00	$350
20	Strip w/r walls,flooring	sm	18	$12.00	$216
21	Remove dw partitions 25 LM	sm	90	$15.00	$1,350
22	Remove exist'g fr/drs	ea	4	$60.00	$240
23	Remove alum/glass vestibule w doors	sm	12	$45.00	$540
24	Remove alum windows- in masonry wall	ea	8	$80.00	$640
25	Shore 9 LM roof bm,demo masonry wall	sm	34	$84.00	$2,856
26	Remove curtainwall framing for add & replacement	sm	114	$40.00	$4,560
27	Hoarding for wall and window removal	sm	150	$30.00	$4,500
28	haul masonry rubble	load	1	$450.00	$450
29	load/haul windows,dw,etc incl binage	loads	4	$650.00	$2,600
30				Subtotal	$40,939
31	**Structural Elements**				
32	Continous Concrete footings 32 LM	m3	7	$925.00	$6,475
33	Concrete walls on footing	m3	17	$1,150.00	$19,550
34	Rebar	kg	8400	$2.40	$20,160
35	canopy roof fram'g- WF 250x38x23 lm,C150x27x20 lm	kg	1414	$11.00	$15,554
36	St columns 13 thus 3.6 h 150 sq.HSS	kg	1,842	$11.00	$20,262
37	C 200x38 roof beam 41 LM	kg	1,558	$11.00	$17,138
38	OWSJ 3@7500,17@4.4 and steel deck	m2	134	$107.00	$14,338
39	canopy steel deck	sm	26	$30.00	$780
40	C or girt to support curtainwall sill	lm	31	$32.00	$992
41	Masonry infill removed windows	ea	2	$800.00	$1,600
42				Subtotal	$116,849
43	**Rough Carpentry, Architectural Woodwork, Misc metal**				
44	Rough carpentry- misc blocking,roof & window	item	1	$4,200.00	$4,200
45	Window sills	m	40	$75.00	$3,000
46	Allow modular furniture	station	9	$4,000.00	with FF&E
47				Subtotal	$7,200
48	**Insulation, AVB, Roofing, siding, stone**				
49	Dampfroofing foundation wall	m2	68	$8.00	$544
50	102 mm rigid at grade beam	m2	68	$68.00	$4,624
51	single ply membr. R-40, incl 26 SM canopy	m2	160	$210.00	$33,600
52	Fascia at canopy/roof/trim	lm	64	$40.00	$2,560

Hydro One Remote Communities, Thunder Bay, Ont. option 2

Class D Estimate 10/31/2019

Postma Quanitity Surveying Ltd.

	Descripton of Work Building	Unit	Quantity Building	Unit Price	Total Building
53	Vert.mt clad,Z bar,R-30 rigid,blueskin	m2	123	$160.00	$19,680
54	Canopy- red soffit 15 SM,fascia 15 LM	m2	30	$110.00	$3,300
55	Soffit or trim top of continous windows/vestibule	lm	50	$32.00	$1,600
56	75 rigid frost protection backfill	m2	51	$43.00	$2,193
57				Subtotal	$68,101
58	**Doors & windows**				
59	frame/door w sidelite,glazing,hard'w	no	3	$1,600.00	$4,800
60	interior PS borrowed lite frame/glazing 2 ea 2100x1500	sm	6	$240.00	$1,512
61	Universal w/r fr/dr/hard'w	no	1	$900.00	$900
62	curtainwall or storefront 33 x1.8 h	sm	60	$750.00	$45,000
63	Auto operator	no	2	$2,500.00	$5,000
64	Ext Curtainwall 3 sided w pr drs 10.4 LMx 3 M h	sm	31	$1,000.00	$31,000
65	Interior vest entry alum fr/drs, sidelites/transom 10 SM	pr	1	$7,500.00	$7,500
66	Employee room fr/dr/hard'w	ea	1	$900.00	$900
67	closet door/frame 600 mm w shelf	ea	1	$550.00	$550
68				Subtotal	$97,162
69	**Drywall, Acoustic Ceilings, Flooring, Painting**				
70	int-16mm drywall/SS walls-quiet,w/r ,vestibule insul	m2	124	$28.00	$3,472
71	16mm /SS DW to ext wall	m2	123	$60.00	$7,380
72	Cut & patch drywall for m/e, misc-rw/r ceiling	m2	6	$40.00	$240
73	Drywall ceilings - vestibule	m2	13	$45.00	$585
74	Drywall bulkhead at new/replace window framing	lm	37	$65.00	$2,405
75	New - carpet tile,addition 121, & renov 94 SM	m2	215	$50.00	$10,750
76	Acoustic ceilings - 134 SMaddition & 81 sm patch	m2	215	$55.00	$11,825
77	Porcelain tile w/r and vest	m2	31	$180.00	$5,580
78	Vinyl base	m	144	$8.00	$1,152
79	Painting addition,renov	m2	215	$35.00	$7,525
80				Subtotal	$50,914
81	**Specialties**				
82	Washroom Accessories	item	1	$1,500.00	$1,500
83	Window blinds -Allow	item	1	$3,000.00	$3,000
84				Subtotal	$4,500
85	**Mechanical**				
86	Mechanical as per attached worksheets	item	1	$150,160.00	$150,160
87				Subtotal	$150,160
88	**Electrical**				
89	Electrical as per worksheet attached	item	1	$116,385.00	$116,385
90				Subtotal	$116,385
91	**Subtotal**				$813,826
92	Escalation			0.00%	$0
93	**SUBTOTAL**				$813,826
94	Design contingency			15.00%	$122,074
95	**TOTAL**				**$935,900**

QSM Mechanical Quantity Surveying 30-Oct-19
Hydro One Remote Locations Office
Class D Estimate

	Building Area - Option 2		1	m2		
C1 Mechanical						
C11 Plumbing & Drainage						
1	Fixture		1	m2	3,300.00	3,300
	Water closet		1	ea.	800.00	800
	Water closet Barrier free		1	ea.	900.00	900
	Lavatory		1	ea.	750.00	750
	Lavatory Barrier free		1	ea.	850.00	850
2	Domestic Water		1	m2	6,500.00	6,500
	Connect to existing		1	no	500.00	500
	Domestic water pipe		1	sum	3,500.00	3,500
	Thermal pipe insulation		1	sum	1,500.00	1,500
	Fixture rough in		4	ea.	250.00	1,000
3	Sanitary Waste and Vents		1	m2	8,150.00	8,150
	Connect to existing		1	no	500.00	500
	Sanitary drain - below grade		1	sum	2,000.00	2,000
	Sanitary vents - above grade		1	sum	2,000.00	2,000
	Floor drain		2	no	200.00	400
	Fixture rough in		4	ea.	250.00	1,000
	Concrete cut and patch		1	sum	1,500.00	1,500
	Excavation and backfill		1	sum	750.00	750
4	Natural gas		1	m2	1,700.00	1,700
	Disconnect and reconnect RTU		2	no	850.00	1,700
5	Demolition		1	m2	500.00	500
	Remove fixture c/w drains and water pipe		2	no	250.00	500
	C11 Plumbing & Drainage	Total : $	1	m2	20,150.00	20,150
C12 Fire Protection						
1	Fire extinguisher		1	m2	400.00	400
	Wall hung extinguisher		2	no	200.00	400
	C12 Fire Protection	Total : $	1	m2	400.00	400

C13 HVAC

1	Air handling units and fans		1	m2	25,350.00	25,350
	Roof top unit - gas heating - package cooling 7.5 ton		2	ea.	12,500.00	25,000
	Washroom exhaust		1	no	350.00	350
2	Air distribution ductwork & devices		1	m2	67,260.00	67,260
	Galvanized ductwork		1600	kg	20.00	32,000
	Thermal insulation		300	sm	30.00	9,000
	Acoustic insulation		150	sm	45.00	6,750
	VAV box		3	ea.	1,000.00	3,000
	VAV box c/w re-heat coil		5	ea.	1,500.00	7,500
	Supply diffuser		24	ea.	225.00	5,400
	Return grill		16	ea.	185.00	2,960
	Exhaust grill		2	ea.	175.00	350
	Wall box		1	ea.	300.00	300
3	Balancing & commissioning		1	m2	3,250.00	3,250
	Air balancing		1	sum	2,500.00	2,500
	TAB		1	sum	750.00	750
4	Demolition		1	m2	5,000.00	5,000
	Remove existing Roof top unit		2	no	2,500.00	5,000
	C13 HVAC	Total : $	1	m2	100,860.00	100,860

C14 Controls

1	Controls		1	m2	28,750.00	28,750
	Roof top unit		2	no	1,500.00	3,000
	VAV box		8	no	1,000.00	8,000
	Exhaust fan timer		1	no	750.00	750
	Electric re-heat coil		5	no	1,000.00	5,000
	BAS control		1	sum	12,000.00	12,000
	C14 Controls	Total : $	1	m2	28,750.00	28,750
	Mechanical	Total : $	1	m2	150,160.00	150,160

	Building Area - Option 2		1	m2		
C2 Electrical						
C21 Service and Distribution			1	m2	5,750.00	5,750
1	New panel from existing		1	no	2,500.00	2,500
2	Feeders					
	- panel feeder		100	ft	25.00	2,500
3	Testing		1	sum	500.00	500
4	Grounding		1	sum	250.00	250
C21 Service and Distribution		Total	1	m2	5,750.00	5,750
C22 Lighting, devices and heating						
1	Light fixtures		1	m2	47,950.00	47,950
	Fixture type 2 by 4		40	no	500.00	20,000
	Fixture type pot		6	no	250.00	1,500
	Fixture type exterior wall		5	no	450.00	2,250
	Emergency double head		12	no	200.00	2,400
	Exit sign		5	no	450.00	2,250
	Single Pole switch / motion		2	no	125.00	250
	Occupancy sensor		10	no	350.00	3,500
	Lighting branch wiring		1	no	15,000.00	15,000
	Lighting demolition - remove fixture		16	no	50.00	800
2	Power outlets, devices and connections		1	m2	26,935.00	26,935
	Duplex receptacle 15A		50	no	125.00	6,250
	Duplex receptacle 20A		3	no	130.00	390
	Duplex receptacle USB		2	no	135.00	270
	Duplex receptacle GFI		2	no	140.00	280
	Duplex receptacle GFI WP		1	no	145.00	145
	Barrier free door operator		2	no	550.00	1,100
	Hand dryer		2	no	750.00	1,500
	Branch wiring		1	sum	15,000.00	15,000
	Power demolition		1	sum	2,000.00	2,000

3	Mechanical equipment connection		1	m2	7,450.00	7,450
	Roof top unit		2	no	1,500.00	3,000
	Exhaust fan		1	no	150.00	150
	VAV		8	no	100.00	800
	Branch wiring		1	sum	3,500.00	3,500
4	Electric Heating		2	m2	2,250.00	4,500
	Force Flow		2	no	850.00	1,700
	Baseboard heater		2	no	350.00	700
	Connection		4	no	150.00	600
	Branch wiring		1	sum	1,500.00	1,500
	C22 Lighting, devices & heating	Total	1	m2	86,835.00	86,835
C23 Systems & Ancillaries						
1	Fire alarm		1	m2	11,500.00	11,500
	Connect to existing fire alarm panel		1	no	1,500.00	1,500
	Horn/strobe		4	no	550.00	2,200
	Detector - smoke / thermal		6	no	350.00	2,100
	Pull station		1	no	200.00	200
	Wiring		1	sum	4,500.00	4,500
	Verification		1	sum	1,000.00	1,000
2	Communication		1	m2	9,000.00	9,000
	New terminal strip and rack		1	sum	1,000.00	1,000
	Data outlet		30	no	100.00	3,000
	Conduit and wiring		1	sum	5,000.00	5,000
3	Security		1	m2	3,300.00	3,300
	Connect to existing system		1	sum	500.00	500
	Motion detector		4	no	450.00	1,800
	Conduit and wiring		1	sum	1,000.00	1,000
	C23 Systems & Ancillaries		1	m2	23,800.00	23,800
	Electrical	Total : $	1	m2	116,385.00	116,385

ATTACHMENT 3:

PROPERTY APPRAISAL OF 680 BEAVERHALL PLACE

Property Appraisal Of

680 Beaverhall Place
Thunder Bay

Prepared For

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

ANDREW, THOMPSON & ASSOCIATES LTD.

ANDREW, THOMPSON & ASSOCIATES LTD.

177 Dunlop Street West
Barrie, ON L4N 1B4
PHONE 705-721-1596 FAX 705-721-5183
WEB www.andrew-thompson.on.ca

August 17, 2021

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

Attention: Mr. Keith Barr

Re: 680 Beaverhall Place, Thunder Bay

Dear Mr. Barr:

At your request, we provide this report describing our investigation and analysis of the above referenced property, as of July 28, 2021. We understand the purpose of this report is to estimate market value. The intended use is to assist with an asset review. This report is to be relied upon by the client only unless otherwise stated. The property rights appraised in this report are the fee simple ownership, assuming the title to be free and clear of all encumbrances, unless otherwise stated. This report should be read in its entirety prior to making a decision to rely upon the report.

As a result of our investigation it is our professional opinion that the subject property in its Highest and Best Use as a continued industrial use has a current market value of $2,300,000,

TWO MILLION THREE HUNDRED THOUSAND DOLLARS

Any Extraordinary Assumptions, Hypothetical Conditions and/or Extraordinary Limiting Conditions are noted in Section 6.0.

As of the date of this report Canada and the Global Community is experiencing unprecedented measures undertaken by various levels of government to curtail health related impacts of the Covid-19 Pandemic. The duration of this event is not known. While there is potential for impacts with respect to micro and macro-economic sectors, as well as upon various real estate markets, it is not possible to predict such impact at present, or the impact of current and future government countermeasures. Accordingly, this point-in-time valuation assumes the continuation of current market conditions, and that current longer-term market conditions remain unchanged. Given the market uncertainties of the Covid-19 pandemic, a force majeure event, we reserve the right to revise the value estimation set out in this report for a fee, with an update appraisal report under a separate appraisal engagement, incorporating market information available at that time. Values contained in this appraisal are based on market conditions as at the time of this report. This appraisal does not provide a prediction of future values. In the event of market instability and/or disruption, values may change rapidly and such potential future events have NOT been considered in this report. As this appraisal does not and cannot consider any changes to the property appraised or market conditions after the effective date, readers are cautioned in relying on the appraisal after the effective date noted herein.

This current short narrative report is provided in a format that is consistent with the Terms of Reference and in accordance with the Canadian Uniform Standards of Professional Appraisal

Practice (C-USPAP) adopted by the Appraisal Institute of Canada.

We trust the information provided meets with your approval and thank you for considering our firm.

Respectfully Submitted,
ANDREW, THOMPSON AND ASSOCIATES LTD.

DRAFT

Peter Spivey, B.Sc, AACI, P.App

TABLE OF CONTENTS

1.0 Introduction

This report addresses the current market valuation of the Hydro One Remote Communities facility situated at 680 Beaverhall Place. The property is located in the Beaverhall Industrial Area, a concentration of industrial development located to the immediate east of the Thunder Bay International Airport.

The subject property represents a 2.82 acre parcel improved with a 15,570 sq.ft. office / service industrial building, a 4,065 sq.ft, cold storage warehouse, a 1,200 sq.ft. workshop and a number of small storage buildings. The main office / service industrial building is comprised of approximately 8,790 sq.ft. of office space and 6,780 sq.ft. of service shop, storage and shop office area. The site is fully graded and includes a rear gravel storage yard and a front paved parking lot.

Figure 1 Source: City of Thunder Bay GIS

2.0 Photographs of the Subject Property

Front View of Subject Building

Rear View of Subject Service Garage Area (Main Building)

Rear View of Main Building

View of Warehouse Building

View of Front Paved Parking Lot

View of Rear Yard Area

View of Workshop

Sheds / Yard Area

Neighbourhood View Looking South along Beaverhall Place

Neighbourhood View Looking North along Beaverhall Place

3.0 Executive Summary

Intended Users	Hydro One Remote Communities Inc.
Address	680 Beaverhall Place, Thunder Bay
Legal Description	Lot 13, Plan W796, (Neebing), City of Thunder Bay
PIN #	620430045
Registered Owner	Ontario Hydro
Effective Date	July 28, 2021
Inspection Date	July 28, 2021

3.1 Property:

Lot Size	2.82 acres	
Building GFA	Office / Service Industrial Building	15,570 sq.ft.
	Cold Storage Warehouse	4,065 sq.ft,
	Workshop	1,200 sq.ft.
	Total	20,835 sq.ft.
Official Plan Designation	Light Industrial	
Zoning	IN2 - Medium Industrial Zone	
Present Use	General Industrial	
Highest and Best Use		
Land as if Vacant	Development as a permitted industrial use.	
Improved	Continued industrial use as developed.	

3.2 Valuation:

Purpose and Intended Use of the Appraisal	To estimate the market value to assist with an asset review.	
Value Estimates	Cost Approach	$2,509,000
	Direct Comparison Approach	$2,188,000 to $2,396,000
Final Estimate of Market Value	**$2,300,000**	

Any Extraordinary Assumptions, Hypothetical Conditions and/or Extraordinary Limiting Conditions are noted in Section 6.0.

4.0 Basis of the Appraisal

Client – The Client for this file is Hydro One Remote Communities Inc.. We received our instructions from Mr. Keith Barr.

The Intended User(s) - This report is intended for use only by Hydro One Remote Communities Inc.. Use of this report by others is not intended by the member, and any liability in this respect is strictly denied. Should an additional user wish to rely on this report, the member requires the client's instructions in writing and the additional user requires a separate release letter from the member and under all other circumstances no liability is extended to third party users.

Purpose of the report - The purpose of this appraisal is to estimate the market value of the subject property as of July 28, 2021.

Intended use of the report - The intended use of this appraisal is to assist Hydro One Remote Communities Inc. with an asset review.

We have not applied a Jurisdictional Exception in the preparation of this report.

5.0 Terms of Reference

At the request of Hydro One Remote Communities Inc., Andrew, Thompson & Associates Ltd. was instructed to:

1. Undertake a Narrative Appraisal Report in accordance with the "Standards" (Canadian Uniform Standards of Professional Appraisal Practice, CUSPAP) of the Appraisal Institute of Canada.
2. Provide an independent and objective opinion.

There were no specific Terms of Reference (TOR) provided.

6.0 Extraordinary Assumptions, Hypothetical Conditions and Limiting Conditions

6.1 Extraordinary Assumptions

An extraordinary assumption refers to an assumption, directly related to a specific assignment, which, if found to be false, could materially alter the opinions or conclusions.

- None

6.2 Hypothetical Conditions

A hypothetical condition is that which is contrary to what exists, but is supposed to exist for the purpose of analysis.

- None

6.3 Extraordinary Limiting Condition

An extraordinary condition is a necessary modification or exclusion of a Standard Rule which may diminish the reliability of the report.

- As of the date of this report Canada and the Global Community is experiencing unprecedented measures undertaken by various levels of government to curtail health related impacts of the Covid-19 Pandemic. The duration of this event is not known. While there is potential for impacts with respect to micro and macro-economic sectors, as well as upon various real estate markets, it is not possible to predict such impact at present, or the impact of current and future government countermeasures. Accordingly, this point-in-time valuation assumes the continuation of current market conditions, and that current longer-term market conditions remain unchanged. Given the market uncertainties of the Covid-19 pandemic, a force majeure event, we reserve the right to revise the value estimation set out in this report for a fee, with an update appraisal report under a separate appraisal engagement, incorporating market information available at that time. Values contained in this appraisal are based on market conditions as at the time of this report. This appraisal does not provide a prediction of future values. In the event of market instability and/or disruption, values may change rapidly and such potential future events have NOT been considered in this report. As this appraisal does not and cannot consider any changes to the property appraised or market conditions after the effective date, readers are cautioned in relying on the appraisal after the effective date noted herein.

- In this instance the Income Approach has not been utilized. Although sometimes suitable, it appears that larger standalone industrial facilities such as the subject in the local market are in most instances' owner occupied and are not typically acquired as income producing properties. As such we have not applied an Income Approach in this instance.

7.0 Scope of Work Undertaken

Each appraisal assignment is different. Depending on the size, type and use the complexity may vary and the significance and level of research may also vary. The level of investigation that is appropriate for each appraisal problem is that level of care that the reasonable member would apply. In some cases, based on the client's needs and the intended use the focus of the engagement may require greater detail or verification.

The specific tasks considered necessary to complete this assignment were as follows:

7.1 Property / Site Observation

We observed the subject property on July 28, 2021. We were accompanied by Mr. Keith Barr and Mike Hartviksen on that date. The enclosed pictures were taken on this date unless otherwise stated.

With respect to the buildings we typically observe all unlocked and available rooms. Attics are not inspected unless requested or there is an observed condition that warranted the request for access to view the attic. Basements are observed where available and passable, crawl spaces are not observed. Roof reports are requested from the client at the outset of the assignment. Roofs are not inspected by the appraiser, however, are observed as possible. We do not accept liability or responsibility to report the condition or remaining useful life of a roof covering unless this specifically forms part of the Terms of Reference. Photography taken is where deemed required, permitted or requested. Electrical, mechanical, electronic, plumbing infrastructure and operations are not inspected and are assumed to meet the required building / fire code and in good operating condition except where otherwise noted.

The site is observed to the extent deemed reasonable depending on the site size, varying characteristics etc. No subsurface or surface tests are completed by the appraiser and no responsibility for below grade or unseen features, equipment or improvements form part of the inspection.

7.2 Review:

The following items **were considered**:

- Development trends, economic and real estate market conditions in relation to the subject existing as of the effective date; reviewed and analyzed the sales history of the subject.
- The physical, functional and economic characteristics for the subject property.
- Municipal data from various sources including government publications, municipal economic development departments and real estate publications.
- **Title Search**: It is assumed that the subject property was not subject to any encumbrances (mortgages, liens, etc) that would have negatively impacted the market value of the subject property as of the effective date. We have completed a parcel register search of the subject and examined relevant documents if noted in the property information section of this report.
- **Land Use Controls**: Publications produced by the local and regional municipality have been relied upon for land use controls including:
    - Official Plan(s)
    - Zoning By-laws
- Determined Municipal services available to the subject property.
- Considered and analyzed the Highest and Best Use of the property.
- After assembling and analysing the data, a final estimate of value was made.

- The valuation methods applied in this report arise from those determined to best address the specific type of property addressed in this analysis.
- We confirm that we saw no indication of environmental or contamination concerns at the date of our inspection unless further noted under the site description section of this report.

7.3 Data Research:

We have conducted market research with regard to comparable sales, in the Municipality and surrounding areas. We further gathered sales data obtained from sources including:

- Local Real Estate Board(s)
- Realtrack
- Geowarehouse/MPAC
- Review of internal files.
- Discussions with real estate agents and other members.
- Comparable sales have been confirmed by inspection, title review and/or interview with a party or agent to the sale when deemed necessary.

7.4 Third Party Information:

The analysis set out in this report relied upon written and verbal information obtained from a variety of sources considered reliable. Unless otherwise stated we did not verify client-supplied information, which we believed to be correct. The mandate for the appraisal did not require a report prepared to the standard appropriate for court purposes or for arbitration.

- The time and cost to confirm third party information can exceed reasonable appraisal budgets and accordingly this report relies upon written and verbal information provided from primary and hearsay sources. Client supplied information is assumed correct and was verified where possible. Any party relying upon this report should confirm with the member the source of important information and assumptions underlying the conclusions in our report.

7.5 Excluded Item(s) of Review

The following technical investigations **were not completed**:

- An environmental review or study of the subject property, including a historical use analysis;
- A site survey;
- Setback measurements;
- Investigation into bearing qualities of the soils;
- Subsurface qualities of the soil; percolation or other soil qualities; or;
- An archaeological review.
- With respect to the building we did not complete technical investigations such as detailed inspections or engineering review of the structure, roof or mechanical systems; an environmental review; audit of financial statements or other legal agreements; an investigation with the local fire department, building inspector, health department or any other government regulatory agency except as described in this report.

8.0 Appraisal Framework

8.1 Rights Appraised

Fee Simple is defined as absolute ownership by any other interest or estate, subject only to the limitations imposed by government powers of taxation, expropriation, police power and escheat. Leased Fee interests occurs when the property is encumbered by a lease. The valuation herein is based on the fee simple interest and assumes a 100% undivided interest.

8.2 Report Format

This current short narrative report is provided with regard to the rules and regulations as outlined in the prevailing CUSPAP.

The Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) outlines the standard rules as it relates to the development and communication of a formal opinion of value and identifies the minimum content necessary to produce a credible report that is not misleading.

An appraisal is a formal opinion of value that is: a) prepared as a result of a retainer; b) intended for reliance by identified parties; and c) for which the member assumes responsibility. This type of report must incorporate the minimum content necessary to produce a credible report that will not be misleading. The types of appraisal reports include; Narrative - either concise/short narrative reports or comprehensive / detailed reports and Form Reports - a standardized format combining check-off boxes and narrative comments.

Current Value – refers to an effective date contemporaneous with the date of the report, at the time of inspection or at some other date within a reasonably short period from the date of inspection when market conditions have not or are not expected to have changed.

9.0 Definitions

9.1 Definition of Market Value

The most probable price which a property should bring in a competitive and open market as of the specific date under all conditions requisite to a fair sale, the buyer and seller each acting prudently and knowledgeably, and assuming the price is not affected by undue stimulus.
Implicit in this definition is the consummation of a sale as of a specified date and the passing of title from seller to buyer under conditions whereby;

1. buyer and seller are typically motivated;
2. both parties are well informed or well advised, and acting in what they consider their best interests;
3. a reasonable time is allowed for exposure in the open market;
4. payment is made in terms of cash in Canadian Dollars or in terms of financial arrangements comparable thereto; and
5. the price represents the normal consideration for the property sold unaffected by special or creative financing or sales concessions granted by anyone associated with the sale.

9.2 Effective Date

The date at which the analyses, opinions and conclusions in an assignment may apply. The effective date may be different from the inspection date and/or the report date.

9.3 Jurisdictional Exception

An assignment condition that permits the member to disregard a part or parts of the Standards that are determined to be contrary to law or public policy in a given jurisdiction and only that part shall be void and of no force or effect in that jurisdiction.

9.4 Fee Simple Interest

The highest estate or absolute right in real property. This represents the highest rights and fewest limitations and is generally considered absolute ownership. However, this bundle of rights (the right to use, sell, lease, enter, give away, or to refrain from any of these rights in regard to property) is subject to various restrictions imposed by laws of governing bodies[1].

9.5 Member

A term used throughout CUSPAP referring to a designated member or candidate member.

9.6 Leased Fee Interest

When a property is encumbered by a lease its status changes and the rights of the owner are considered to be the leased fee, versus an unencumbered property which is referred to as fee simple interest.

9.7 Definition of Economic Rent

Economic rent is the reasonable rental expectancy of the property if it were available for lease as compared with similar space; as distinguished from contract rent.

[1] *"Real Estate Encyclopaedia", copyright OREA March, 1997, page 389*

9.8 Intangible Property (Assets)

Non physical assets, including but not limited to franchises, trademarks, patents, copyrights, goodwill, equities, mineral rights, securities, and contracts, as distinguished from physical assets such as facilities and equipment.

9.9 Assemblage

The merging of adjacent properties into one common ownership or use.
Note: If applicable to the subject valuation and assemblage impacts the value, this will be addressed in the neighbourhood or valuation section.

9.10 Lease

A legal agreement which grants right to use, occupy, or control all or part of a property, to another party, for a stated period of time based on the terms and covenants of the lease including, among other things, the rental rate.

9.11 Occupant

The occupant is described as the person who has the right to occupy a unit or space (e.g. rental apartment, condominium unit, residential dwelling, office space).

9.12 Chattel

A tangible and moveable item that is not a fixture may be personal property and may be included with the realty.

9.13 Client

The client is the individual or organization for whom the member renders professional services. The client is typically the intended user of the assignment.

9.14 Confidential Information

Information, not otherwise publicly available, provided in trust that the recipient will not disclose to a third party.

In accordance with the Personal Information Protection Electronic Documents Act (PIPEDA), the Appraiser sought and received the written approval of the client, a copy of which is on file at the member’s office, to take pictures of the exterior and interior of the building and the property. Information provided to the Appraiser has been held as confidential where instructed by the client. The Appraiser made every effort to avoid taking pictures of any personal information that would make the occupant identifiable, regardless of physical form or characteristics.

9.15 Intended User

The client and any other party, as identified by name, as a user of the professional services of the Member, based on communication between the Member and the client.

10.0 Property Information

10.1 Legal Description and Restrictions

Address	680 Beaverhall Place, Thunder Bay
Legal Description	Lot 13, Plan W796, (Neebing), City of Thunder Bay
PIN#	620430045
Registered Owner	Ontario Hydro (Title Search)
Easements	Nil
Right of Ways	Nil
Relevant Encumbrances	Nil
Title Search Completed	Yes – See Attached

10.2 Assessment Information

Roll #	580404020113001
2016 Assessed Value	$1,645,000
Comparison with Market Value	Understated – Based on a dated 2016 assessed value date.
Comment	Assessed Value does not equate to market value as defined in this report. Assessments are updated and revised periodically and with changes in use.

10.3 Subject History

Last Transfer:	
Instrument #	TBR299917
Transfer Price	$525,000
Purchase Date	September 26, 1988
Purchaser	Ontario Hydro
Relevant Listings:	According to the public record, the subject property has not sold in the past three years. There are no other known records of the subject property being offered for sale over the same period.

11.0 Land Use Controls

11.1 Official Plan

The Official Plan sets out the longer term vision for Land Use in any given area. The purpose of an Official Plan is to provide a formally adopted text of public policies and standards as guidelines for the future development of the community.

The subject property is designated as ***"Light Industrial"*** in the Official Plan.

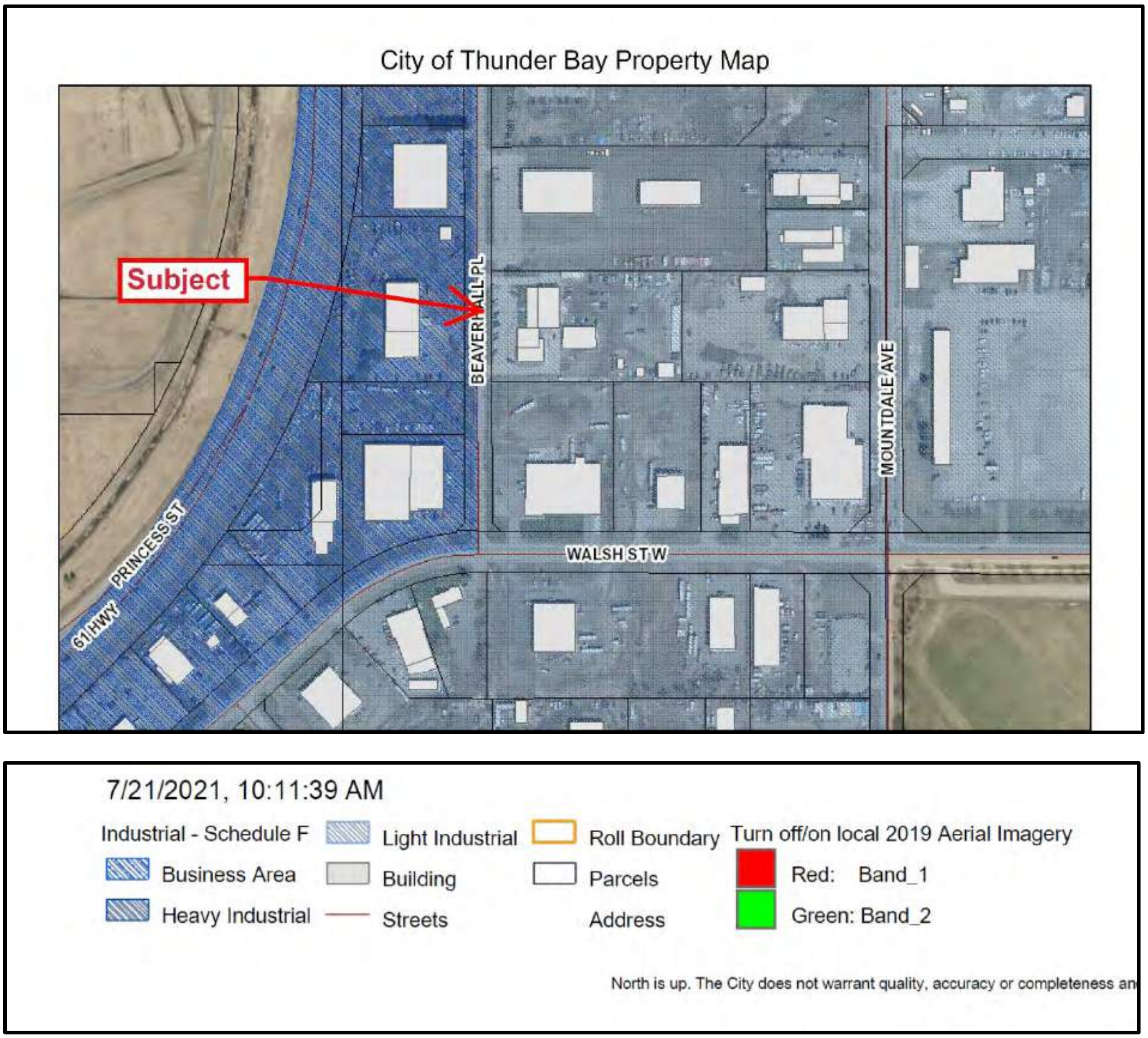


Figure 2 Source: City of Thunder Bay GIS

Official Plan - Light Industrial Policy Excerpt

LIGHT INDUSTRIAL

The intent of this designation is to provide for the development of a broad range of industrial activities which are likely to have a minimal impact on surrounding uses. Uses permitted may include the processing, treatment, storage, shipment, or manufacture of goods and materials. The operations of permitted industrial uses should be conducted substantially within enclosed buildings. Uses having similar characteristics will be encouraged to develop in clusters or on adjacent properties. Where practical, a gradation of uses may be encouraged so that those industries likely to have the least impact on neighbouring uses are directed to areas adjacent to other forms of development.

Development Standards

Areas designated as Light Industrial will, in most cases, be located where there is access to arterial roads, railways, and/or airport facilities, and where industrial traffic will be directed away from residential areas. Service facilities and storage areas shall be located in the rear yard or shall be fully screened from street view, only visitor parking shall be permitted in the front yard or exterior side yard.

11.2 Zoning

Zoning By-laws are a set of regulations governing land uses that implement the policies in the Official Plan. A Zoning By-law contains specific requirements that provides a way of managing land use and future development that is legally enforceable. It also protects property owners from conflicting land uses. Zoning By-laws cover such items as the use of land, where buildings and other structures may be located, the types of buildings that are permitted and how they may be used, lot sizes and dimensions, parking requirements, landscape and buffer requirements, building heights and setbacks from property lines.

According to the prevailing City of Thunder Bay Zoning By-law (ZBL), as amended, the subject property is zoned ***"IN2 - Medium Industrial Zone"***. The ZBL in effect at the effective date of valuation is understood to have been #100-2010.

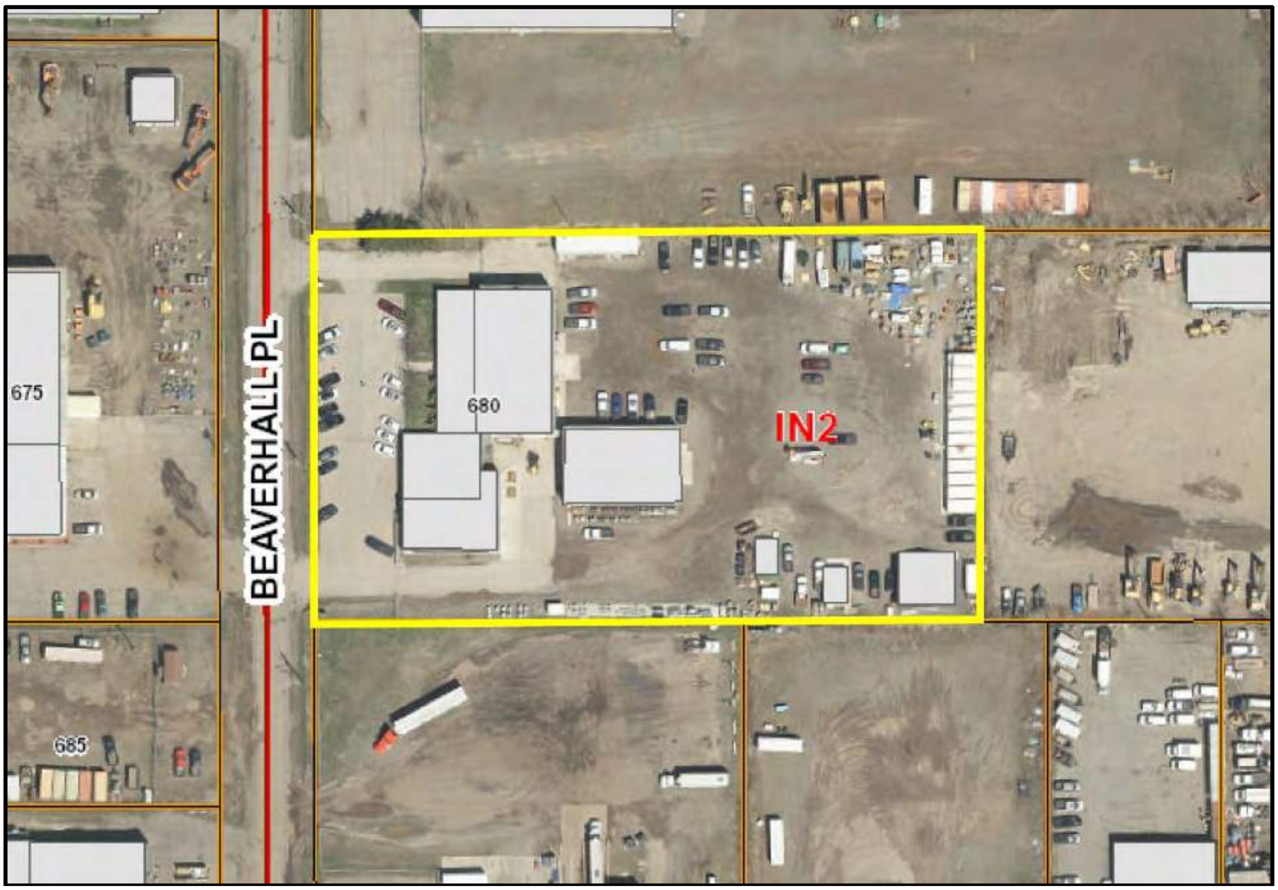


Figure 3 Source: City of Thunder Bay GIS

- ***Permitted Uses***

SECTION 27 **IN2 – MEDIUM INDUSTRIAL ZONE**

27.1 **a)** **Permitted USES**

No person shall use any land or erect or use any BUILDING or STRUCTURE within any IN2 ZONE for any purpose or USE other than the USES listed below:

- ANIMAL BOARDING FACILITY;
- ANIMAL CARE FACILITY;
- Car rental agency;
- EMERGENCY SERVICES FACILITY;
- EQUIPMENT SERVICE AND RENTAL ESTABLISHMENT;
- FUEL BAR;
- HOME IMPROVEMENT STORE;
- INDUSTRIAL CENTRE;
- INDUSTRIAL SCHOOL;
- LIGHT INDUSTRIAL USE;
- MEDIUM INDUSTRIAL USE;
- MOTOR VEHICLE SALES OR RENTAL ESTABLISHMENT;
- MOTOR VEHICLE SERVICE STATION;
- MOTOR VEHICLE BODY REPAIR SHOP;
- OUTDOOR STORAGE;
- PRIVATE UTILITY;
- RESTAURANT;
- SERVICE SHOP;
- TRANSPORT TERMINAL; or
- UTILITY.

b) **Additional Permitted USES:**

In addition to the USES permitted in Section 27.1(a), the following USES are permitted on LOTS with full MUNICIPAL SERVICES:

- Car Wash; or
- DRY-CLEANING PLANT.

- ***Regulations***

27.2 REGULATIONS

27.2.1 **Building Envelope REGULATIONS:** In addition to all other REGULATIONS of this BY-LAW, no person shall, within any IN2 ZONE, use any land, or erect or use any BUILDING or STRUCTURE, except in compliance with the building envelope REGULATIONS in Table 27.2.1.

To use the table, locate the applicable building envelope REGULATION in the first column of the table. Read across the table and locate the measurement in the same row as the applicable REGULATION that is within the column for the applicable type of LOT in question. The measurement in that table cell is the one that applies to the REGULATION in the first column and the type of LOT in question.

Table 27.2.1	LOTS WITH MUNICIPAL WATER SERVICES AND WITHOUT MUNICIPAL SEWAGE SERVICES	LOTS WITH MUNICIPAL SERVICES
Minimum REQUIRED LOT FRONTAGE	60.0m	22.0m
Minimum REQUIRED LOT AREA	10,000m^2	930.0m^2
Minimum REQUIRED FRONT YARD	9.0m	6.0m
Minimum REQUIRED REAR YARD	9.0m	6.0m
Minimum REQUIRED EXTERIOR SIDE YARD	6.0m	6.0m
Minimum REQUIRED INTERIOR SIDE YARD	3.0m	3.0m
Minimum LANDSCAPED OPEN SPACE	LANDSCAPED OPEN SPACE in the form of a 6.0 m wide strip along all LOT LINES abutting a RESIDENTIAL ZONE and LANDSCAPED OPEN SPACE in the form of a 3.0 m wide strip along all LOT LINES abutting a STREET LINE	LANDSCAPED OPEN SPACE in the form of a 6.0 m wide strip along all LOT LINES abutting a RESIDENTIAL ZONE and LANDSCAPED OPEN SPACE in the form of a 3.0 m wide strip along all LOT LINES abutting a STREET LINE
Maximum HEIGHT	15.0m	17.0m

27.2.2 **SEPARATION DISTANCE between MAIN BUILDINGS**

No person shall use any land or erect or use any BUILDING or STRUCTURE in an IN2 ZONE such that there is a SEPARATION DISTANCE of less than 6.0m between MAIN BUILDINGS on the LOT.

Table 1

Standard	IN2 – Medium Industrial	Subject Property
Lot Area (min.)	930 m2	Appears to Comply
Lot Frontage (min.)	22.0 m	Appears to Comply
Front Yard (min.)	6.0 m	Appears to Comply
Exterior Side Yard (min.)	6.0 m	Appears to Comply
Interior Side Yard (min.)	3.0 m	Appears to Comply
Rear Yard (min.)	9.0 m	May Not Comply to Workshop
Building Height (max.)	15.0 m	Appears to Comply

11.3 Summary

The land use, zoning and restrictions have not been confirmed with a municipal planner unless expressly stated. We have relied upon online documents through the municipal website or our internal library.

The subject appears to comply with the relevant Land Use regulations in terms of use. The subject appears to comply with most relevant Land Use regulations in terms of restrictions. The setback of the workshop appears to be slightly under the required 9.0m rear yard setback. Also, the separation distance of the main building to the warehouse is under the required 6.0 metres. The subject property is an existing facility and we do not expect these items to affect the continued use of the property.

12.0 Area and Neighbourhood Data

12.1 General Area

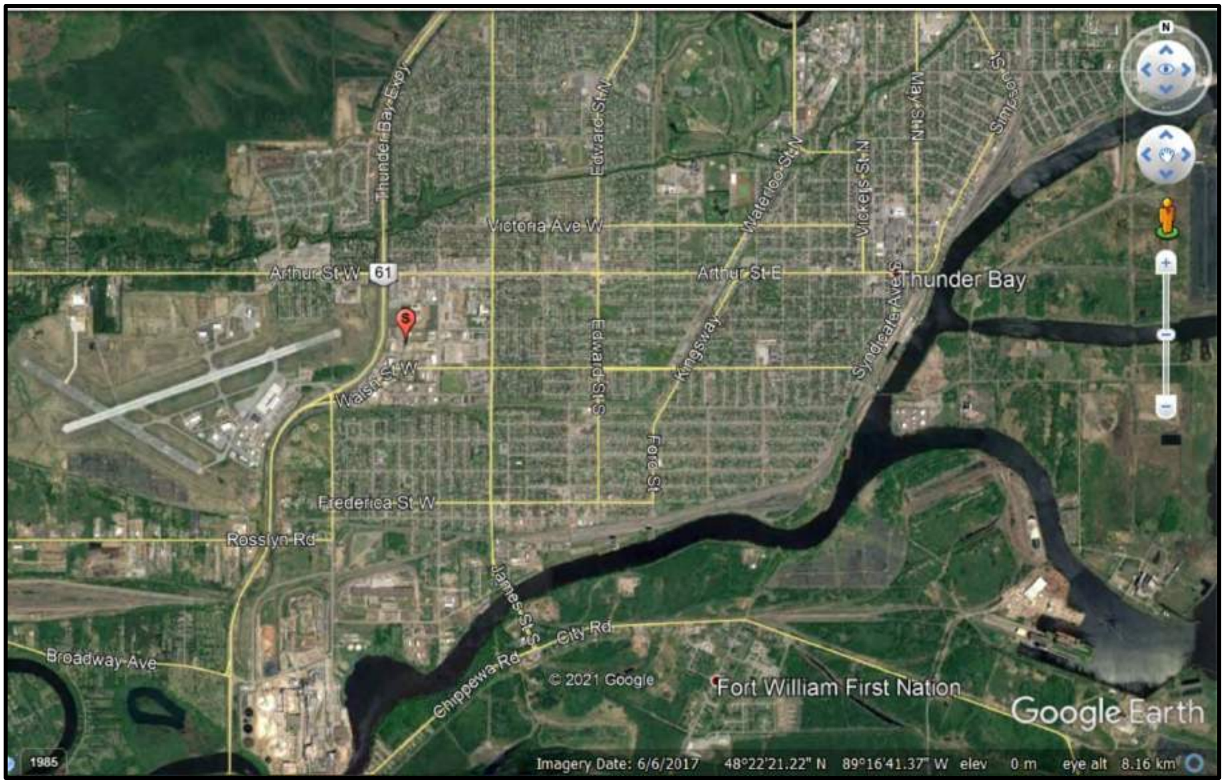


Figure 4 Source: Google Earth

Positioned on the western shore of Lake Superior, the City of Thunder Bay is the central urban focus for Northwestern Ontario. It is the predominant urban centre for supply and service to a region that extends west for 375 miles (600 kilometres) to the Province of Manitoba; east for 250 miles (400 kilometres) to the District of Algoma, Ontario; and north for varied and considerable distances by road or air to several small communities and a number of remote access First Nation Reserves.

The economy of Thunder Bay was founded around being the most western Canadian terminus of the Great Lakes and St. Lawrence Seaway system, as well as the harvest and process of natural resources (timber and minerals) from a vast and surrounding hinterland region. This economy has been in transition since the late 1970's, with reduced use of waterway transportation and significant but variable changes in the nature of mining and forestry.

Over the past 40 years, changes in mining and forestry have had a more noticeable impact on the surrounding region of Northwestern Ontario. However, they have also caused changes in the nature of employment and business in Thunder Bay. Since the 1970's, the Thunder Bay economy has undergone a slow and occasionally painful transition from transportation and resource harvest and production, to regional service and supply.

Changes in Thunder Bay Population

Referencing information published by Statistics Canada, population changes for Thunder Bay and its surrounding Census Metropolitan Area are tracked as follows.

The Thunder Bay CMA extends east from the City Limits to include the adjoining rural Municipality of Shuniah, and west to include the rural Municipality of Oliver-Paipoonge and the rural Townships of O'Connor, Marks and Conmee. It extends north and northwest to include the rural Townships of Gorham and Ware, Jacques, Fowler and Dawson Road Lots. It extends south and southwest to include the rural Township of Gillies and the Municipality of Neebing.

Table 2

	Thunder Bay City	Thunder Bay CMA
Census Year 2001	109,016	121,986
Census Year 2006	109,140	122,907
Census Year 2011	108,359	121,596
Census Year 2016	107,909	121,621

The population of both the City of Thunder Bay and the Thunder Bay CMA have remained stable from 2001 to the most recent Census in 2016, with no population growth observed.

EXHIBIT 31 – POPULATION PROJECTIONS

Scenario	2016 (Census)	2019 (forecast)	2051 (forecast)	Change (2019-2051)
Base Case	107,810	108,935	124,241	15,306
Low Case	107,810	108,122	113,863	5,741
High Case	107,810	109,751	135,535	25,784
High+ Case	107,810	109,751	155,802	46,051

Figure 5: Employment Land Strategy 2020

12.2 ICI Land Supply & Demand

The City of Thunder Bay undertook an Employment Land Strategy Study in 2020. This study was completed by Cushman & Wakefield. The following represent excerpts from the Cushman & Wakefield an Employment Land Strategy Study 2020 dated September 30, 2020.

Land Demand

> *The employment by industry projection can be translated into a forecast of land needs by identifying the type of buildings that are required for each category of employment. The following highlights the conclusions of our land demand analysis.*
>
> *Industrial – Using a benchmark industrial employment density and a typical industrial building site coverage ratio, there is demand for approximately 30 gross hectares of industrial land through the 2051 forecast horizon.*
>
> *Office – Guided by recent office development formats in the city, employment in sectors that are associated with office-type space demand is anticipated to generate demand for 7 gross hectares for office uses by 2051.*

Institutional – In discussion with the city's largest institutional employers, there is no identified near or medium-term requirement for additional Institutional-designated lands. Large institutional sites/campuses all offer excess lands that can accommodate future development, and on-site intensification is their principal focus of growth.

Retail-Commercial – The Consultant Team prepared two retail-commercial land demand scenarios that are guided by the same population forecast, but different assumptions about the amount of retail space demanded per capita. New retail-commercial uses will continue to emerge, and it is highly likely that some buildings within the existing inventory will become obsolete, and repurposed to a mixed-use or other form of redevelopment. It is recommended that the City plan for 25 gross hectares of retail-commercial land through 2051.

Our analysis has identified a considerable supply of vacant, designated employment lands in the City of Thunder Bay. The demand assessment indicates that future employment land requirements can be accommodated on existing sites. Therefore, there is no identified need to consider the conversion of any non-employment lands for employment purposes.

Land Supply

At an aggregate level, there is a vast supply of remaining undeveloped, designated industrial lands across Thunder Bay. This is particularly the case for Light Industrial-designated sites (520 vacant hectares) and Heavy Industrial-designated sites (over 200 vacant hectares), but the comment is also applicable to lands designated as Business Area (nearly 50 vacant hectares). Notably, this analysis does not even factor in existing occupied lands which may represent opportunities for intensification, or potentially redevelopment. A legacy of contamination of lands and buildings is a challenge in Thunder Bay on certain sites where there is a history of heavy industrial activity. Further, there are serviced employment lands at Thunder Bay International Airport that are suitable for industrial development – although these lands are not available for acquisition; these would be subject to a land lease arrangement.

While there are large concentrations of both Light Industrial and Heavy Industrial-designated vacant lands in areas on the city's periphery (including Mission and McKellar Islands), site visits by the Consultant Team have revealed a relative scarcity of vacant industrial lands in some of the more centrally-situated existing (built-up) employment areas. Of note, Innova Business Park represents a sizable inventory of remaining undeveloped lands that are centrally located, and more proximate to labour compared to other undeveloped planned industrial areas. Accordingly, the Light Industrial and Business Area lands located in Innova Business Park and to the north along Thunder Bay Expressway, Burwood Road, and Golf Links Road represent the best remaining undeveloped employment lands in the city, from a locational and market perspective.

Building Permit Activity

3.5 Non-Residential Building Permit Activity

The Consultant Team reviewed building permits provided by City staff for the period from January, 2010 – December, 2019. Over this past decade, some 2,000 non-residential permits were issued across the City of Thunder Bay. We have classified the permits into four categories: Commercial, Institutional, Industrial, and Other (the "Other" category captures properties such as utilities, performing arts centres, transportation terminals, and other mixed uses that do not fall into the prior three categories). The following are notable observations from our analysis:

- New building permits accounted for nearly one-half of the total permit value ($440 million), but represented just 12% of total permits, by count of permit.
- Permits for additions and alterations to properties – reflecting reinvestment in the stock of non-residential buildings – totaled $488 million, and an 88% share of total activity, by count of permits.
- By count of permit, the Commercial category accounted for just over one-half of total permits (52%), followed by Institutional (21%), and Industrial (13%). Buildings in the Other category represented a 14% share of the total activity.
- Commercial permits totaled $400 million in value, split evenly between new and addition/alteration work.
- Institutional permits totaled $337 million, with addition/alteration work representing a slight majority of the total permit value.
- Industrial permits totaled $57 million value, with two-thirds of the value being associated with new construction activity.

EXHIBIT 13 – VALUE AND NUMBER OF PERMITS BY BUILDING TYPE

Building Type	New		Addition/Alteration		Total	
	Value ($Millions)	#	Value ($Millions)	#	Value ($Millions)	#
Commercial	$201	89	$199	961	$400	1,050
Institutional	$149	15	$188	396	$337	411
Industrial	$38	116	$19	136	$57	252
Other	$52	14	$82	274	$134	288
TOTAL	**$440**	**234**	**$488**	**1,767**	**$928**	**2,001**

Source: City of Thunder Bay and Cushman & Wakefield

Figure 6: Employment Land Strategy 2020

12.3 Area Summary

There is a substantial supply of undeveloped industrial lands within Thunder Bay, however sites within areas that are serviced and within the core central employment areas are more limited. Absorption of Industrial land has been relatively slow with only 14 new facilities constructed between 2010 and 2019. Although absorption has been limited, it has been reported by several developers and real estate brokers that there appears to be some increased demand for industrial sites in the community.

12.4 Neighbourhood

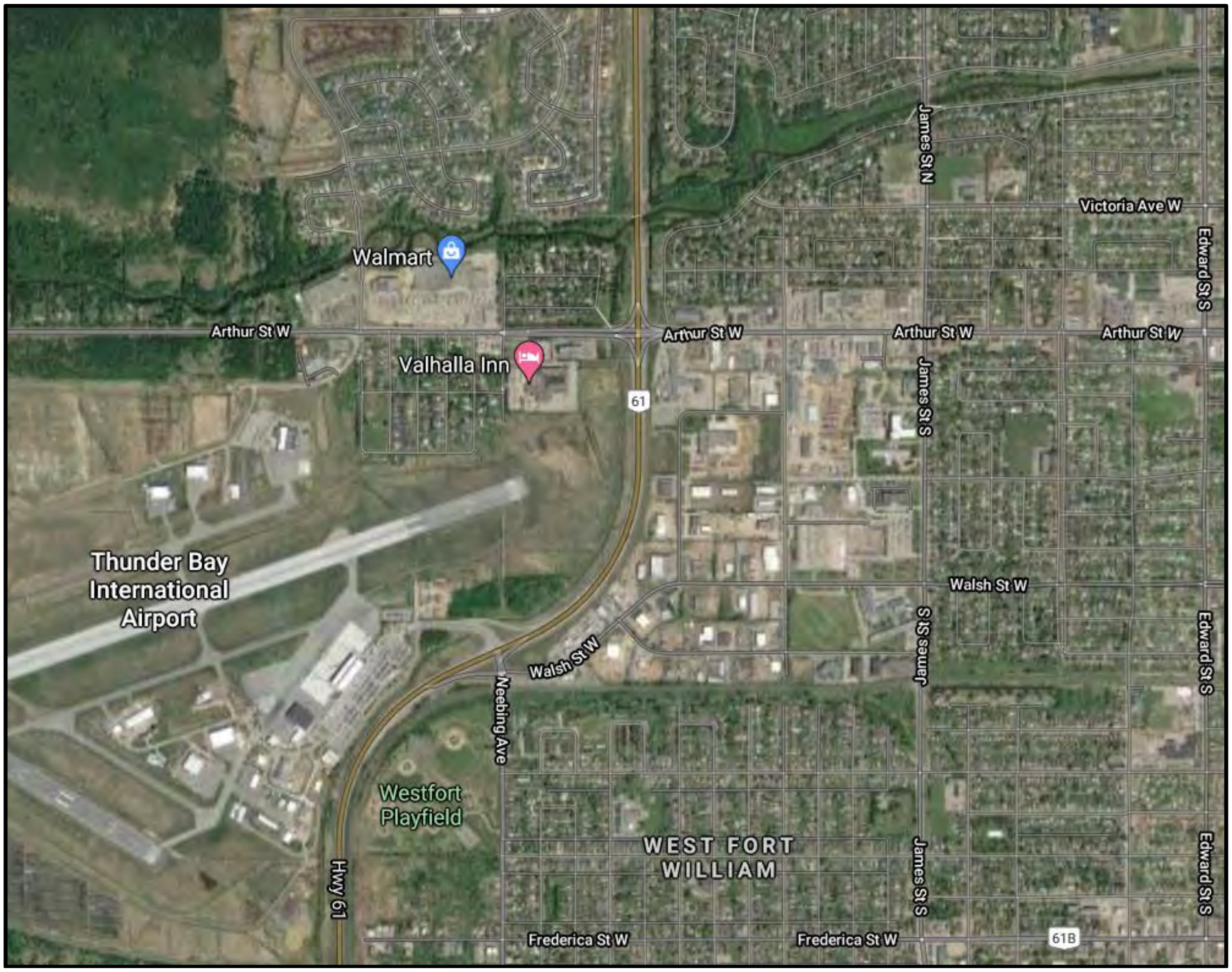


Figure 7 Source: City of Thunder Bay GIS

The subject property is in the southern portion of the City of Thunder Bay, within a concentration of industrial development known as the Beaverhall Industrial Area. This neighbourhood is generally bound by Highway 61 and Thunder Bay Airport to the west, Arthur Street to the north, James Street to the east and a rail line to the south. The neighbourhood is primarily comprised of general industrial uses with some service industrial / commercial uses. Arthur Street to the north is developed with commercial uses such as restaurants, gas stations and hotels. This location benefits from good access to Thunder Bay Airport and major transportation corridors.

Table 3

Neighbouring Uses	
North	To the immediate north is a large industrial property that has remained mostly vacant in recent history followed by a large equipment service shop.
South, West & East	Similar general industrial facilities.
Trends	
General Trend	Stable
Anticipated public / private improvements	The member is not aware of any anticipated public or private improvements that significantly impact the current short market value of the subject property.

13.0 Characteristics of the Market

13.1 National Economic Overview

The National Bank Monthly Economic Monitor (June 2021) provides the following:

- *The daily number of new cases of Covid-19 declared around the world has been declining markedly over the last month. In the developed economies, the drop can be attributed in large part to an acceleration of vaccine rollouts encouraging an outlook of fuller and more lasting reopening of economies. Elsewhere, improvement in public health is due rather to reinforcement of physical distancing rules, especially in India where in late April a flare-up of cases forced the reintroduction of strict lockdowns in some regions. Since access to vaccines is much more limited in emerging countries, herd immunity is unlikely before 2022. Developing countries will accordingly remain at greater risk of pandemic outbreaks in the coming months, a factor that could mean higher volatility of growth rates. We nevertheless continue to expect a solid rebound of the global economy in 2021 and are maintaining our forecast of 6.0% growth for the year. In fact, our confidence in a vigorous recovery has risen, since distribution of vaccines has greatly reduced economic uncertainty and downside risks for growth.*
- *The latest U.S. economic indicators confirm what has been our outlook for a few months now: a very strong revival stimulated by highly accommodative monetary and fiscal policies. Nonfarm payrolls grew 559,000 in May, less than the expected 675,000 but more than the months before, suggesting a slow but steady revival of the labour market in step with reopening of the economy. Also in May, headline 12-month CPA inflation was 5.0%, the highest in 13 years. For the CPI excluding food and energy the 12-month rise was 3.8%, the highest since June 1992. The three-month-annualized readings are still more impressive: headline inflation 8.4%, core inflation 8.3%. Up to now, the bulk of inflationary pressure has come in the goods-producing sector, but inflation could also take off in services if consumers decide, as we think they will, to spend more on activities unavailable in recent months (e.g. restaurant meals and travel). For the U.S. economy as a whole, we have left our forecast of 6.9% growth this year unchanged but have increased 2022 growth to 4.3% to reflect further government spending on infrastructure and social programs. In our projections, U.S. real GDP will be back to its potential by the third quarter of this year.*
- *Early in 2021, as the two largest provinces in Canada decreed shutdowns of non-essential businesses, public health conditions seemed to augur little good for the Canadian economy in Q1. And all the other G7 countries except the U.S. did have GDP declines during the quarter. In Canada, however, not only did the contraction that many had apprehended not materialize, but the quarter ended with very solid real growth of 5.6% annualized, a showing that put the Canadian economy in a leading position. In real terms its output came within 1.7% of its peak pre-pandemic quarter (Q4 2019) – second-best in the G7. In nominal terms the Q1 growth was even more spectacular taking nominal GDP to a best-in-G7 3.0% above its pre-recession peak. This month we are keeping our forecast of real growth in 2021 at 6.0%. after a pause in the recovery in Q2 due to public-health measures and to production backlogs in the auto industry due to microchip shortages, impressive growth can be expected to continue as vaccination picked up speed allowing the reopening of services that entail physical proximity. Our forecast for 2021 growth in nominal terms is now 12.6%, unseen in 40 years.*

Canada
Economic Forecast

*(Annual % change)**	*2018*	*2019*	*2020*	*2021*	*2022*	*2020*	*Q4/Q4 2021*	*2022*
Gross domestic product (2012 $)	2.4	1.9	(5.3)	6.0	4.0	(3.1)	5.2	2.9
Consumption	2.5	1.6	(6.0)	5.0	6.2	(4.4)	5.3	5.1
Residential construction	(1.7)	(0.2)	4.1	17.9	(5.1)	14.5	2.7	(4.3)
Business investment	3.1	1.1	(13.6)	0.1	5.7	(13.9)	4.8	4.8
Government expenditures	3.2	1.7	0.4	4.8	1.7	2.4	2.9	1.5
Exports	3.7	1.3	(10.0)	5.9	5.0	(7.4)	5.2	4.7
Imports	3.4	0.4	(11.2)	7.9	5.3	(5.9)	4.8	5.1
Change in inventories (millions $)	15,486	18,766	(15,937)	4,134	13,617	(287)	16,000	13,160
Domestic demand	2.5	1.4	(4.3)	5.6	3.7	(2.0)	4.3	3.1
Real disposable income	1.5	2.2	9.5	(0.0)	(0.6)	7.4	(0.5)	1.1
Employment	1.6	2.2	(5.1)	4.4	2.8	(2.9)	3.2	2.0
Unemployment rate	5.9	5.7	9.6	7.7	6.3	8.8	6.6	6.1
Inflation	2.3	1.9	0.7	2.7	2.5	0.8	3.1	2.3
Before-tax profits	3.8	0.6	(4.0)	33.4	2.2	9.4	16.8	4.0
Current account (bil. $)	(52.2)	(47.4)	(40.1)	5.0	(38.0)	....	....	....

** or as noted*

Financial Forecast**

	Current 6/11/21	*Q2 2021*	*Q3 2021*	*Q4 2021*	*Q1 2022*	*2020*	*2021*	*2022*
Overnight rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.75
3 month T-Bills	0.11	0.10	0.15	0.15	0.20	0.07	0.15	0.70
Treasury yield curve								
2-Year	0.32	0.30	0.35	0.45	0.65	0.20	0.45	1.20
5-Year	0.83	0.85	1.00	1.20	1.35	0.39	1.20	1.80
10-Year	1.37	1.40	1.55	1.75	1.90	0.68	1.75	2.20
30-Year	1.93	1.95	2.05	2.15	2.25	1.21	2.15	2.45
CAD per USD	1.21	1.19	1.17	1.20	1.21	1.27	1.20	1.23
Oil price (WTI), U.S.$	71	66	72	75	70	48	75	65

*** end of period*

Quarterly pattern

	Q1 2020 actual	*Q2 2020 actual*	*Q3 2020 actual*	*Q4 2020 forecast*	*Q1 2021 forecast*	*Q2 2021 forecast*	*Q3 2021 forecast*	*Q4 2021 forecast*
Real GDP growth (q/q % chg. saar)	(7.9)	(38.0)	41.7	9.3	5.6	1.2	7.4	6.6
CPI (y/y % chg.)	1.8	0.0	0.3	0.8	1.4	3.2	3.2	3.1
CPI ex. food and energy (y/y % chg.)	1.8	1.0	0.6	1.1	1.0	2.0	2.3	2.2
Unemployment rate (%)	6.4	13.1	10.1	8.8	8.4	8.2	7.4	6.6

National Bank Financial

Figure 8 Source: National Bank Monthly Economic Monitor June 2021

13.2 Real Estate Trends – MLS® Residential Average Price Trend (CREA):

There are no reliable statistics available for employment lands in the subject market place. To provide some context of the real estate market in Thunder Bay we reference the following statistics provided by CREA.

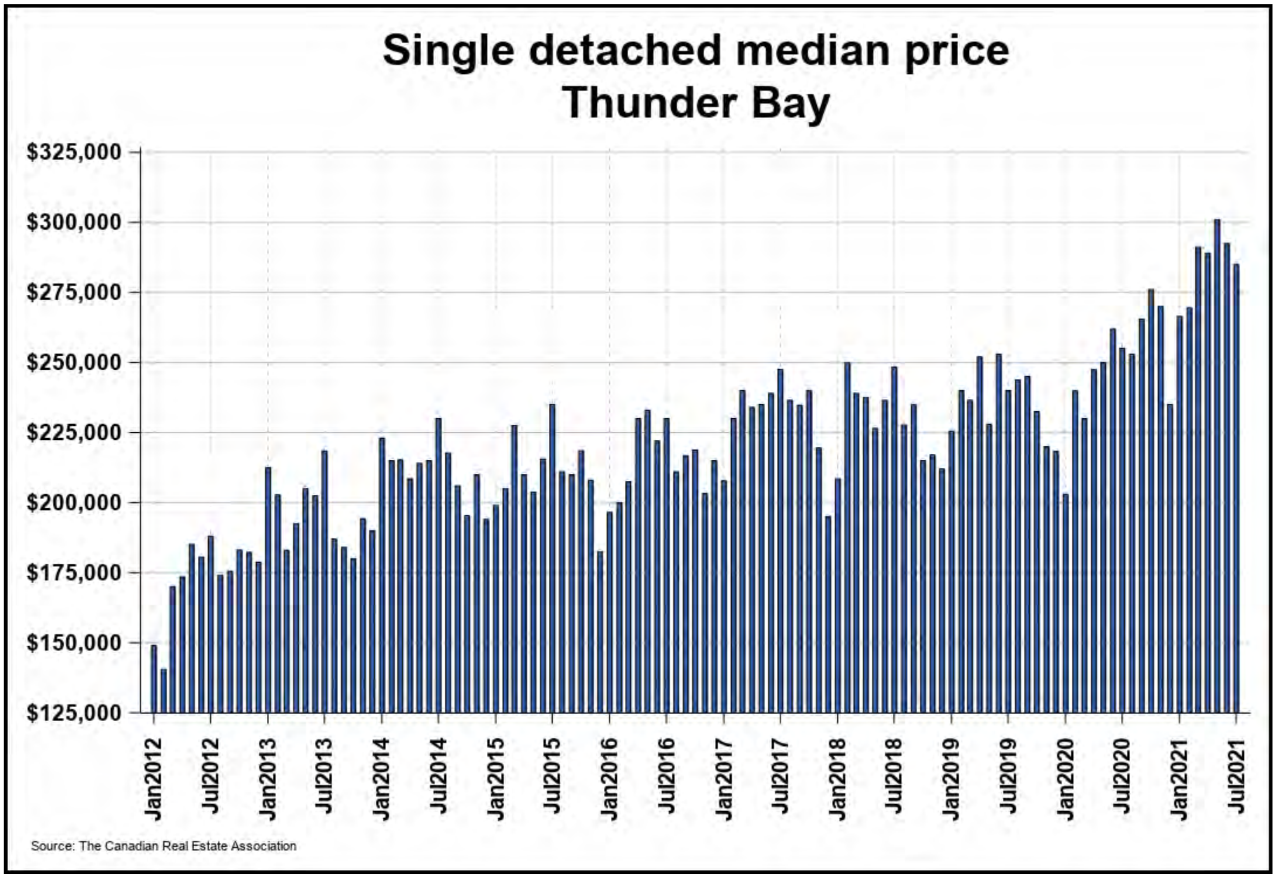


Figure 9: Source - CREA

On a year-to-date basis, single detached home sales totaled 651 units over the first seven months of the year. This was an increase of 79.8% from the same period in 2020.

The median sale price for single detached homes sold in July 2021 was $285,000, a gain of 11.7% from July 2020.

The more comprehensive year-to-date median price was $288,000, increasing by 16.9% from the first seven months of 2020.

Single detached properties spent less time on the market before selling in July 2021 than they had a year earlier. The median number of days on market for single detached home sales was 15 in July 2021, down from the 18 days recorded in July 2020.

The dollar value of all single detached home sales in July 2021 was $33.2 million, a sharp decrease of 10.5% from the same month in 2020.

14.0 Site Description

14.1 Site Details

Table 4

Item	Description
Area	2.82 acres (11,428 m2)
Frontage	270 feet +/-
Shape / Location	The subject is an interior site with a rectangular shape.
Topography	The site is generally level, cleared and fully graded.
Road Type	The site fronts Beaverhall Place, a paved two-lane collector road.
Entrances	Access to the property is provided by two entrances to Beaverhall Place.
Services / Utilities	Municipal Sewer and Well; Gas; Hydro
Site Improvements	The property is improved with a paved parking lot at the front of the building. This parking lot provides for 29 spaces including 1 barrier free. Access to the rear yard is provided through gated laneways on the north and south side of the building. The rear yard is fully fenced and graded with a gravel yard. The yard has some pole mounted lights and vehicle plug-in stations. A concrete pad is found along the southern property limit had is utilized for storage of transformers. The front yard is landscaped with maintained lawn and some trees. The property is also improved with two storage sheds including a 440 sq.ft. steel environmental storage building and a 400 sq.ft. steel storage building. Both buildings have roll up doors. Additional storage is provided by 12 seacans along the rear however these are considered equipment and not included in this valuation. This is also the case for an office trailer present on site.

14.2 Easement, Right of Way or Other Restrictions

There are no known easements, right of way or restriction which adversely impacts the value of the property.

14.3 Drainage and Soil Conditions

There are no known soil or drainage problems associated with the site, however, soil tests have not been made. We assume no responsibility for matters relating to the soil quality or any contaminants that may or may not be present.

Unless otherwise noted, at the time of our inspection we did not observe any obvious signs of contamination or environmental concerns. The member is not qualified to comment on environmental issues that may affect the market value of the property appraised, including but not limited to pollution or contamination of land, buildings, water, groundwater or air. Unless expressly stated, the property is assumed to be free and clear of pollutants and contaminants, including but not limited to moulds or mildews or the conditions that might give rise to either, and in compliance with all regulatory environmental requirements, government or otherwise, and free of any environmental condition, past, present or future, that might affect the market value of the property appraised. If the party relying on this report requires information about environmental issues then that party is cautioned to retain an expert qualified in such issues. We expressly deny any legal liability relating to the effect of environmental issues on the market value of the subject property.

14.4 Aerial Image

Figure 10

14.5 Yard Site Plan

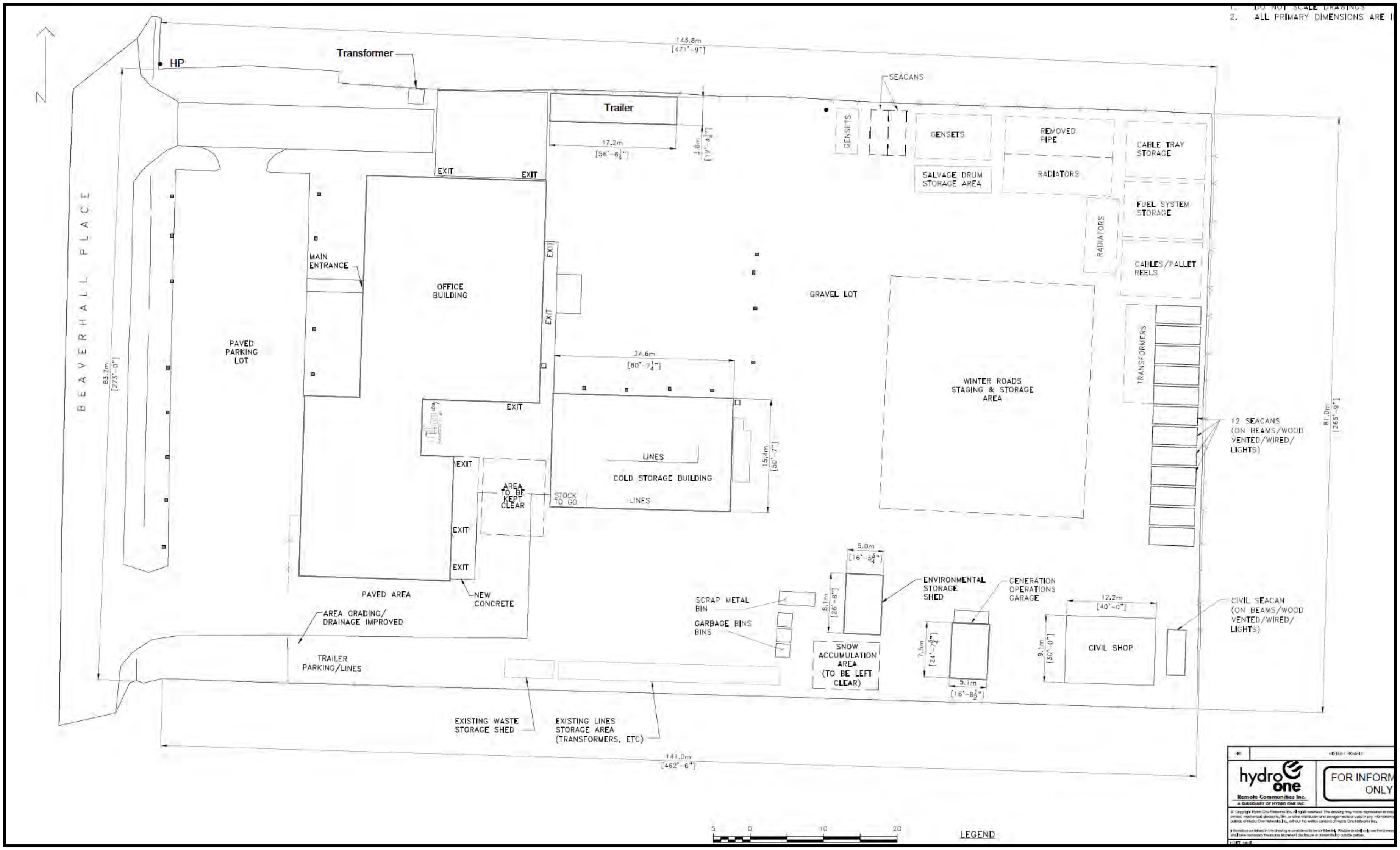


Figure 11 Source: Client

15.0 Building Summary

15.1 Primary Building Description

The subject primary building is currently developed as an office / service facility. We noted the following components in place at the time of inspection:

Table 5

Item	Description
Type or Design	Office / Service Building
Actual Age	Original Built 1978 +/- - Approximately 40 Years *It appears that the building was constructed in stages.
Effective Age	20 to 25 years +/-
Gross Floor Area (sq.ft.)	15,570 sq.ft.
Exterior Closure	Concrete Block, Brick & Steel
Main Floor Structure	Poured Concrete
Superstructure	Block & Steel Frame
Roof Structure	Steel Open Web Joist
Roof Covering	Membrane
Roof Age - Estimated	15 years +/-
Roof Condition	Most of the roof appears to be in average to good condition.
Windows	Double Glazed - Aluminium Frame
Plumbing	Copper and Plastic
Electrical Service	600-volt; 800-amp service
HVAC	Forced Air with A/C; Radiant Gas Heat; Ceiling Mount Forced Air Units; Automatic Ventilation in Service Shop
Sprinklers	No
Drive-in Doors	3 x 16' high; 1 x 10' high
Truck Level Doors	None
Clear Ceiling Height	Service Garage – 20' +/-; Storage Room – 12' +\-

Building Layout and Description

The main office / service industrial building is comprised of approximately 8,790 sq.ft. of office space and 6,780 sq.ft. of service shop, storage, and shop office area.

The office area is on two levels with approximately 6,390 sq.ft. on the main level and 2,400 sq.ft. on the upper level. The upper level was formerly storage mezzanine however it is now finished to an office standard and has been included in the building area. The main level is mostly comprised of open office area divided into workstations, a few private offices, conference room and a lunchroom. There are men's, women's and barrier free washrooms on the main level office. The main level office is finished with carpet, drywall and painted block and drop panel ceilings. The upper-level office is open office area with workstations and a large conference room. The ceiling clearance is roughly 7' to 8'. The space is carpeted with drywall walls and open painted ceilings. The office area is heated and cooled with roof mounted forced air units.

The rear service shop includes two service bays, storage and a shop office / change room area. The service bays include floor drains and are accessed by a 16' door. One bay has a 5-ton bridge crane. This space is heated with radiant gas units. The shop office area is utilized as computer stations. The building also includes a storage area at the south side of the building. This space is accessed by a 10' door and is heated with forced air units. Two shop offices are in this space.

Building Condition

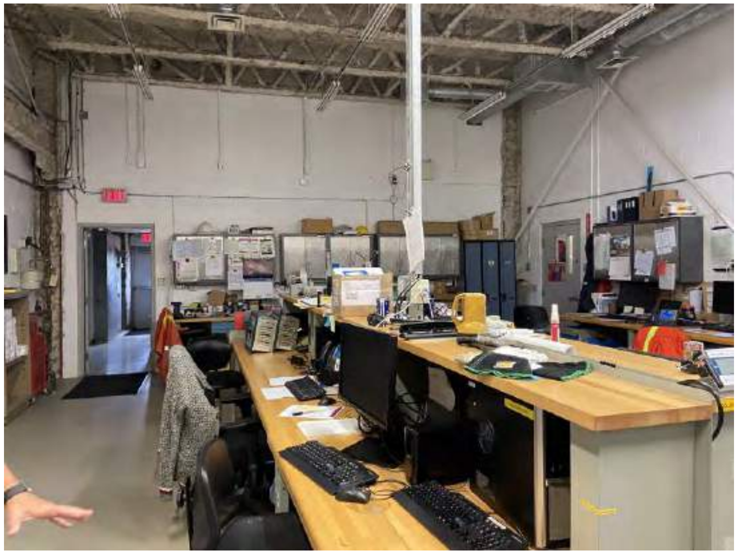
The building has been well maintained and there are no noted major repairs required at this time. The interior office finishes are in good condition. The shop space is clean and maintained. The exterior cladding demonstrates the age of the building but is in average condition.

Overall, the building is considered to be in average condition and well maintained. Some areas are considered to not fully reflect modern space such as the upper level office due to the low ceilings.

15.2 Interior Photographs

Change Rooms & Washrooms

Lunchroom



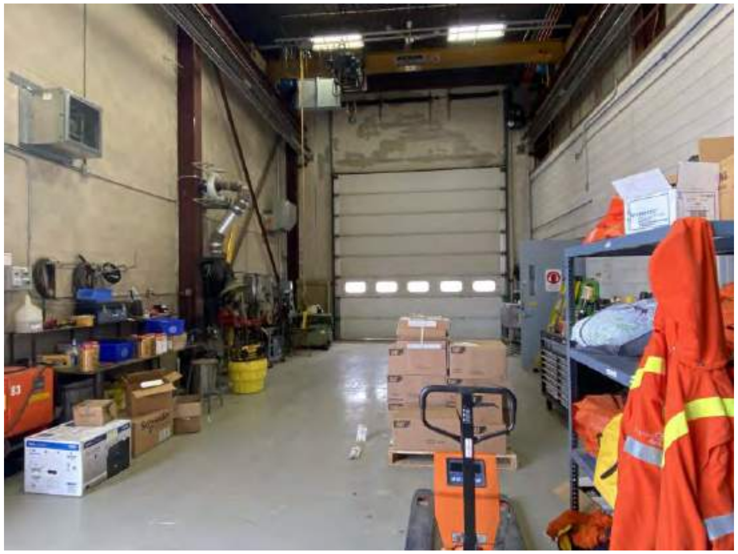
Industrial Workspace

Main Level Boardroom

Main Level Office

Mezzanine Office

Mezzanine Office Meeting Area



Service Shop Area

Storage Area

15.3 1st Floor Plan

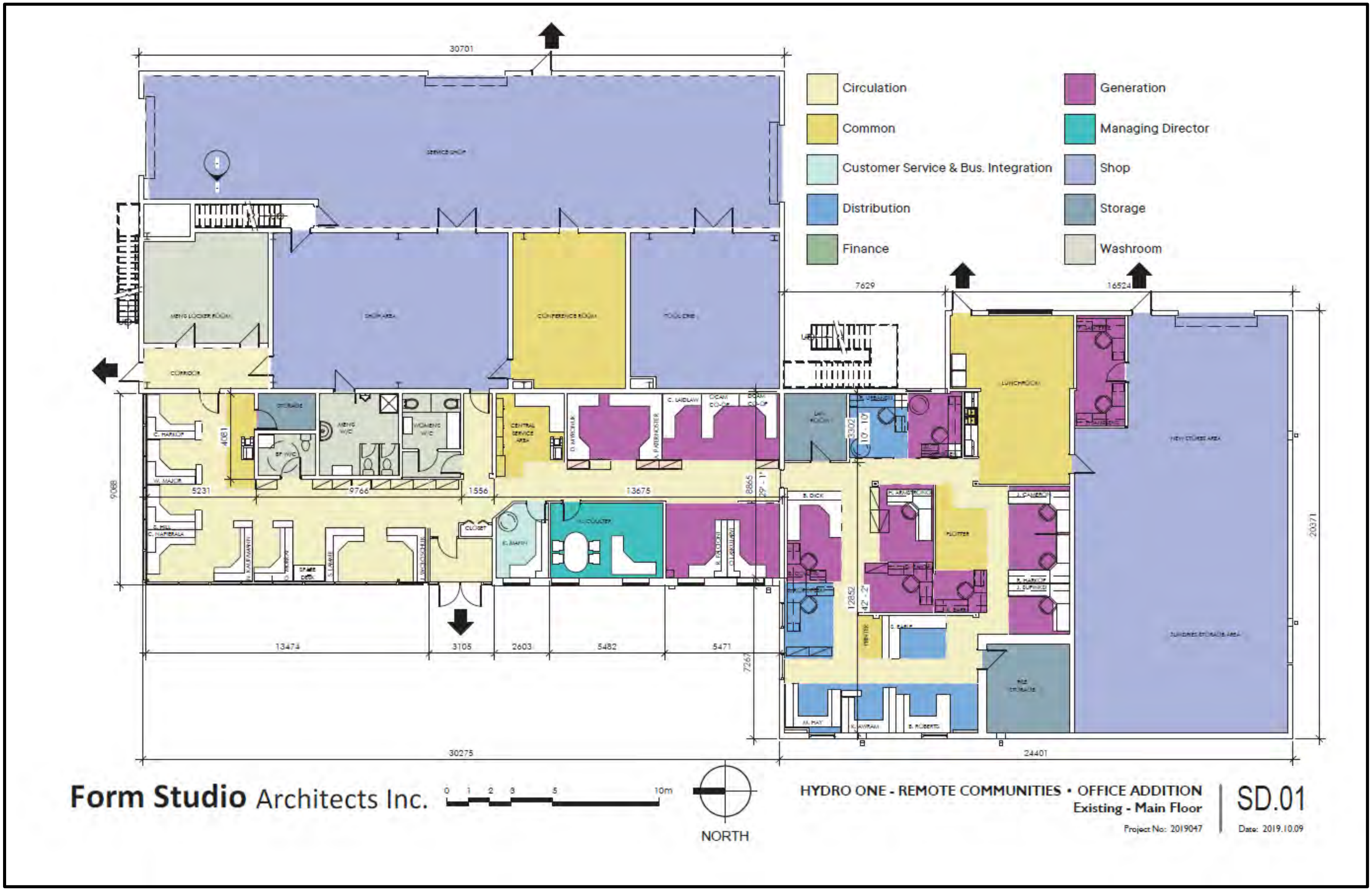


Figure 12

15.4 2nd Floor Plan

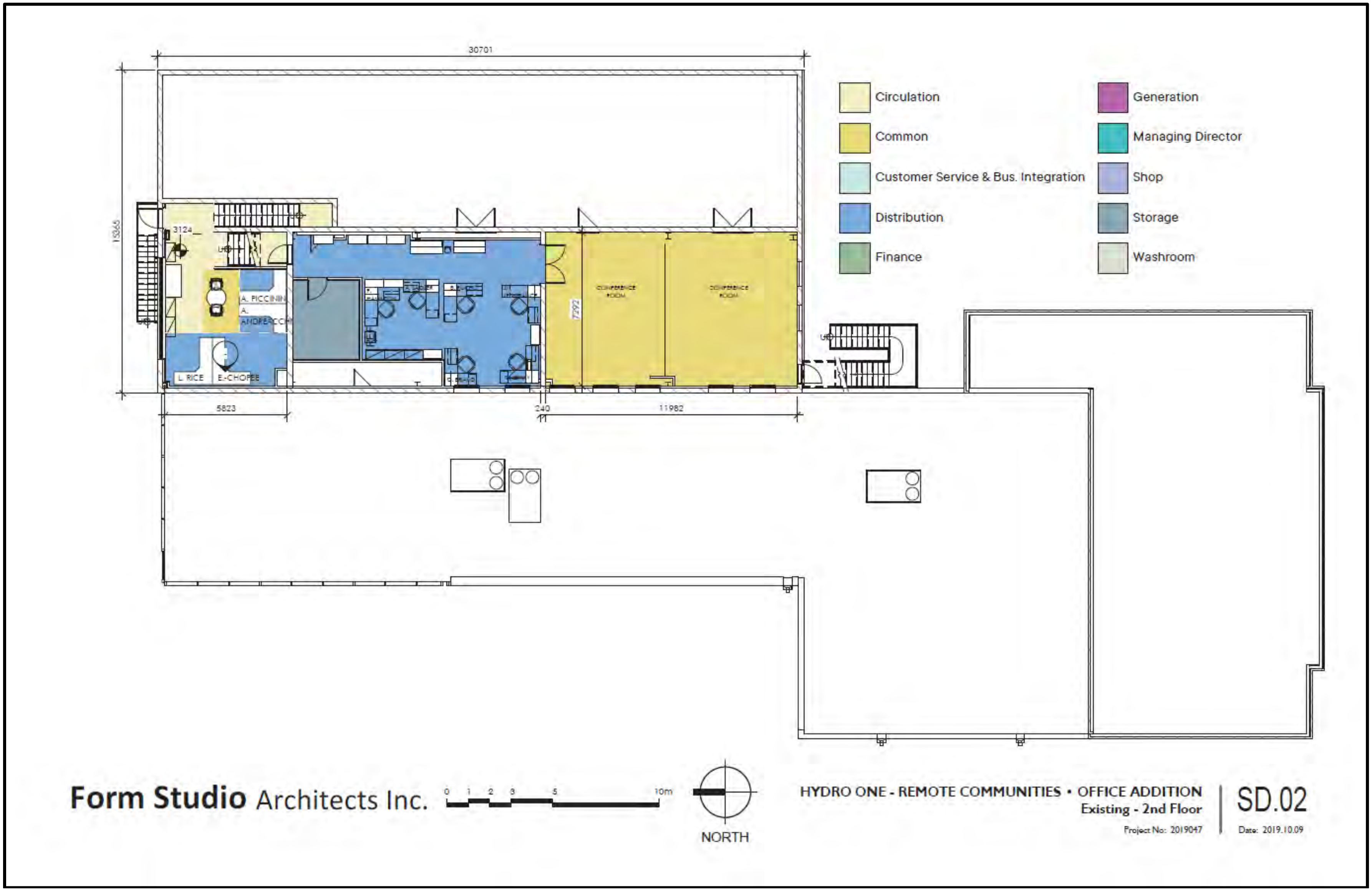


Figure 13

15.5 Warehouse Building

Table 6

Item	Description
Type or Design	Steel Storage Building
Actual Age	2000 +/-: Approximately 21 Years
Effective Age	20 years +/-
Gross Floor Area (sq.ft.)	4,065 sq.ft,
Exterior Closure	Steel Cladding
Main Floor Structure	Poured Concrete
Superstructure	Steel Frame
Roof Structure	Steel Frame
Roof Covering	Steel
Roof Age - Estimated	Original
Roof Condition	Reported to be in Good Condition
Windows	None – One wall has some translucent panels.
Plumbing	None
Electrical Service	Provided from Main Building
HVAC	None
Sprinklers	No
Drive-in Doors	2 x 16' height
Truck Level Doors	None
Clear Ceiling Height	18' +\-

Building Layout; Description and Condition

This is an unheated storage building with steel construction providing for roughly 18' clearance and fluorescent / LED lighting. Access to the building is provided by two 16' drive-in doors. The building appears to be well maintained and in average condition.

15.6 Workshop

Table 7

Item	Description
Type or Design	Wood Frame Workshop
Actual Age	2014 +/-: Approximately 7 Years
Effective Age	7 years +/-
Gross Floor Area (sq.ft.)	1,200 sq.ft.
Exterior Closure	Vinyl Cladding
Main Floor Structure	Poured Concrete
Superstructure	Wood Frame
Roof Structure	Wood Truss
Roof Covering	Steel
Roof Age - Estimated	Original
Roof Condition	Good Condition
Windows	Vinyl
Plumbing	None
Electrical Service	Provided from Main Building
HVAC	Roof Mounted Electrical Heaters; Heat Recovery Ventilation Unit; Vent Fans
Sprinklers	No
Drive-in Doors	1 x 10' height
Truck Level Doors	None
Clear Ceiling Height	12' +\-

Building Layout; Description and Condition

This is a heated workshop that is insulated and finished with drywall walls and ceilings. The building has a 1-' drive-in door and a single man door. The building is in good condition and is maintained.

15.7 Interior Photographs

Warehouse Interior

Workshop Interior

Warehouse Interior

Workshop Interior

16.0 Highest and Best Use Estimate

Highest and Best Use is defined as:

"the reasonably probable and legal use of vacant land or an improved property, that is physically possible, appropriately supported, financially feasible, and that results in the highest value."[2]

The four criteria that Highest and Best Use must meet are; legal permissibility, physical possibility, financial feasibility, and maximum profitability.

- ***Legal Permissibility***

  The Highest and Best Use of a vacant site is often dictated by the governing zoning bylaws and official plan policies. The Highest and Best Use must be legal and within the realm of probability.

- ***Physical Possibility***

  Soils, topography, drainage, parking, site planning, setbacks, etc., must be suitable for the envisioned use.

- ***Financially Feasible***

  There must be market demand for the property in its current use. If an alternate use is contemplated, there must be market support that the continued use is no longer financially feasible.

- ***Maximum Profitability***

  There must be a demand for such a use and that use must be "profitable" and such that it will deliver the highest net return for the longest period of time.

The concept of value is founded on one cardinal principle: **Utility**. For an object to have value, it must possess or be capable of providing some form of beneficial utility or enjoyment to the owner, to the user or even the casual observer of the product.

The Highest and Best Use of a vacant site is often dictated by the governing Zoning By-laws. The Highest and Best Use must be legal and within the realm of probability. There must be a demand for such a use and that use must be "profitable" and such that it will deliver the highest net return for the longest period of time.

[2] *"The Appraisal of Real Estate, Second Canadian Edition", copyright 2005 Appraisal Institute, page 12.1*

16.1 Land as if Vacant

The subject site is a 2.82-acre parcel designated Light Industrial in the Official Plan and zoned Medium Industrial. The site is cleared and graded and well suited to an industrial / employment-based use. The land use allows for a range of industrial uses including open storage. Demand for lands within the subject neighbourhood appears to be present with several parcels trading in the past couple of years.

Use of the site for an industrial use as zoned and designated is legally permissible, physically possible, financially feasible and provides the maximum profitability to the lands.

We are unaware of any use that would provide a higher return to the subject property than as zoned. Therefore, the Highest and Best Use of the subject property as if vacant is concluded to be ***development as a permitted industrial use.***

16.2 Property as Improved

The subject property "as improved" represents an industrial facility having a primary building offering a large amount of office space and service garage space, an unheated warehouse and a small workshop. The property has a large graded and fenced storage yard that includes a number of sheds and storage containers.

The subject property provides well for an industrial user requiring significant office space and a large yard storage area / equipment parking. The buildings are well maintained and offer good utility. If available on the open market it is likely that demand would be present.

The use of the improved property is legally permissible, physically possible, financially feasible and provides the maximum profitability to the lands.

We are unaware of any other use that would provide a higher return to the subject property than as currently developed as an Industrial facility. Therefore, the Highest and Best Use of the subject property as improved is concluded to be ***continued industrial use as developed.***

17.0 Appraisal Procedures

17.1 Improved Value

There are three traditional approaches to value namely: (1) The Cost Approach, (2) The Income Approach, and (3) The Direct Comparison Approach.

- ***Cost Approach***

This method uses the value produced by estimating the "Market Value" of the land as though unimproved and adding to that the cost of replacing the improvement less any accrued depreciation.

- ***Income Approach***

The Income Approach to value is the method under which the annual net income produced by a property is capitalized at an appropriate rate into an indication of value.

- ***Direct Comparison Approach***

This is the method that compares the subject to sales and listings of similar properties. The comparables are adjusted for size, quality, location, etc. to produce an indication of value of the subject.

18.0 Valuation

Given the current market conditions, location and type of property the most relevant approaches to value in this analysis are determined to be as follows:

- Cost Approach
- Direct Comparison Approach

In this instance the Income Approach has not bee utilized. Although sometimes suitable it appears that larger standalone industrial facilities such as the subject in the local market are in most instances owner occupied and are not typically acquired as income producing properties. As such we have not applied an Income Approach in this instance.

19.0 Cost Approach

19.1 Land Valuation

In this instance we have selected the Direct Comparison Approach as the best method of valuation for the subject as if vacant. The following table summarizes the sales considered in our review. Detailed sale descriptions are in the addenda of the report.

Table 8

#	Location – Thunder Bay	Lot Size (acres)	Zoning	Sale Price	Sale Date / Registration Date	Time Adjusted Rate per Acre (rounded)	Adjustments Applied			Adjusted Value Per acre
Neighbourhood Sales							**Location**	**Site Size / Scale**	**Topography**	
1	645 Beaverhall Place	1.81	Light Industrial	$325,000	11/26/20	$187,000				**$187,000**
2	600 Beaverhall Place	1.56	Medium Industrial	$250,000	12/04/20	$166,000				**$166,000**
3	685 Beaverhall Place	0.86	Light Industrial	$300,000	6/25/21	$350,000		↓		**$262,500**
4	625 Mountdale Ave	1.45	Medium Industrial	$167,000	5/04/16	$133,000				**$133,000**
5	625 Beaverhall Place	1.69	Highway Commercial	$300,000	9/09/14	$210,000				**$210,000**
Other Sales										
6	295 Court St S	3.48	Medium Industrial	$1,150,000	7/30/21	$330,000	↓			**$231,000**
7	Dunlop St	1.09	Medium Industrial	$151,000	3/18/21	$141,000			↑	**$183,300**
8	224 Burwood Road	2.83	Prestige Industrial Hold	$399,900	1/15/20	$154,000	↑		↑	**$215,600**

↑ - Inferior to the Subject; ↓ - Superior to the Subject

19.2 Land Value Analysis

The preceding Table outlines 8 sales of employment lands located in the City of Thunder Bay. The sales include 7 sites zoned for light or medium industrial uses and one neighbourhood sale zoned highway commercial. Five of the sales are from within the subject immediate neighbourhood while 3 are within other industrial locations throughout Thunder Bay.

Majority of the sales are relatively recent being from 2020 or 2021. Two of the sales are dated but have been included due to the location within the immediate neighbourhood. Industrial / employment land values appear to have experienced some upward pressure over the past year or so while values had been more stagnant prior to this. We have applied a time adjustment of 1.5% per annum to the end of 2019 and a 6% per annum adjustment for 2020 and 2021. Once adjusted the sale provide a time adjusted sale price range of $133,000 to $350,000 per acre.

The wide time adjusted price range is primarily a result of differences in location, topography and site size / scale. Adjustments have been applied to account for these items.

Index 1 to Index 5 are all located in the immediate area. All the sites are cleared and generally flat. Some zoning differences are present but all sites appear to provide for a range of employment uses. Index 5 is zoned for commercial, however, this is related to the former hotel use and it is likely that an alternate light industrial use would be suitable. One sale is much smaller at 0.86 acres and required and adjustment for scale. Once adjusted these sales indicate a range of $133,000 to $262,500 per acre. The lower end of the range represents a dated sale of a nearby site. Although adjusted for time the adjustment may not adequately account for changes over this extended period. The more recent sales (Index 1, 2 & 3) provide a narrower range of $166,000 per acre to $262,500 per acre.

Index 6 is the pending sale of a large parcel of employment land located on the fringe of the downtown core. This site has good exposure to a four-lane road and appears to possibly have some alternate development potential. Following an adjustment for superior exposure this sale indicates a rate of $231,000 per acre.

Index 7 is a small industrial parcel located centrally within Thunder Bay. The site is forested and required greater site works. Once adjusted this sale indicates a rate of $183,300 per acre.

Index 8 is the sale of a parcel of prestige industrial land located to the north of the subject. This site required clearing and greater site works. Once adjusted the sale indicates a rate of $215,600 per acre.

The selected comparable sales provide an adjusted range of $133,000 to $262,500 per acre. As noted, the more recent neighbourhood sales provide a range of $166,000 to $262,500 per acre. The upper end of this range reflects the sale of a small site that was purchased by a nearby industrial tenant. It is our understanding that the purchaser was somewhat motivated and we would expect a rate for the subject below this indication. The additional sales from outside the neighbourhood appear to support the indications provided by the neighbourhood sales.

Considering the available sales data, it appears that industrial lands similar to the subject are in trading in the general range of $180,000 to $240,000 per acre with upward pressure experienced in the past year. This appears to be stronger than observed in past years but is supported by the available market data. Considering the strengthening in the market, a value closer to the upper end of the range is appropriate. Therefore, we conclude a subject site value of **$220,000 per acre** equating to a site value of **$620,400**.

19.3 Improvement Value

We have utilized the "SwiftEstimator" (Marshall and Swift Cost Service) online building cost estimator. Depreciation has been applied based on an overall observed rate. The following table summarizes our estimate:

Table 9

Cost Approach Summary Table			
Item	**Area**	**Rate**	**Total**
Building Cost			
Main Office / Service Shop Building (Inc. Crane)	15,570	$171	$2,662,470
Warehouse	4,065	$97	$394,305
Workshop	1,200	$108	$129,600
Total Building Cost:			**$3,186,375**
Less: Depreciation	Main Building	55%	-$1,464,359
	Warehouse	40%	-$157,722
	Workshop	20%	-$25,920
Total Depreciation			-$1,648,001
Total Depreciated Building Cost:			**$1,538,375**
Plus: Site Improvements Depreciated:			$350,000
Plus: Land Value as if Vacant	2.82	$220,000	$620,400
Estimated Value Cost Approach (Rounded)			**$2,509,000**

20.0 Direct Comparison Approach

The Direct Comparison Approach provides a basis for value through a process of adjustments for differences between comparable sales and the subject property. In this method, similar properties recently sold or offered for sale are analysed and comparisons are made based on a number of elements of comparison. These elements include real property rights conveyed, financial terms, condition of sale, expenditures made immediately after purchase, market conditions, location, physical characteristics, economic characteristics, use and zoning, and non-realty components of value. Elements that apply can be addressed quantitatively or qualitatively.

A unit of measurement is defined as a feature of a property that can be measured, for purposes of comparison, with the same common element or component of another property. For example, a selling price per “unit” could express a figure on a per square foot basis, per acre basis, per suite basis, or per room basis.

In this approach, similar properties recently sold or offered for sale are analysed and comparisons are made based on a number of elements of comparison. Elements of Comparison include:

- ***Real Property Rights Conveyed***
  Adjustments are made under this category for items such as existence of right of ways, easements, restrictive covenants which may impact the property.

- ***Financial Terms (financing)***
  Differences in financing arrangements that result in a higher or lower transaction price.

- ***Condition of Sale***
  Motivation of the buyer or seller that differs from the usual market conditions resulting in a sale that would not represent the market value of a property. This adjustment could be in the form of the vendor needing to make a quick sale due to a cash flow problem, a neighbouring property owner motivated to expand, or might emerge for a key property in an assembly.

- ***Expenditures Made Immediately After Purchase***
  Any expenses which a knowledgeable buyer would have considered and affected the price paid.

- ***Non-Realty Components***
  Any non-realty items such as personal property and business operations included in the sale price of the comparable.

These preceding adjustments are made before adjustment for market conditions (time).

- ***Market Conditions***
  Adjustments made for changes over time due to inflation, deflation or changes in investors’ perceptions of the market. In the cases where a listing is considered it may be that a downward adjustment should be applied as typically properties sell for less than the asking price.

Following market adjustments, adjustments are made under the following main headings on a percentage or dollar basis as deemed appropriate.

- ***Location***
- ***Physical Characteristics***
  Physical differences such as site and building size, condition, accessory buildings etc.
- ***Economic Characteristics***
  Adjustments for attributes that directly affect its income. This element is usually applied to income-producing properties.
- ***Use and Zoning***
  Difference in current use potential of a comparable and the subject property.

Qualitative vs. Quantitative

Adjustments can be in the form of quantitative and/or qualitative adjustments. Quantitative adjustments may be applied as a percentage or dollar amount. Qualitative adjustments do not apply specific adjustments to sales but rather relies on comparisons. Qualitative techniques include trend analysis, relative comparison analysis and ranking analysis. In this instance we have completed a Quantitative analysis.

A survey of the local market area has been conducted and the following sales are concluded to best support value for the subject property. Detailed sales descriptions and sales location maps can be found in the Addenda of this report.

20.1 Direct Comparison Approach Table

Table 10

#	Location (Thunder Bay)	Type	Gross Floor Area (sq.ft..)	Lot Size (acres)	Coverage Ratio	Office Area	% Office	Ind Clear Height (feet)	Sale Price	Sale Price per Sq.Ft. of Building	Date for Time Adjustment	Time Adjusted Value	Time Adjusted Rate per Sq.Ft.	Adjustments Applied					Adjusted Value per sq.ft. (rounded)
S			**20,835**	**2.82**	**17%**	**8,790**	**42%**	**18-20**						**Location**	**Bldg. Size/ Scale**	**Bldg. Cond./ Quality**	**Office**	**Site size/ Coverage**	
1	1400 Walsh Street West	Industrial	10,001	3.50	7%	5,610	56%	20	$1,300,000	$130	April 30, 2020	$1,398,000	**$140**		↓	↓	↓	↓	**$101**
2	1210 Commerce Street	Industrial	6,170	2.29	6%	1,800	29%	21	$1,100,000	$178	December 18, 2020	$1,141,000	**$185**		↓	↑	↑		**$142**
3	1230 Carrick Street	Industrial	21,065	3.73	13%	5,600	27%	14-21	$1,950,000	$93	August 14, 2020	$2,063,000	**$98**	↑		↑	↑	↓	**$107**
4	605 Hewitson Street	Industrial	19,314	2.35	19%	10,080	52%	14 to 20	$2,750,000	$142	November 13, 2020	$2,868,000	**$148**	↓		↓	↓		**$124**
5	879 Tungsten Street	Industrial	16,660	1.68	23%	1,600	10%	16 to 20	$1,400,000	$84	November 1, 2018	$1,561,000	**$94**				↑	↑	**$111**
6	544 Winnipeg Avenue	Office	10,003	0.66	35%	10,003	100%	n/a	$1,200,000	$120	December 17, 2018	$1,336,000	**$134**						**$134**
7	1204 Roland Street	Office	10,128	0.98	24%	10,128	100%	n/a	$1,025,000	$101	February 19, 2019	$1,138,000	**$112**						**$112**

↑ - Inferior to Subject Property; ↓ - Superior to Subject Property; ↔ - Relatively Similar to subject property

20.2 Analysis

We have completed a thorough search for sales of similar industrial facilities throughout Thunder Bay. The subject facility is somewhat unique given its large portion of office space relative to industrial space. Sales of large industrial facilities are not common in the local market with most sales being buildings under 10,000 sq.ft.. The preceding sales Table identifies 7 sales considered useful for identifying the value potential of the subject facility. Index 1 to 5 represent industrial facilities with a mix of industrial and office space. Index 6 and 7 represent sales of office buildings to provide context relative to industrial properties. We have applied a time adjustment of 1.5% per annum to the end of 2019 and a 6% per annum adjustment for 2020 and 2021. Once adjusted the sale provide a time adjusted sale price range of $1,138,000 to $2,865,000 or $94 to $185 per sq.ft..

We have analysed the sales on a per sq.ft. basis as it is considered best reflected of the market place for this property type. The wide range in the time adjusted sales price is a result of variation in location, site size, building size, office space and building condition / quality. To better reflect the subject property, we have applied adjustments for these items where deemed appropriate. The adjustment applied for building condition / quality accounts for a range of attributes such building type, construction quality, condition, ceiling clearance, interior finish, etc..

Index 1, time adjusted to $140 per sq.ft. is the sale of a service garage situated on a large site within the subject neighbourhood. This building was formerly a Cummins sales and repair shop and was purchased for a similar use. The building is reported to have a large portion of office / showroom with 4 service bays. The purchaser appears to be an industrial user with some vehicle service needs. The site is larger while the building is overall superior but much smaller. Once adjusted this sale indicates a value of **$101 per sq.ft.**.

Index 2, time adjusted to $185 per sq.ft. is a much smaller industrial facility situated on a similar sized site. The building is a steel industrial building in modest condition. The time adjusted rate per sq.ft. is influenced by the small building size relative to the large site and as such a large downward adjustment is needed for building size / scale. This sale has been included as it is a neighbourhood sale with a similar site size/coverage. Following necessary adjustments this sale indicates a value of **$142 per sq.ft**.. Due to the much smaller building size this sale appears to be an outlier.

Index 3, time adjusted to $98 per sq.ft. is the sale of a similar sized industrial facility reported to have a large portion of office space. This building appears to be in average condition while the site provides for a large fenced yard. An upward adjustment is needed for overall building condition / quality while a downward adjustment is needed for the larger site/coverage. The location is a desirable central area but is somewhat removed at the end of Carrick Street, abutting the Needing/McIntyre floodway. Once adjusted this sale indicates a rate of **$107 per sq.ft.**.

Index 4, time adjusted to $148 per sq.ft. is the sale of two adjoining properties improved with 3 buildings. The buildings include a light industrial building with a large office section, a service shop and an office / service commercial building. The buildings ranged in condition and quality from average to good. Overall on a whole on whole comparison, this sale is considered superior to the subject property. The location has greater corner exposure and the overall building quality is superior. Once adjusted this sale indicates a rate of **$124 per sq.ft.**.

Index 5, time adjusted to $94 per sq.ft. is a large industrial facility located centrally within Thunder Bay. The building was constructed in stages over a period of roughly 20 to 30 years with the most recent addition in the 2000's. The building is reported to have been in average to good condition and included a small fenced yard. Once adjusted this sale indicates a rate of **$111 per sq.ft.**.

Index 6, time adjusted to $134 per sq.ft. and **Index 7,** time adjusted to $112 per sq.ft. represent sales of office buildings within Thunder Bay. These buildings represent entry to mid level office within industrial neighbourhoods that would be similar to the subject office space. These sales have been included to provide context and a comparison to the subject's large portion of office space. The time adjusted sale price rates of the office buildings suggest that this type of office is trading at similar values to light / service industrial buildings with only a small premium attributable to the office. We have not applied any further adjustments.

20.3 Direct Comparison Approach Conclusion

The selected comparable sales provide an adjusted range of $101 to $142 per sq.ft.. As noted, Index 2 appears to be somewhat of an outlier and is above most other available references. Excluding this sale and the office sales (Index 7 and 8) which were included to provide context, the remaining sales provide a narrowed range of $101 to $124 per sq.ft. with an average of $111 per sq.ft.. This narrowed range is considered to be a good indication of the value potential for the subject property and a conclusion within the range is considered appropriate.

Therefore, based on the available market data and the preceding analysis, we conclude a subject value of **$105 to $115 per sq.ft.** equating to a value of **$2,188,000 to $2,396,000** based on a total building size of 20,835 sq.ft..

21.0 Reconciliation and Final Estimate of Value

The following estimates have been provided in this analysis:

Cost Approach to Value	***$2,509,000***
Direct Comparison Approach	***$2,188,000 to $2,396,000***

The Cost Approach typically sets the upper limit to value and as a building ages this approach can have less reliability given the depreciation estimates applied. In this case the Cost Approach is felt to provide an upper limit to the subject property and is above the value indicated by the Direct Comparison Approach.

The Direct Comparison Approach is generally considered the most effective method of valuing a property. This is due to its close representation of market conditions for similar type properties. The Direct Comparison Approach analysis usually holds significant weight as to the value of the subject property type and in this instance offers a good indication of value.

Based on the value estimates provided, the "market value" of the property is considered to be in the range of $2,200,000 to $2,400,000 and the conclusion is the best estimate that can be reached within the range.

Based on the analysis of the available data, it is our opinion the "Market Value" of the herein described property is $2,300,000.

TWO MILLION THREE HUNDRED THOUSAND DOLLARS

Any Extraordinary Assumptions, Hypothetical Conditions and/or Extraordinary Limiting Conditions are noted in Section 6.0.

- Exposure Time

Exposure Time may be defined as: "The estimated length of time the property interest being appraised would have been offered on the market prior to the hypothetical consummation of a sale at market value on the effective date of the appraisal; a retrospective estimate based upon an analysis of past events assuming a competitive and open market." Exposure time is a function of price, time and use, not an isolated opinion of time alone. This is a retrospective estimate based upon an analysis of past events assuming a competitive and open market. It is always presumed to have preceded the effective date of the appraisal.

If competitively marketed, it is estimated that an exposure time of **6-12 months** prior to the effective date of valuation would have been required to sell the subject property at the appraised market value.

22.0 Summary of Qualifications

Peter Spivey, B.Sc., AACI, P.App

Peter Spivey obtained his honours degree in biology with a minor in geography from the University of Guelph. Upon completion of his university degree, Peter Spivey entered the appraisal field and achieved his AACI (Accredited Appraiser Canadian Institute) designation in 2009.

RELATED WORK HISTORY

2006 – Present	Andrew, Thompson and Associates Ltd.

QUALIFICATIONS

AACI	Accredited Appraiser Canadian Institute This designates a fully accredited membership in the Institute and indicates a high level of competence in a wide range of real estate appraisal.
B.Sc.	Bachelor of Science • Honours Marine and Freshwater Biology Major (University of Guelph) • Geography Minor (University of Guelph)

CERTIFICATES AND COURSES

UBC - Real Estate Appraisal Course Stream (15 Courses)

Completion of the Eco Gift Seminar

OTHER ACHIEVEMENTS

Director, Ontario Expropriation Association.

VALUATION EXPERIENCE

Land	Residential Subdivision; Industrial Subdivisions; Rights of Way; Easements; Highway Widenings; Institutional Sites; Waterfront; Recreation Lands; Agricultural, Wood Lot, Escarpment Lands, etc.
Commercial	Downtown; Strip Plaza; Special Use; Freestanding Office Buildings; Converted Dwellings; Restaurants; Service Stations, etc.
Institutional	Airports; Federal; Provincial and Municipal Assets; School Sites; Utility Easements and Right of Ways; Utility Buildings; Transportation Facilities; Landfill Sites; Transmission Tower Sites; Well and Water Tower Sites, etc.
Agricultural	Hobby Farms; Land
Unique	Large Tracts; Large Institutional Buildings; Education Development Charges.
Consulting	Expropriation; Peer Review; Education Development Charges; Alternative – Valuations
Government Consulting	Road Widening and Easement Projects; Sale of Municipal or Surplus Land; Land Acquisition; Conservation Easements, Eco Gift Valuations, Environmental Acquisition's, etc.

23.0 Assumptions, Limiting Conditions, Disclaimers and Limitations of Liabilities

The certification that appears in this report is subject to compliance with the Personal Information and Electronics Documents Act (PIPEDA), Canadian Uniform Standards of Professional Appraisal Practice ("CUSPAP") and the following conditions:

1. This report is prepared only for the client and authorized users specifically identified in this report and only for the specific use identified herein. No other person may rely on this report or any part of this report without first obtaining consent from the client and written authorization from the authors. Liability is expressly denied to any other person and, accordingly, no responsibility is accepted for any damage suffered by any other person as a result of decisions made or actions taken based on this report. Liability is expressly denied for any unauthorized user or for anyone who uses this report for any use not specifically identified in this report. Payment of the appraisal fee has no effect on liability. Reliance on this report without authorization or for an unauthorized use is unreasonable.

2. Because market conditions, including economic, social and political factors, may change rapidly and, on occasion, without warning, this report cannot be relied upon as of any date other than the effective date specified in this report unless specifically authorized by the author(s).

3. The author will not be responsible for matters of a legal nature that affect either the property being appraised or the title to it. The property is appraised on the basis of it being under responsible ownership. No registry office search has been performed and the author assumes that the title is good and marketable and free and clear of all encumbrances. Matters of a legal nature, including confirming who holds legal title to the appraised property or any portion of the appraised property, are outside the scope of work and expertise of the appraiser. Any information regarding the identity of a property's owner or identifying the property owned by the listed client and/or applicant provided by the appraiser is for informational purposes only and any reliance on such information is unreasonable. Any information provided by the appraiser does not constitute any title confirmation. Any information provided does not negate the need to retain a real estate lawyer, surveyor or other appropriate experts to verify matters of ownership and/or title.

4. Verification of compliance with governmental regulations, bylaws or statutes is outside the scope of work and expertise of the appraiser. Any information provided by the appraiser is for informational purposes only and any reliance is unreasonable. Any information provided by the appraiser does not negate the need to retain an appropriately qualified professional to determine government regulation compliance.

5. No survey of the property has been made. Any sketch in this report shows approximate dimensions and is included only to assist the reader of this report in visualizing the property. It is unreasonable to rely on this report as an alternative to a survey, and an accredited surveyor ought to be retained for such matters.

6. This report is completed on the basis that testimony or appearance in court concerning this report is not required unless specific arrangements to do so have been made beforehand. Such arrangements will include, but not necessarily be limited to: adequate time to review the report and related data, and the provision of appropriate compensation.

7. Unless otherwise stated in this report, the author has no knowledge of any hidden or unapparent conditions (including, but not limited to: its soils, physical structure, mechanical or other operating systems, foundation, etc.) of/on the subject property or of/on a neighbouring property that could affect the value of the subject property. It has been assumed that there are no such conditions. Any such conditions that were visibly apparent at the time of inspection or that became apparent during the normal research involved in completing the report have been noted in the report. This report should not be construed as an environmental audit or detailed property condition report, as such reporting is beyond the scope of this report and/or the qualifications of the author. The author makes no guarantees or warranties, express or implied, regarding the condition of the property, and will not be responsible for any such conditions that do exist or for any engineering or testing that might be required to discover whether such conditions exist. The bearing capacity of the soil is assumed to be adequate.

8. The author is not qualified to comment on detrimental environmental, chemical or biological conditions that may affect the market value of the property appraised, including but not limited to pollution or contamination of land, buildings, water, groundwater or air which may include but are not limited to moulds and mildews or the conditions that may give rise to either. Any such conditions that were visibly apparent at the time of inspection or that became apparent during the normal research involved in completing the report have been noted in the report. It is an assumption of this report that the property complies with all regulatory requirements concerning environmental, chemical and biological matters, and it is assumed that the property is free of any detrimental environmental, chemical legal and biological conditions that may affect the market value of the property appraised. If a party relying on this report requires information or an assessment of detrimental environmental, chemical or biological conditions that may impact the value conclusion herein, that party is advised to retain an expert qualified in such matters. The author expressly denies any legal liability related to the effect of detrimental environmental, chemical or biological matters on the market value of the property.

9. The analyses set out in this report relied on written and verbal information obtained from a variety of sources the author considered reliable. Unless otherwise stated herein, the author did not verify client-supplied information, which the author believed to be correct.

10. The term “inspection” refers to observation only as defined by CUSPAP and reporting of the general material finishing and conditions observed for the purposes of a standard appraisal inspection. The inspection scope of work includes the identification of marketable characteristics/amenities offered for comparison and valuation purposes only.

11. The opinions of value and other conclusions contained herein assume satisfactory completion of any work remaining to be completed in a good and workmanlike manner. Further inspection may be required to confirm completion of such work. The author has not confirmed that all mandatory building inspections have been completed to date, nor has the availability/issuance of an occupancy permit been confirmed. The author has not evaluated the quality of construction, workmanship or materials. It should be clearly understood that this visual inspection does not imply compliance with any building code requirements as this is beyond the professional expertise of the author.

12. The contents of this report are confidential and will not be disclosed by the author to any party except as provided for by the provisions of the CUSPAP and/or when properly entered into evidence of a duly qualified judicial or quasi-judicial body. The author acknowledges that the information collected herein is personal and confidential and shall not use or disclose the contents of this report except as provided for in the provisions of the CUSPAP and in accordance with the author’s privacy policy. The client agrees that in accepting this report, it shall maintain the confidentiality and privacy of any personal information contained herein and shall comply in all material respects with the contents of the author's privacy policy and in accordance with the PIPEDA.

13. The author has agreed to enter into the assignment as requested by the client named in this report for the use specified by the client, which is stated in this report. The client has agreed that the performance of this report and the format are appropriate for the intended use.

14. This report, its content and all attachments/addendums and their content are the property of the author. The client, authorized users and any appraisal facilitator are prohibited, strictly forbidden, and no permission is expressly or implicitly granted or deemed to be granted, to modify, alter, merge, publish (in whole or in part) screen scrape, database scrape, exploit, reproduce, decompile, reassemble or participate in any other activity intended to separate, collect, store, reorganize, scan, copy, manipulate electronically, digitally, manually or by any other means whatsoever this appraisal report, addendum, all attachments and the data contained within for any commercial, or other, use.

15. If transmitted electronically, this report will have been digitally signed and secured with personal passwords to lock the appraisal file. Due to the possibility of digital modification, only originally signed reports and those reports sent directly by the author can be reasonably relied upon.

16. This report form is the property of the Appraisal Institute of Canada (AIC) and for use only by AIC members in good standing. Use by any other person is a violation of AIC copyright.

17. Where the intended use of this report is for financing or mortgage lending or mortgage insurance, it is a condition of reliance on this report that the authorized user has or will conduct lending, underwriting and insurance underwriting and rigorous due diligence in accordance with the standards of a reasonable and prudent lender or insurer, including but not limited to ensuring the borrower's demonstrated willingness and capacity to service his/her debt obligations on a timely basis, and to conduct loan underwriting or insuring due diligence similar to the standards set out by the Office of the Superintendent of Financial Institutions (OSFI), even when not otherwise required by law. Liability is expressly denied to those that do not meet this condition. Any reliance on this report without satisfaction of this condition is unreasonable.

18. All copyright is reserved to the author and this report is considered confidential by the author and the client. Possession of this report, or a copy thereof, does not carry with it the right to reproduction or publication in any manner, in whole or in part, nor may it be disclosed, quoted from or referred to in any manner, in whole or in part, without prior written consent and approval of the author as to the purpose, form and content of any such disclosure, quotation or reference. Without limiting the generality of the foregoing, neither all nor any part of the contents of this report shall be disseminated or otherwise conveyed to the public in any manner whatsoever or through any media whatsoever or disclosed, quoted from or referred to in any report, financial statement, prospectus, or offering memorandum of the client, or in any documents filed with any governmental agency without the prior written consent and approval of the author as to the purpose, form and content of such dissemination, disclosure, quotation or reference. This is subject only to confidential review by the Appraisal Institute of Canada as provided in the Canadian Uniform Standards of Professional Appraisal Practice.

24.0 Certification

I certify that, to the best of my knowledge and belief that:

1. The statements of fact contained in this report are true and correct;
2. The reported analyses, opinions and conclusions are limited only by the reported assumptions and limiting conditions and are my impartial and unbiased professional analyses, opinions and conclusions;
3. I have no past, present or prospective interest in the property that is the subject of this report and no personal and/or professional interest or conflict with respect to the parties involved with this assignment.
4. I have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment;
5. My engagement in and compensation is not contingent upon developing or reporting predetermined results, the amount of value estimate, a conclusion favouring the client, or the occurrence of a subsequent event.
6. My analyses, opinions and conclusions were developed, and this report has been prepared, in conformity with the CUSPAP.
7. I have the knowledge and experience to complete this assignment competently, and where applicable this report is co-signed in compliance with CUSPAP;
8. Except as herein disclosed, no one has provided significant professional assistance to the person(s) signing this report;
9. As of the date of this report the undersigned has fulfilled the requirements of the AIC's Continuing Professional Development Program;
10. The undersigned is (are all) members in good standing of the Appraisal Institute of Canada.

Property Identification

Address:	680 Beaverhall Place, Thunder Bay, ON
Legal Description:	Lot 13, Plan W796, (Neebing), City of Thunder Bay

Based upon the data, analyses and conclusions contained herein, the Market Value of the interest in the property described:

As at July 28, 2021 is estimated at $2,300,000 (amount in Canadian dollars).

Any Extraordinary Assumptions, Hypothetical Conditions and/or Extraordinary Limiting Conditions are noted in Section 6.0.

As set out elsewhere in this report, this report is subject to certain assumptions and limiting conditions, the verification of which is outside the scope of this report.

Appraisal Institute of Canada Appraiser

DRAFT

Signature: ____________________
Name: Peter Spivey, B.Sc, AACI, P.App, 904444
Date of Report:
Personally, Inspected the Subject Property Yes
Date of Inspection: July 28, 2021
Source of digital signature security: Password Protected PDF Document
Note: For this appraisal to be valid, an original or a digital signature is required and the document is to be password protected from modification.

Attachments and Addenda Items:

- Parcel Register
- Detailed Land Comparable Sales and Sales Location Maps
- Detailed Improved Comparable Sales and Sales Location Maps

25.0 Addenda

25.1 Parcel Register
25.2 Detailed Comparable Land Sales and Sales Location Maps
25. 3 Detailed Comparable Sales and Sales Location Maps

25.1 Parcel Register

Ontario ServiceOntario

LAND REGISTRY OFFICE #55

PARCEL REGISTER (ABBREVIATED) FOR PROPERTY IDENTIFIER

62043-0045 (LT)

* CERTIFIED IN ACCORDANCE WITH THE LAND TITLES ACT * SUBJECT TO RESERVATIONS IN CROWN GRANT *

PAGE 1 OF 1
PREPARED FOR aicSThomp7
ON 2021/08/16 AT 14:19:56

GEOWAREHOUSE

PROPERTY DESCRIPTION: LT 13 PL W796 NEEBING; THUNDER BAY

PROPERTY REMARKS:

ESTATE/QUALIFIER:
FEE SIMPLE
LT CONVERSION QUALIFIED

RECENTLY:
FIRST CONVERSION FROM BOOK

PIN CREATION DATE:
2004/03/29

OWNERS' NAMES
ONTARIO HYDRO

CAPACITY SHARE
BENO

REG. NUM.	DATE	INSTRUMENT TYPE	AMOUNT	PARTIES FROM	PARTIES TO	CERT/ CHKD
** PRINTOUT INCLUDES ALL DOCUMENT TYPES AND DELETED INSTRUMENTS SINCE 2004/03/26 **						
**SUBJECT, ON FIRST REGISTRATION UNDER THE LAND TITLES ACT, TO:						
** SUBSECTION 44(1) OF THE LAND TITLES ACT, EXCEPT PARAGRAPH 11, PARAGRAPH 14, PROVINCIAL SUCCESSION DUTIES *						
** AND ESCHEATS OR FORFEITURE TO THE CROWN.						
** THE RIGHTS OF ANY PERSON WHO WOULD, BUT FOR THE LAND TITLES ACT, BE ENTITLED TO THE LAND OR ANY PART OF						
** IT THROUGH LENGTH OF ADVERSE POSSESSION, PRESCRIPTION, MISDESCRIPTION OR BOUNDARIES SETTLED BY						
** CONVENTION.						
** ANY LEASE TO WHICH THE SUBSECTION 70(2) OF THE REGISTRY ACT APPLIES.						
**DATE OF CONVERSION TO LAND TITLES: 2004/03/29 **						
OFW50314	1965/05/07	ORDER IN COUNCIL				C
REMARKS: AMENDS LAKEHEAD AIRPORT ZONING REGULATIONS * DOCUMENT TYPE CHANGED FROM BYLAW TO ORDER-IN-COUNCIL ON JANUARY 16, 2007 W.LITTLE *						
OFW68098	1970/07/22	BYLAW				C
TBR253659	1984/03/09	ASSIGNMENT LEASE			GUARANTY TRUST CO. OF CANADA CAPITAL EQUIPMENT INC.	C
TBR299917	1988/09/26	TRANSFER	$525,000		ONTARIO HYDRO	C

NOTE: ADJOINING PROPERTIES SHOULD BE INVESTIGATED TO ASCERTAIN DESCRIPTIVE INCONSISTENCIES, IF ANY, WITH DESCRIPTION REPRESENTED FOR THIS PROPERTY.
NOTE: ENSURE THAT YOUR PRINTOUT STATES THE TOTAL NUMBER OF PAGES AND THAT YOU HAVE PICKED THEM ALL UP.
NOTE: RESULTS WERE GENERATED VIA WWW.GEOWAREHOUSE.CA

25.2 Detailed Land Sales and Land Sales Location Maps

COMPARABLE#: 1

Address:	645 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$325,000.00
Sale $/Unit:	$179,558 per acre
Sale Date:	Nov 26, 2020
Pin #	620430091
Vendor	948825 Ontario Inc.
Purchaser	Sparcon Construction Inc.
Roll Number	580404020102500

SITE INFORMATION

Lot Area:	1.81	acres	**Frontage:**	322	**Zoning**	IN2- Medium Industrial
Location:	Interior		**Services:**	Full	**OP:**	Industrial

Legal Description Lot 17 Plan W796,Neebing; City of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 2

Address:	600 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$250,000.00
Sale $/Unit:	$160,256 per acre
Sale Date:	Dec 04, 2020
Pin #	620430043
Vendor	Pepco Tbay Inc.
Purchaser	2786341 Ontario Ltd.
Roll Number	580404020103900

SITE INFORMATION

Lot Area:	1.56	acres	**Frontage:**	170	**Zoning**	ID2- Medium Industrial
Location:	Corner		**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 6 on Plan W796, Neebing Part 1, 55R10259; in the city of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is located at the intersection of Beaverhall Place and Mountdaye Avenue. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 3

Address:	685 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$300,000.00
Sale $/Unit:	$348,837 per acre
Sale Date:	Jun 25, 2021
Pin #	620430053
Vendor	Grant Equipment Corp.
Purchaser	539804 Ontario Inc.
Roll Number	580404020113105

SITE INFORMATION

Lot Area:	0.86	acres	**Frontage:**	127	**Zoning**	IN1- Light Industrial
Location:	Interior		**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 20 on Plan W796, Neebing; Part Stanley Ave. on Plan QW796 Neebing, Closed by TBR413183, Part 1 and 2 on 55R7794; Subject to Right in TBR221127; in the city of Thunder Bay

Parcel of a small parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site was reportedly acquired by a nearby user to develop an industrial facility. This site was cleared and generally level and used as a storage yard at the time of the sale. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 4

Address:	625 Mountdale Ave.
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$167,000.00
Sale $/Unit:	$115,172 per acre
Sale Date:	May 04, 2016
Pin #	620430089
Vendor	Not Available
Purchaser	Mahon Electric Company Limitedà
Roll Number	580404020104000

SITE INFORMATION

Lot Area:	1.45	acres	**Frontage:**	244		**Zoning**	ID2- Medium Industrial
Location:	Interior		**Services:**	Full		**OP:**	Industrial

Legal Description Part of Lot 7 on Plan W796, Neebing, Parts 1 and 2 on Plan 55R14039, Subject to an Easement in Gross over Part 2 on Plan 55R14039 as in TY214023, in the city of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area), fronting the west side of Mountdale Avenue. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 5

Address:	625 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$300,000.00
Sale $/Unit:	$177,515 per acre
Sale Date:	Sep 09, 2014
Pin #	620430049
Vendor	Royal Host GP Inc.
Purchaser	1383793 Ontario Inc.
Roll Number	580404020102600

SITE INFORMATION

Lot Area:	1.69	acres	**Frontage:**	300	**Zoning**	C3- Highway Com.
Location:	Interior		**Services:**	Full	**OP:**	Commercial

Legal Description Part of Lot 16 on Plan W796 Neebing as in TBR341227 as ammended by TBR394415 except the Easement therein; Part of Block A on Plan 864 Neebing, Part 1 and 2 on 55R8957; Subject to TBR341227 and OFW54411; in the city of Thunder Bay

Parcel of commercial designated land located in a primarily industrial area known as the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is located adjoining an older motel and formerly formed part of the parking lot. Although designated commercial some opportunity may be present for conversion to an industrial type use. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 6

Address: 295 Court Street S.

Municipality: Thunder Bay

Community: n/a

Sale Price: $1,150,000.00

Sale $/Unit: $330,460 per acre

Sale Date: Jul 30, 2021

Pin # 621260078 & 621260074

Vendor Arnone Transport Limited

Purchaser Not Yet Registered

Roll Number 580401003503600 & *

SITE INFORMATION

Lot Area:	3.48	acres	**Frontage:**	409	**Zoning**	IN2- Medium Com.
Location:	Interior		**Services:**	Full	**OP:**	Industrial

Legal Description Part Lot 1-4 Block 35on Plan 147 McIntyre; Part Lot 49-51, 54-55, 57 Plan 572 McIntyre Part 3 & 4, 55R10246; T/W TBR413511; Subject to PTA141390; Subject toTBR284105, TBR398827; in the city of Thunder Bay & **

Sale of a good quality parcel of employment land located centrally in Thunder Bay. This site had exposure to Water Street, a 4 lane arterial road and is on the fringe of the downtown core. The site is cleared and generally level and appears to have been utilized for trailer parking / storage.

MLS Sale Date: 06/25/2021

* 580401003500910
**Lots 73,75,77,79 & Part of Lots 54,56,58,80,81,82 & Part Inchiquin Street Closed by TBR163865, on Plan 572 AND Part Lots 2,3,4 & Part Lane Closed by TBR163865 & Part 0.30 Reserve Block 35 on Plan 147 Being Parts 1 & 5 55R12031 & Parts 7 & 8 55R10246 ; Thunder Bay ; Subject to Easements TBR438725,F128620,F132236 on Part 5 Plan 55R12031; in the city of Thunder Bay.

COMPARABLE#: 7

Address: 0 Dunlop Street
Municipality: Thunder Bay
Community: n/a
Sale Price: $151,000.00
Sale $/Unit: $138,532 per acre
Sale Date: Mar 18, 2021
Pin # 620790552 & 620790507
Vendor Not Available
Purchaser 1648822 Ontario Ltd.
Roll Number 580401003732800

SITE INFORMATION

Lot Area:	1.09	acres	**Frontage:**	200	**Zoning:**	IN2- Medium Ind.
Location:	Interior		**Services:**	Full	**OP:**	Commercial

Legal Description Lots 132-136 on Plan M52 and Part Brandon Avenue, Plan M52 Closed by LT136601, Part 5 on 55R14780; in the city of Thunder Bay & Part Brandon Avenue on Plan M52 Closed by LT136601, Part 4 on 55R14780; in the city of Thunder Bay

Small parcel of industrial land located centrally within Thunder Bay. This site was treed and required clearing and some fill to allow for development.

COMPARABLE#: 8

Address: 224 Burwood Rd
Municipality: Thunder Bay
Community: n/a
Sale Price: $399,900.00
Sale $/Unit: $141,307 per acre
Sale Date: Jan 15, 2020
Pin # 621170020
Vendor Daniel Clara
Purchaser Reliable Northern Developments Ltd.
Roll Number 580402010108000

SITE INFORMATION

Lot Area:	2.83 acres	**Frontage:**	248	**Zoning**	IN6- Prestige Ind.
Location:	Interior	**Services:**	Full in Area	**OP:**	Industrial

Legal Description Part of Lot 19 on Plan 760 McIntyre as in TBR215580; city of Thunder Bay

Parcel of industrial land located in the central portion of Thunder Bay, slightly east of Highway 17. The site was forested and required clearing and some grading / fill works. It is our understanding that full municipal services are in the area.

Land Sales Location Maps

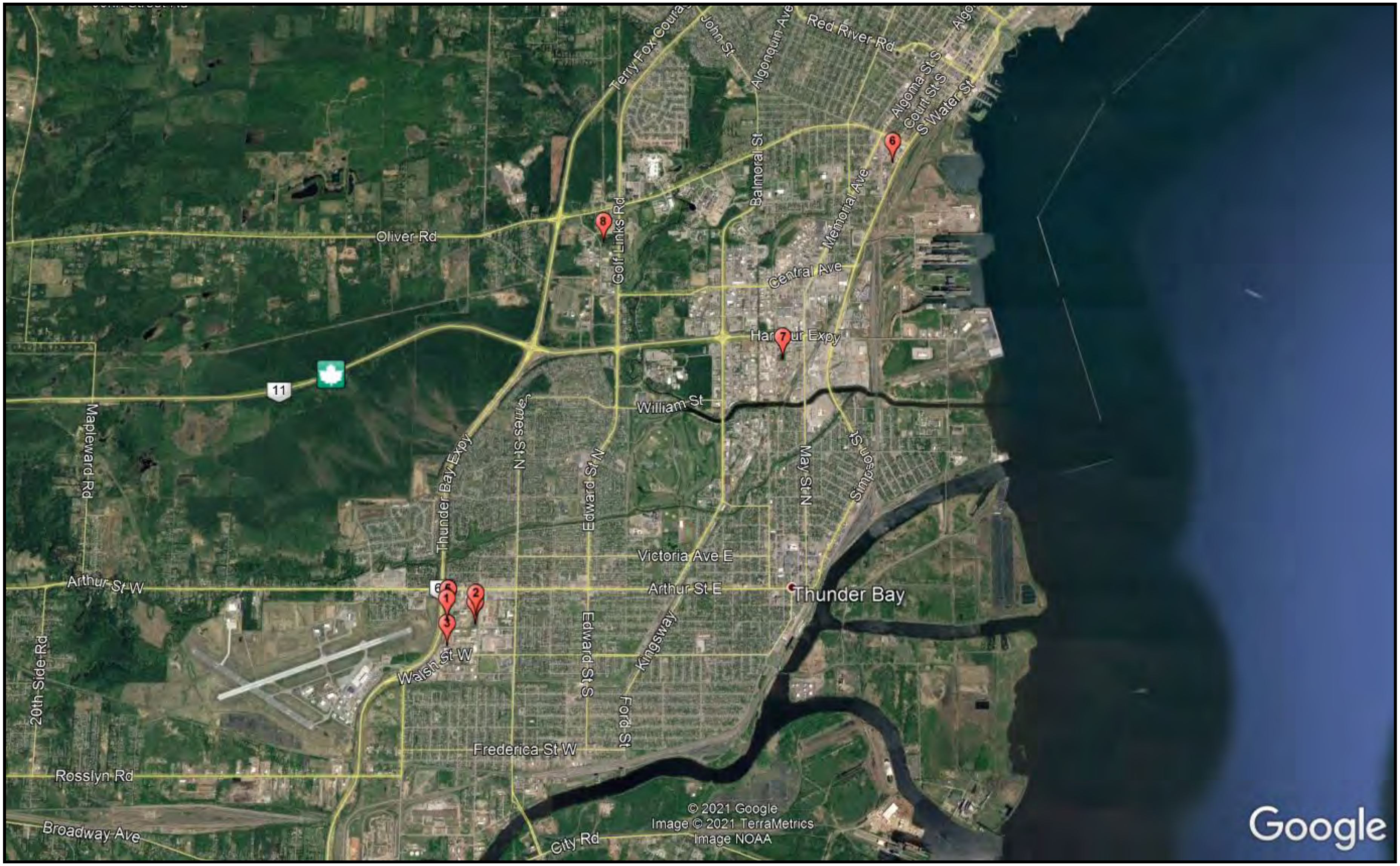


Figure 14 Source: Google Earth

Figure 15 Source: Google Earth

25.3 Detailed Comparable Sales and Sales Location Maps

COMPARABLE#: 1

Service Industrial

Address:	1400 Walsh St. West
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$1,300,000.00
Sale $/Unit:	$ 130 / sq. ft.
Sale Date:	Apr 30, 2021
Pin #	620420023 & 620420022
Vendor	4249739 Canada Inc.
Purchaser	Wildon Wiring Limited
Roll Number	580404020116400

SITE INFORMATION

Lot Area:	3.50	acres	**Services:**	Full
Location:	Corner		**Type:**	IND
Surplus Land:	Yes		**Prop Code:**	540
Zoning:	Med. Industrial			
Zoning OP:	Industrial			

BUILDING INFORMATION

Area:	10,001	sq.ft.
Age:	1973	
Units:	1	

Sale of a former Cummings sales and service facility that is now utilized by an industrial user as a service shop. The property included a large yard area. The building appears to be in average to good condition with a reported 5,610 sq.ft. of office / showroom area.

COMPARABLE#: 2

Industrial

Address:	1210 Commerce Street
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$1,100,000.00
Sale $/Unit:	$178/ sq. ft
Sale Date:	Dec 18, 2020
Pin #	6204020012 & 620420008 *
Vendor	Wildon Wiring Limited
Purchaser	Emcon Services Inc.
Roll Number	580404020117110 & **

SITE INFORMATION

Lot Area:	2.29	acres	**Services:**	Full
Location:	Interior		**Type:**	IND
Surplus Land:	Yes		**Prop Code:**	540
Zoning:	Med. Industria l			
Zoning OP:	Industrial			

BUILDING INFORMATION

Area:	6,170	sq.ft.
Age:	1978	
Units:	1	

Sale of an industrial property improved with a roughly 6,100 sq.ft. industrial building situated on 2.29 acre site. The building is reported to include 1,800 sq.ft. of office, 3,600 sq.ft. of service industrial area and 970 sq.ft. of storage space with lower ceilings. The building is a steel building that appears to be in modest to average condition. The site provides for a large fenced gravel yard.

*620420007, 620420008, 620420009, 620420012
** 580404020116700

We note that the property sold on MLS in August 2020 for a price of $849,000. This transaction does not appear to have closed and the property resold as outlined in December 2020.

COMPARABLE#: 3

Industrial

Address: 1230 Carrick Street

Municipality: Thunder Bay

Community: n/a

Sale Price: $1,950,000.00

Sale $/Unit: $93 / sq. ft

Sale Date: Aug 14, 2020

Pin # 620790071 & 620790072

Vendor 1876009 Ontario Inc.

Purchaser Trevlind Investments Limited

Roll Number 580401003787900 & *

SITE INFORMATION

Lot Area:	3.73 acres	**Services:**	Full
Location:	Interior	**Type:**	IND
Surplus Land:	Yes	**Prop Code:**	520
Zoning:	Medium Indus trial		
Zoning OP:	Industrial		

BUILDING INFORMATION

Area: 21,065 sq.ft.

Age: n/a

Units:

The property was improved with an older industrial building that appears to be in average condition. The reported size was approximately 21,065 sq.ft.. along with an estimated office area of 5,600 sq.ft. +/-. Also noted was a separate small cold storage building. The site includes a large fenced yard. With regard to location, the property is situated in a desirable general area, i.e. Intercity, but is only fair with respect to its specific setting recognizing its somewhat removed location at the end of Carrick Street abutting the Neebing/McIntyre floodway.

* 580401003787900

COMPARABLE#: 4

Industrial

Address:	605 Hewitson Street
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$2,750,000.00
Sale $/Unit:	$142 / sq.ft.
Sale Date:	Jan 06, 2021
Pin #	6207900013 & 620790014
Vendor	DST Technologies Inc.
Purchaser	1401285 Ontario Inc.
Roll Number	58040003788315

SITE INFORMATION

Lot Area:	2.35 acres	**Services:**	Full
Location:	Corner	**Type:**	IND
Surplus Land:	No	**Prop Code:**	520
Zoning:	Light Ind.		
Zoning OP:	Industrial		

BUILDING INFORMATION

Area:	19,314 sq.ft
Age:	n/a
Units:	3

Sale of two adjoining properties improved with a total of 3 buildings. The bindings have a total area of approximately 19,310 sq.ft. and include two steep clad industrial buildings and a brick and siding clad service commercial / office building. The steel buildings appear to be in average condition while the brick clad building appears to be in good condition. Some of the buildings appeared to be tenanted at the time of the sale. The site provide for a paved parking area and a gravel yard area.

MLS sale Date: Nov 13, 2020

COMPARABLE#: 5

Industrial

Address:	879 Tungsten Street
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$1,400,000.00
Sale $/Unit:	$84 / sq.ft.
Sale Date:	Nov 01, 2018
Pin #	621220254 621220255
Vendor	2017506 Ontario Ltd.
Purchaser	LW Holdings Ltd.
Roll Number	580401003231600

SITE INFORMATION

Lot Area:	1.68 acres	**Services:**	Full
Location:	Interior	**Type:**	IND
Surplus Land:	No	**Prop Code:**	520
Zoning:	Medium Ind.		
Zoning OP:	Industrial		

BUILDING INFORMATION

Area:	16,600 sq.ft.
Age:	n/a
Units:	1

Sale of an approximately 16,660 sq.ft. one-storey non-clear span industrial building. It was originally developed for use in conjunction with a retail lumber yard, circa late 1980s/early 1990s. The building was constructed in stages with the current building representing essentially an open shell with concrete floors and painted drywall walls & ceilings that is reported to be in good overall condition. The presence of attractive main floor office space of approx. 1600 sq.ft., with a similar amount of 2nd floor partially finished mezzanine for use as storage and an employees' lunchroom is reported. The site includes a fenced side yard and rear yard area.

COMPARABLE#: 6

Office

Address: 544 Winnipeg Ave.

Municipality: Thunder Bay

Community: n/a

Sale Price: $1,200,000.00

Sale $/Unit: $120 / sq. ft.

Sale Date: Dec 17, 2018

Pin # 621220164 621220165 621220166
° *

Vendor Sandpaul Investments Limited

Purchaser 1778705 Ontario Ltd.

Roll Number 580401003625700

SITE INFORMATION

Lot Area: 0.66 acres

Services: Full

Location: Interior

Type: OFF

Surplus Land: No

Prop Code: 400

Zoning: C4-A

Zoning OP: Commercial

BUILDING INFORMATION

Area: 10,003 sq.ft.

Age: n/a

Units: 1

Sale of an entry level office building that appears to be utilized by a community group. The building is a single storey steel and brick clad structure that appears to be in average condition. The site provides paved parking on the north and south side of the building. The property is located near Memorial Ave, a busy arterial road.

* 621220167

COMPARABLE#: 7

Office

Address: 1204 Roland Street

Municipality: Thunder Bay

Community: n/a

Sale Price: $1,025,000.00

Sale $/Unit: $101/ sq. ft.

Sale Date: Feb 19, 2019

Pin # 620790024

Vendor 1526454 Ontari Limited

Purchaser 1526152 Ontario Inc.

Roll Number 580401003751500

SITE INFORMATION

Lot Area: 0.98 acres

Location: Corner

Surplus Land: No

Zoning: Light Ind.

Zoning OP: Industrial

Services: Full

Type: OFF

Prop Code: 402

BUILDING INFORMATION

Area: 10,128 sq.ft.

Age: 1976

Units: 3

Sale of a multi-tenant office building located at the intersection of Roland Street and Balmoral Street. This building has a decorative concrete block construction, built in the 1970's. The site provides a paved parking lot. Overall the property and building appears to be in average condition.

Sales Location Maps

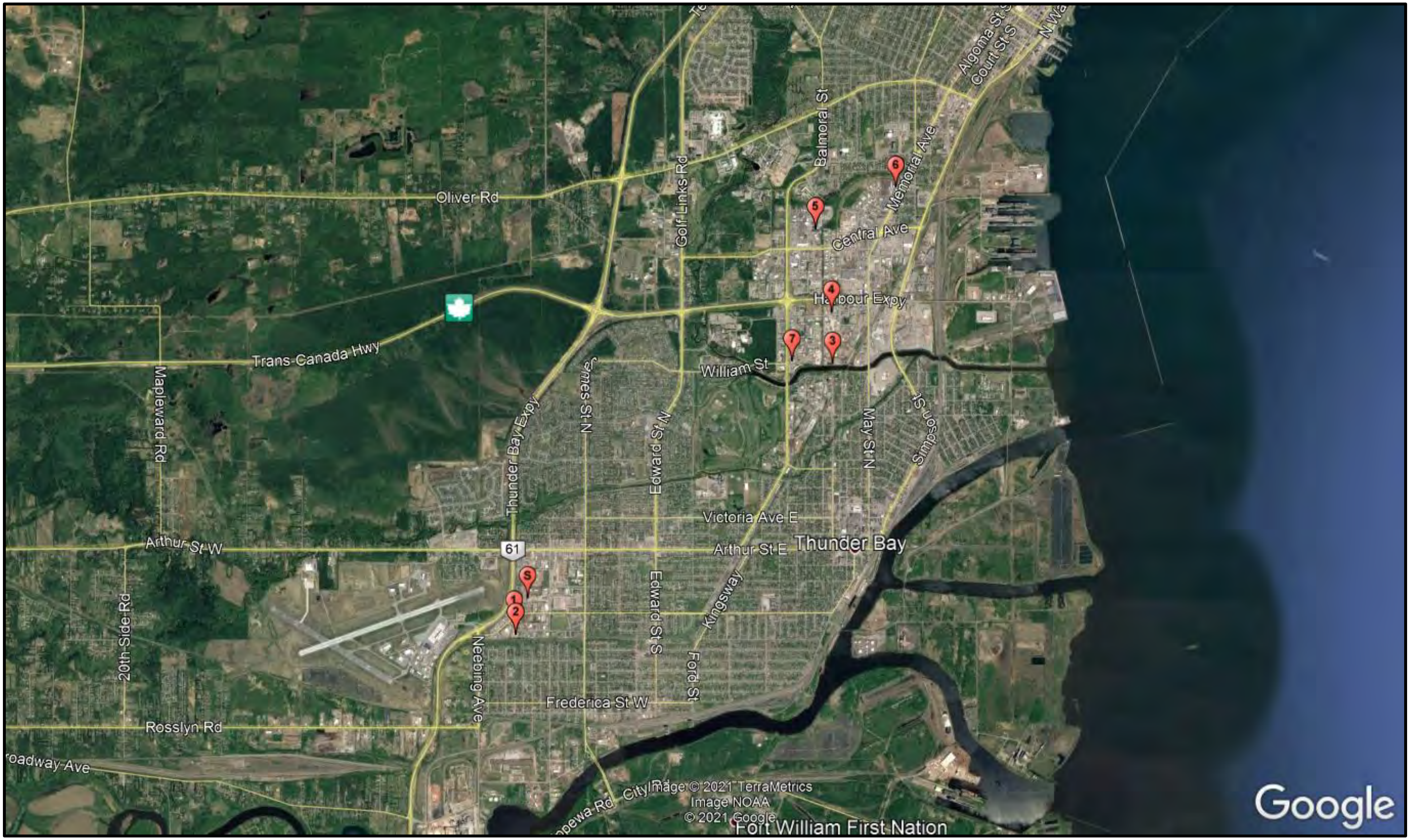


Figure 16 Source: Google Earth

Figure 17 Source: Google Earth

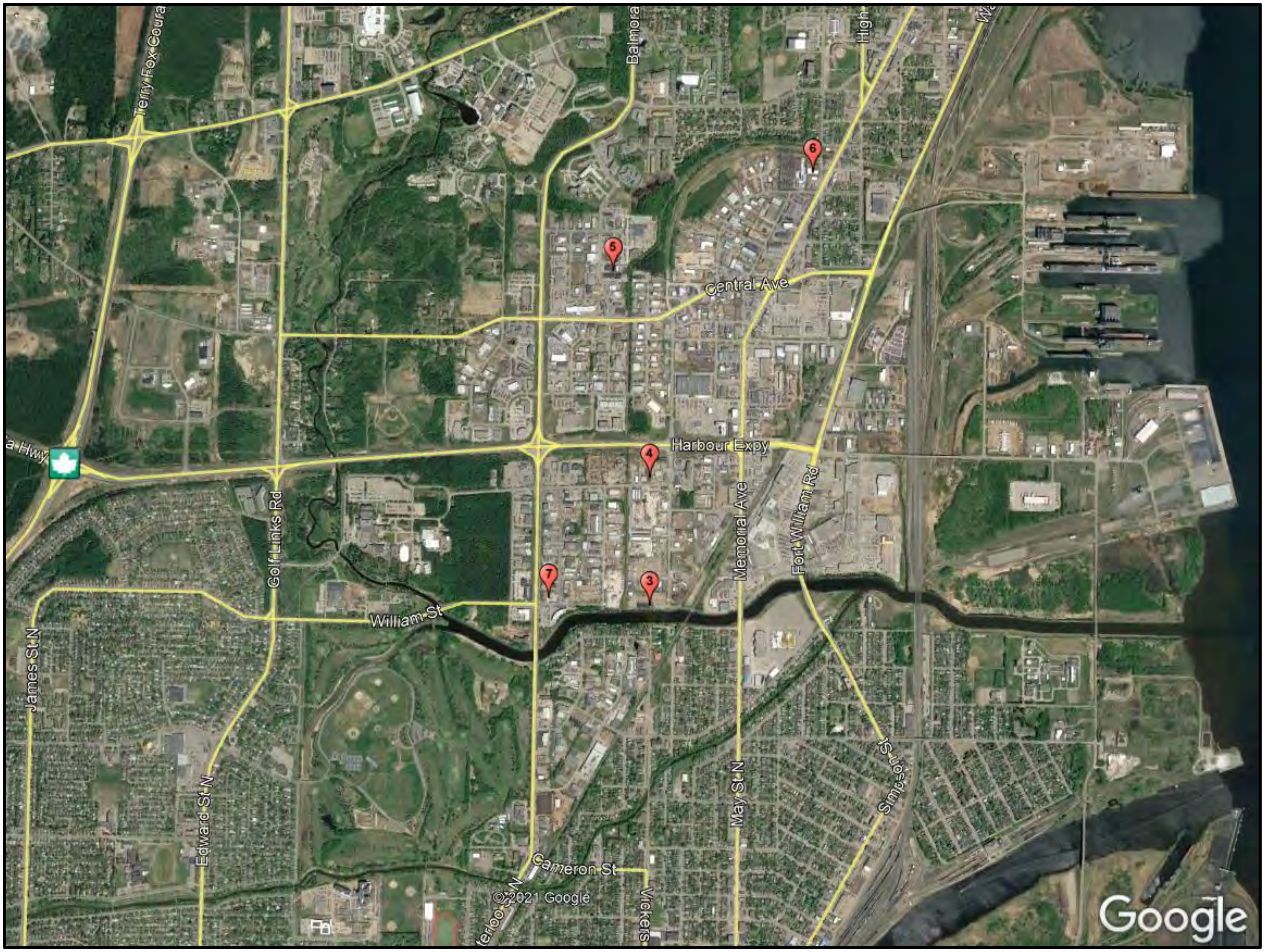


Figure 18 Source: Google Earth

ATTACHMENT 4:

REPORT OF ALTERNATE BUILDING / SITE OPPORTUNITIES

Real Estate Advisors

CONSULTING REPORT OF

Hydro One Remote Communities Inc.
Alternate Building / Site Opportunities
Thunder Bay, ON

PREPARED FOR

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

ANDREW, THOMPSON
& ASSOCIATES LTD.

177 Dunlop Street West
Barrie, ON L4N 1B4
PHONE 705-721-1596 FAX 705-721-5183
WEB www.andrew-thompson.on.ca

August 17, 2021

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

Attention: Mr. Keith Barr

Re: HONI Remote Communities - Alternate Building / Site Opportunities

Dear Mr. Barr:

Further to your request, we provide this consulting report addressing the site / building availability search for a new Hydro One Remote Communities facility in the Thunder Bay Market. We have thoroughly considered your requirements as outlined in the RFP. This report has been prepared based on our understanding of the identified criteria.

Further to your instructions, we have conducted a market investigation for properties available or suitable for the acquisition and development of a new Hydro One Remote Communities facility. The alternatives are based on a variety of site / building criteria within the provided geographic boundaries identified within the RFP.

We do not have any conflicts of interest to disclose which emerged from the work completed to date.

This consulting report is intended to be consistent with the Terms of Reference and in accordance with the Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) adopted by the Appraisal Institute of Canada.
.

TABLE OF CONTENTS

1.0 Study Framework

Hydro One Remote Communities Inc. (herein referred to as Remotes) is searching for an alternate location to establish a new facility to replace the existing facility found at 680 Beaverhall Place, Thunder Bay. This market investigation identifies properties available for the acquisition and development of a facility or an existing facility based on a variety of site criteria within a pre-selected geographic boundary.

The current facility at 680 Beaverhall Place, City of Thunder Bay, which provides for administrative, shop, warehouse and outdoor storage functions is no longer considered suitable to meet Remotes operational requirements and this site / building opportunity study is in support of the search for a property to develop a new facility.

We have been requested to address the following items with this study:

1. Available sites for a new development opportunity.
2. Available existing facilities.
3. Benchmark land value within the immediate neighbourhood proximity of the existing facility at 680 Beaverhall Place.

1.1 General Site Requirement Characteristics

The client has provided the following general guidelines with regard to an existing / development opportunity.

> *With the high dependency of the operations for flight support, the preferred siting of a new Operations Centre would be in close proximity to the Thunder Bay International Airport (the "Airport"). This spatial relationship does not have an absolute requirement, such as time and distance, but preference would be given to equivalent properties / developments that optimize this relationship.*
>
> *As to physical siting in proximity to the Airport, there are no operational activities of concern. As an example, the Operations Centre does not include or use high mast structures or cranes as part of its development and operations, which would be restricted within flight path corridors.*

1.2 Geographic Boundaries

Generally, the study area is to be within a 5 km distance from the Thunder Bay International Airport. Our research has been expanded to include the entire City of Thunder Bay and the immediate surrounding areas.

1.3 Essential Site Criteria

The following outlines the provided ideal criteria:

- Site area of no less than 5 acres.
- Full municipal services, including water, sanitary, gas, hydro and

telecommunications.
- Convenient access to major transportation routes.
- Less than 5 kilometers to the Thunder Bay International Airport.
- Permit a building program of up to 30,000 square feet.
- Building program reflecting flex-industrial space to accommodate the aforementioned space requirements.
- Parking for 40+ staff and visitors.
- Proximity to hotels and food services, less than 5 kilometers.

1.4 Essential Building Criteria – Existing Facility

The client has not provided specific building criteria for existing facilities to be considered. We have been provided with a preliminary list of upgrade requirements relative to the existing facility and we have discussed the needs with Mr. Barr. Based on these guidelines we have completed a search for existing facilities.

2.0 Basis of the Report

Client – The Client for this file is Hydro One Remote Communities Inc

The Intended User(s) - This report is intended for use only by Hydro One Remote Communities Inc

Purpose / Intended Use of the Report - The purpose / intended use of this consulting report is to assist with determining available development opportunities in the Thunder Bay Market.

We have not applied a Jurisdictional Exception in the preparation of this report.

2.1 Terms of Reference

At the request of The Hydro One Remotes Communities Inc., Andrew, Thompson & Associates Ltd. was instructed to:

- Identify available sites that meet the provided criteria.
- Identify available existing facilities that would suit Remotes needs.
- Provide a benchmark land value for sites within the immediate neighbourhood/ proximity of the existing facility at 680 Beaverhall Place.

2.2 Extraordinary Assumptions, Hypothetical Conditions and Limiting Conditions

Extraordinary Assumptions

An extraordinary assumption refers to an assumption, directly related to a specific assignment, which, if found to be false, could materially alter the opinions or conclusions.

- We note that all referenced sites are assumed to be free of contamination unless otherwise noted.

Hypothetical Conditions

A hypothetical condition is that which is contrary to what exists, but is supposed to exist for the purpose of analysis.

- None

Extraordinary Limiting Condition

An extraordinary condition is a necessary modification or exclusion of a Standard Rule which may diminish the reliability of the report.

- As of the date of this report Canada and the Global Community is experiencing unprecedented measures undertaken by various levels of government to curtail health related impacts of the Covid-19 Pandemic. The duration of this event is not known. While there is potential for impacts with respect to micro and macro-economic sectors, as well as upon various real estate markets, it is not possible to predict such impact at present, or the impact of current and future government countermeasures. Accordingly, this point-in-time valuation assumes the continuation of current market conditions, and that current longer-term market conditions remain unchanged. Given the market uncertainties of the Covid-19 pandemic, a force majeure event, we reserve the right to revise the value estimation set out in this report for a fee, with an update appraisal report under a separate appraisal engagement, incorporating market information available at that time. Values contained in this appraisal are based on market conditions as at the time of this report. This appraisal does not provide a prediction of future values. In the event of market instability and/or disruption, values may change rapidly and such potential future events have NOT been considered in this report. As this appraisal does not and cannot consider any changes to the property appraised or market conditions after the effective date, readers are cautioned in relying on the appraisal after the effective date noted herein.

3.0 Scope Of Work Undertaken

We have reviewed the identified market area to determine vacant sites and available facilities that meet the requirements identified. This review included:

- Review of prevailing MLS activity for the market area.
- Review of major commercial brokerage listings.
- Review / contact the City of Thunder Bay and Economic Development Department / Real Estate Department regarding available municipal properties.
- Contacted active commercial real estate professionals including brokers and appraisers.
- Contacted local developers active in industrial development.
- On-ground observations.

The analysis set out in this report relied upon written and verbal information obtained from a variety of sources considered reliable. Unless otherwise stated we did not verify client-supplied information, which we believed to be correct.

The work required conversations with Municipal departments as well interviews with owners, agents and developers in order to identify opportunities in the identified market area. All discussions were conducted with the strictest measures of confidentiality.

Excluded Item(s) of Review

The following technical investigations **were not completed**:

- An environmental review or study of the site alternatives, including a historical use analysis;
- Investigation into bearing qualities of the soils;
- Subsurface qualities of the soil; percolation or other soil qualities; or;
- An archaeological review.

We note that all referenced sites are assumed to be free of contamination unless otherwise noted.

4.0 Consulting Framework

4.1 Report Format

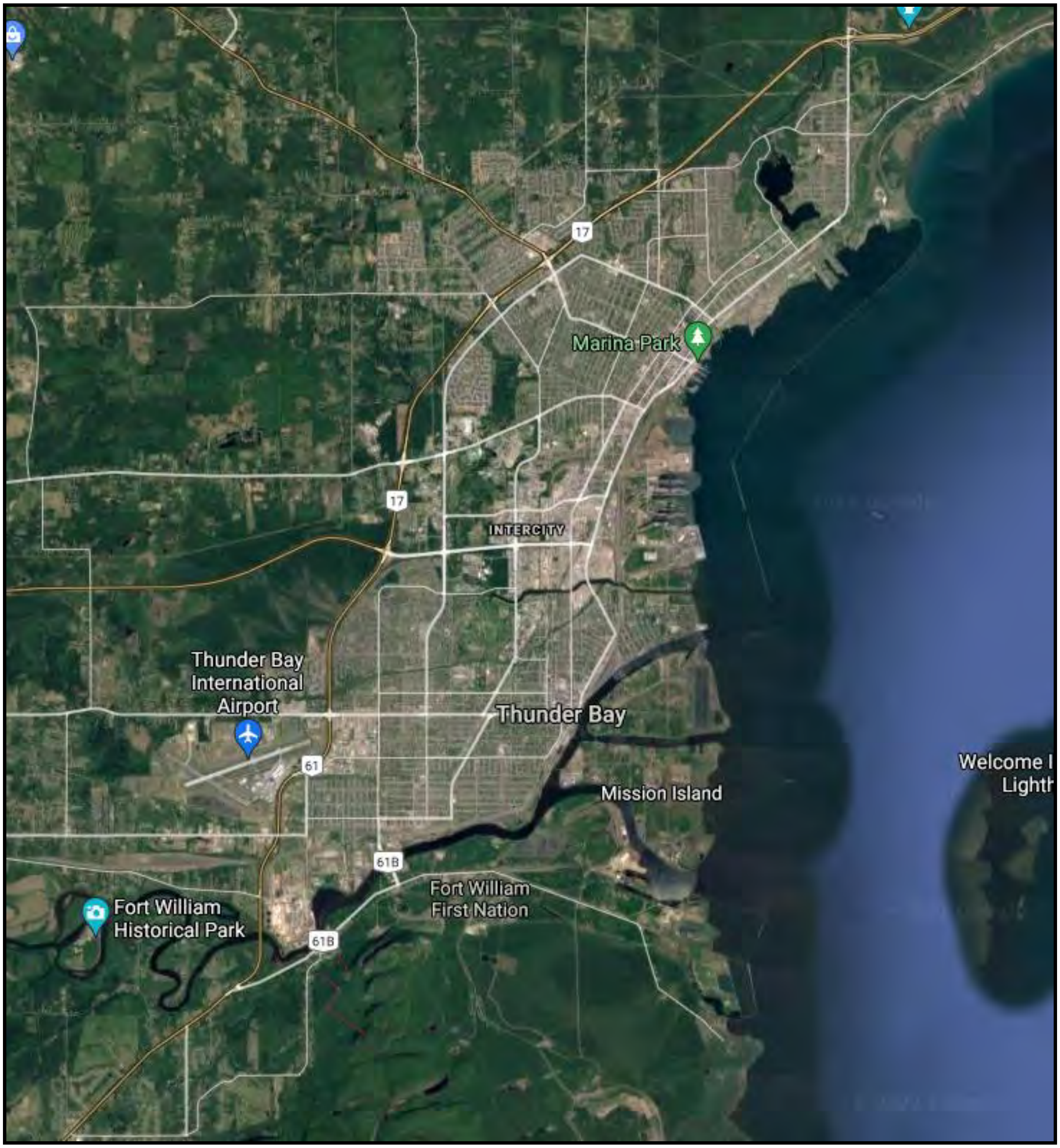
The Canadian Uniform Standards of Professional Appraisal Practice (CUSPAP) outlines the standard rules as it relates to the development and communication of a formal opinion of value and identifies the minimum content necessary to produce a credible report that is not misleading. The following reporting formats are available to the appraiser:

> ***Consulting*** - The development and communication of a real property consulting service must incorporate the minimum content necessary to produce a credible result that is not misleading.
>
> ***Current Value*** – refers to an effective date contemporaneous with the date of the report, at the time of inspection or at some other date within a reasonably short period from the date of inspection when market conditions have not or are not expected to have changed.

This current consulting report is provided with regard to the rules and regulations as outlined in CUSPAP.

5.0 Market Overview

5.1 Thunder Bay – General Overview



Positioned on the western shore of Lake Superior, the City of Thunder Bay is the central urban focus for Northwestern Ontario. It is the predominant urban centre for supply and service to a region that extends west for 375 miles (600 kilometres) to the Province of Manitoba; east for 250 miles (400 kilometres) to the District of Algoma, Ontario; and north for varied and considerable distances by road or air to several small communities and a number of remote access First Nation Reserves.

The economy of Thunder Bay was founded around being the most western Canadian terminus of the Great Lakes and St. Lawrence Seaway system, as well as the harvest and process of natural resources (timber and minerals) from a vast and surrounding hinterland region. This economy has been in transition since the late 1970's, with reduced use of waterway transportation and significant but variable changes in the nature of mining and forestry.

Over the past 40 years, changes in mining and forestry have had a more noticeable impact on the surrounding region of Northwestern Ontario. However, they have also caused changes in the nature of employment and business in Thunder Bay. Since the 1970's, the Thunder Bay economy has undergone a slow and occasionally painful transition from transportation and resource harvest and production, to regional service and supply.

Changes in Thunder Bay Population

Referencing information published by Statistics Canada, population changes for Thunder Bay and its surrounding Census Metropolitan Area are tracked as follows.

The Thunder Bay CMA extends east from the City Limits to include the adjoining rural Municipality of Shuniah, and west to include the rural Municipality of Oliver-Paipoonge and the rural Townships of O'Connor, Marks and Conmee. It extends north and northwest to include the rural Townships of Gorham and Ware, Jacques, Fowler and Dawson Road Lots. It extends south and southwest to include the rural Township of Gillies and the Municipality of Neebing.

Table 1

	Thunder Bay City	Thunder Bay CMA
Census Year 2001	109,016	121,986
Census Year 2006	109,140	122,907
Census Year 2011	108,359	121,596
Census Year 2016	107,909	121,621

The population of both the City of Thunder Bay and the Thunder Bay CMA have remained stable from 2001 to the most recent Census in 2016, with no population growth observed.

EXHIBIT 31 – POPULATION PROJECTIONS

Scenario	2016 (Census)	2019 (forecast)	2051 (forecast)	Change (2019-2051)
Base Case	107,810	108,935	124,241	15,306
Low Case	107,810	108,122	113,863	5,741
High Case	107,810	109,751	135,535	25,784
High+ Case	107,810	109,751	155,802	46,051

Figure 1: Employment Land Strategy 2020

5.2 ICI Land Supply & Demand

The City of Thunder Bay undertook an Employment Land Strategy Study in 2020. This study was completed by Cushman & Wakefield. The following represent excerpts from the Cushman & Wakefield an Employment Land Strategy Study 2020 dated September 30, 2020.

Land Demand

> *The employment by industry projection can be translated into a forecast of land needs by identifying the type of buildings that are required for each category of employment. The following highlights the conclusions of our land demand analysis.*
>
> *Industrial – Using a benchmark industrial employment density and a typical industrial building site coverage ratio, there is demand for approximately 30 gross hectares of industrial land through the 2051 forecast horizon.*
>
> *Office – Guided by recent office development formats in the city, employment in sectors that are associated with office-type space demand is anticipated to generate demand for 7 gross hectares for office uses by 2051.*
>
> *Institutional – In discussion with the city's largest institutional employers, there is no identified near or medium-term requirement for additional Institutional-designated lands. Large institutional sites/campuses all offer excess lands that can accommodate future development, and on-site intensification is their principal focus of growth.*
>
> *Retail-Commercial – The Consultant Team prepared two retail-commercial land demand scenarios that are guided by the same population forecast, but different assumptions about the amount of retail space demanded per capita. New retail-commercial uses will continue to emerge, and it is highly likely that some buildings within the existing inventory will become obsolete, and repurposed to a mixed-use or other form of redevelopment. It is recommended that the City plan for 25 gross hectares of retail-commercial land through 2051.*
>
> *Our analysis has identified a considerable supply of vacant, designated employment lands in the City of Thunder Bay. The demand assessment indicates that future employment land requirements can be accommodated on existing sites. Therefore, there is no identified need to consider the conversion of any non-employment lands for employment purposes.*

Land Supply

> *At an aggregate level, there is a vast supply of remaining undeveloped, designated industrial lands across Thunder Bay. This is particularly the case for Light Industrial-designated sites (520 vacant hectares) and Heavy Industrial-designated sites (over 200 vacant hectares), but the comment is also applicable to lands designated as Business Area (nearly 50 vacant hectares). Notably, this analysis does not even factor in existing occupied lands which may represent opportunities*

for intensification, or potentially redevelopment. A legacy of contamination of lands and buildings is a challenge in Thunder Bay on certain sites where there is a history of heavy industrial activity. Further, there are serviced employment lands at Thunder Bay International Airport that are suitable for industrial development – although these lands are not available for acquisition; these would be subject to a land lease arrangement.

While there are large concentrations of both Light Industrial and Heavy Industrial-designated vacant lands in areas on the city's periphery (including Mission and McKellar Islands), site visits by the Consultant Team have revealed a relative scarcity of vacant industrial lands in some of the more centrally-situated existing (built-up) employment areas. Of note, Innova Business Park represents a sizable inventory of remaining undeveloped lands that are centrally located, and more proximate to labour compared to other undeveloped planned industrial areas. Accordingly, the Light Industrial and Business Area lands located in Innova Business Park and to the north along Thunder Bay Expressway, Burwood Road, and Golf Links Road represent the best remaining undeveloped employment lands in the city, from a locational and market perspective.

Vacant Industrial Lands

EXHIBIT 2 – VACANT INDUSTRIAL LANDS

Industrial Category	# of Sites	Land Area (gross hectares)
Business Area	49	47
Heavy Industrial	142	202
Light Industrial	264	520
TOTAL	**455**	**770**

Figure 2: Employment Land Strategy 2020

As noted in the Land Study, there is a substantial supply of undeveloped industrial lands within Thunder Bay, however sites within that are serviced and within the core employment areas are more limited.

Building Permit Activity

3.5 Non-Residential Building Permit Activity

The Consultant Team reviewed building permits provided by City staff for the period from January, 2010 – December, 2019. Over this past decade, some 2,000 non-residential permits were issued across the City of Thunder Bay. We have classified the permits into four categories: Commercial, Institutional, Industrial, and Other (the "Other" category captures properties such as utilities, performing arts centres, transportation terminals, and other mixed uses that do not fall into the prior three categories). The following are notable observations from our analysis:

- New building permits accounted for nearly one-half of the total permit value ($440 million), but represented just 12% of total permits, by count of permit.
- Permits for additions and alterations to properties – reflecting reinvestment in the stock of non-residential buildings – totaled $488 million, and an 88% share of total activity, by count of permits.
- By count of permit, the Commercial category accounted for just over one-half of total permits (52%), followed by Institutional (21%), and Industrial (13%). Buildings in the Other category represented a 14% share of the total activity.
- Commercial permits totaled $400 million in value, split evenly between new and addition/alteration work.
- Institutional permits totaled $337 million, with addition/alteration work representing a slight majority of the total permit value.
- Industrial permits totaled $57 million value, with two-thirds of the value being associated with new construction activity.

EXHIBIT 13 – VALUE AND NUMBER OF PERMITS BY BUILDING TYPE

Building Type	New		Addition/Alteration		Total	
	Value ($Millions)	#	Value ($Millions)	#	Value ($Millions)	#
Commercial	$201	89	$199	961	$400	1,050
Institutional	$149	15	$188	396	$337	411
Industrial	$38	116	$19	136	$57	252
Other	$52	14	$82	274	$134	288
TOTAL	**$440**	**234**	**$488**	**1,767**	**$928**	**2,001**

Source: City of Thunder Bay and Cushman & Wakefield

Figure 3: Employment Land Strategy 2020

5.3 Area Summary

There is a substantial supply of undeveloped industrial lands within Thunder Bay, however sites within areas that are serviced and within the core central employment areas are more limited. Absorption of Industrial land has been relatively slow with only 14 new facilities constructed between 2010 and 2019. Although absorption has been limited, it has been reported by a number of developers and real estate brokers that there appears to be some increased demand for industrial sites in the community.

5.4 Development Incentives

There are a number of incentives available in the Thunder Bay area for new investment and employment expansion in the area. We have discussed the availability of development incentives with Piero Pucci, with the Community Economic Development Commission. Most incentives, be it local, provincial or federal, are related to new community investment or new employment. There are limited incentives for the relocation of facilities that do not reflect a new employer or major expansion of an existing employer. The reported potential incentives are:

- Enbridge Gas Incentive: Contact David Sertic
  Tel: 807-684-8896

The following is a program that applies to private corporations. We are uncertain if the structure of HONI would qualify for this incentive.

- Regional Opportunities Investment Tax Credit
  - The Regional Opportunities Investment Tax Credit is a 20% refundable corporate income tax credit for capital investments. The tax credit is available for expenditures in excess of $50,000 and has a cap of $500,000.
  - The Regional Opportunities Investment Tax Credit is a 20% refundable corporate income tax credit for capital investments. The tax credit is available for expenditures in excess of $50,000 and has a cap of $500,000.
  - https://budget.ontario.ca/2020/marchupdate/annex.html#section-3

Any specific incentives are discussed in the individual site write-ups if applicable.

6.0 Characteristics of the Market

6.1 National Economic Overview

The National Bank Monthly Economic Monitor (June 2021) provides the following:

- *The daily number of new cases of Covid-19 declared around the world has been declining markedly over the last month. In the developed economies, the drop can be attributed in large part to an acceleration of vaccine rollouts encouraging an outlook of fuller and more lasting reopening of economies. Elsewhere, improvement in public health is due rather to reinforcement of physical distancing rules, especially in India where in late April a flare-up of cases forced the reintroduction of strict lockdowns in some regions. Since access to vaccines is much more limited in emerging countries, herd immunity is unlikely before 2022. Developing countries will accordingly remain at greater risk of pandemic outbreaks in the coming months, a factor that could mean higher volatility of growth rates. We nevertheless continue to expect a solid rebound of the global economy in 2021 and are maintaining our forecast of 6.0% growth for the year. In fact, our confidence in a vigorous recovery has risen, since distribution of vaccines has greatly reduced economic uncertainty and downside risks for growth.*
- *The latest U.S. economic indicators confirm what has been our outlook for a few months now: a very strong revival stimulated by highly accommodative monetary and fiscal policies. Nonfarm payrolls grew 559,000 in May, less than the expected 675,000 but more than the months before, suggesting a slow but steady revival of the labour market in step with reopening of the economy. Also in May, headline 12-month CPA inflation was 5.0%, the highest in 13 years. For the CPI excluding food and energy the 12-month rise was 3.8%, the highest since June 1992. The three-month-annualized readings are still more impressive: headline inflation 8.4%, core inflation 8.3%. Up to now, the bulk of inflationary pressure has come in the goods-producing sector, but inflation could also take off in services if consumers decide, as we think they will, to spend more on activities unavailable in recent months (e.g. restaurant meals and travel). For the U.S. economy as a whole, we have left our forecast of 6.9% growth this year unchanged but have increased 2022 growth to 4.3% to reflect further government spending on infrastructure and social programs. In our projections, U.S. real GDP will be back to its potential by the third quarter of this year.*
- *Early in 2021, as the two largest provinces in Canada decreed shutdowns of non-essential businesses, public health conditions seemed to augur little good for the Canadian economy in Q1. And all the other G7 countries except the U.S. did have GDP declines during the quarter. In Canada, however, not only did the contraction that many had apprehended not materialize, but the quarter ended with very solid real growth of 5.6% annualized, a showing that put the Canadian economy in a leading position. In real terms its output came within 1.7% of its peak pre-pandemic quarter (Q4 2019) – second-best in the G7. In nominal terms the Q1 growth was even more spectacular taking nominal GDP to a best-in-G7 3.0% above its pre-recession peak. This month we are keeping our forecast of real growth in 2021 at 6.0%. after a pause in the recovery in Q2 due to public-health measures and to production backlogs in the auto industry due to microchip shortages, impressive growth can be expected to continue as vaccination picked up speed allowing the reopening of services that entail physical proximity. Our forecast for 2021 growth in nominal terms is now 12.6%, unseen in 40 years.*

Canada
Economic Forecast

(Annual % change)*	2018	2019	2020	2021	2022	2020 (Q4/Q4)	2021 (Q4/Q4)	2022 (Q4/Q4)
Gross domestic product (2012 $)	2.4	1.9	(5.3)	6.0	4.0	(3.1)	5.2	2.9
Consumption	2.5	1.6	(6.0)	5.0	6.2	(4.4)	5.3	5.1
Residential construction	(1.7)	(0.2)	4.1	17.9	(5.1)	14.5	2.7	(4.3)
Business investment	3.1	1.1	(13.6)	0.1	5.7	(13.9)	4.8	4.8
Government expenditures	3.2	1.7	0.4	4.8	1.7	2.4	2.9	1.5
Exports	3.7	1.3	(10.0)	5.9	5.0	(7.4)	5.2	4.7
Imports	3.4	0.4	(11.2)	7.9	5.3	(5.9)	4.8	5.1
Change in inventories (millions $)	15,486	18,766	(15,937)	4,134	13,617	(287)	16,000	13,160
Domestic demand	2.5	1.4	(4.3)	5.6	3.7	(2.0)	4.3	3.1
Real disposable income	1.5	2.2	9.5	(0.0)	(0.6)	7.4	(0.5)	1.1
Employment	1.6	2.2	(5.1)	4.4	2.8	(2.9)	3.2	2.0
Unemployment rate	5.9	5.7	9.6	7.7	6.3	8.8	6.6	6.1
Inflation	2.3	1.9	0.7	2.7	2.5	0.8	3.1	2.3
Before-tax profits	3.8	0.6	(4.0)	33.4	2.2	9.4	16.8	4.0
Current account (bil. $)	(52.2)	(47.4)	(40.1)	5.0	(38.0)	....	....	....

* or as noted

Financial Forecast**

	Current 6/11/21	Q2 2021	Q3 2021	Q4 2021	Q1 2022	2020	2021	2022
Overnight rate	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.75
3 month T-Bills	0.11	0.10	0.15	0.15	0.20	0.07	0.15	0.70
Treasury yield curve								
2-Year	0.32	0.30	0.35	0.45	0.65	0.20	0.45	1.20
5-Year	0.83	0.85	1.00	1.20	1.35	0.39	1.20	1.80
10-Year	1.37	1.40	1.55	1.75	1.90	0.68	1.75	2.20
30-Year	1.93	1.95	2.05	2.15	2.25	1.21	2.15	2.45
CAD per USD	1.21	1.19	1.17	1.20	1.21	1.27	1.20	1.23
Oil price (WTI), U.S.$	71	66	72	75	70	48	75	65

** end of period

Quarterly pattern

	Q1 2020 actual	Q2 2020 actual	Q3 2020 actual	Q4 2020 forecast	Q1 2021 forecast	Q2 2021 forecast	Q3 2021 forecast	Q4 2021 forecast
Real GDP growth (q/q % chg. saar)	(7.9)	(38.0)	41.7	9.3	5.6	1.2	7.4	6.6
CPI (y/y % chg.)	1.8	0.0	0.3	0.8	1.4	3.2	3.2	3.1
CPI ex. food and energy (y/y % chg.)	1.8	1.0	0.6	1.1	1.0	2.0	2.3	2.2
Unemployment rate (%)	6.4	13.1	10.1	8.8	8.4	8.2	7.4	6.6

National Bank Financial

Figure 4 Source: National Bank Monthly Economic Monitor June 2021

6.2 Real Estate Trends – MLS® Residential Average Price Trend (CREA):

There are no reliable statistics available for employment lands in the subject market place. To provide some context of the real estate market in Thunder Bay we reference the following statistics provided by CREA.

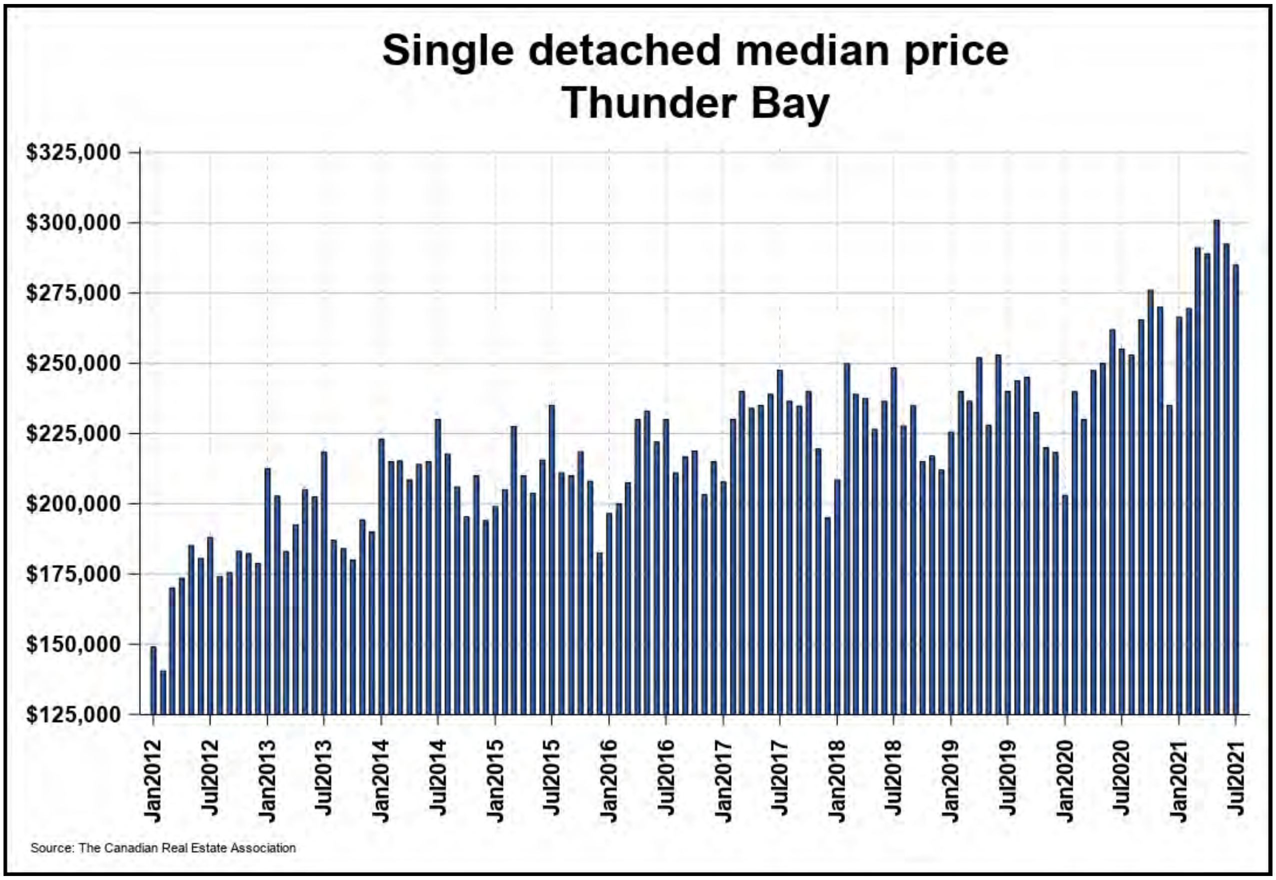


Figure 5: Source - CREA

On a year-to-date basis, single detached home sales totaled 651 units over the first seven months of the year. This was an increase of 79.8% from the same period in 2020.

The median sale price for single detached homes sold in July 2021 was $285,000, a gain of 11.7% from July 2020.

The more comprehensive year-to-date median price was $288,000, increasing by 16.9% from the first seven months of 2020.

Single detached properties spent less time on the market before selling in July 2021 than they had a year earlier. The median number of days on market for single detached home sales was 15 in July 2021, down from the 18 days recorded in July 2020.

The dollar value of all single detached home sales in July 2021 was $33.2 million, a sharp decrease of 10.5% from the same month in 2020.

7.0 Site Opportunities

Based on our extensive review there are few available development sites that meet the identified requirements. As such we have also included sites that may not meet all the requirements but are considered noteworthy.

The following Table outlines the location and site size of the potential site opportunities. Detail site writeups are provided following.

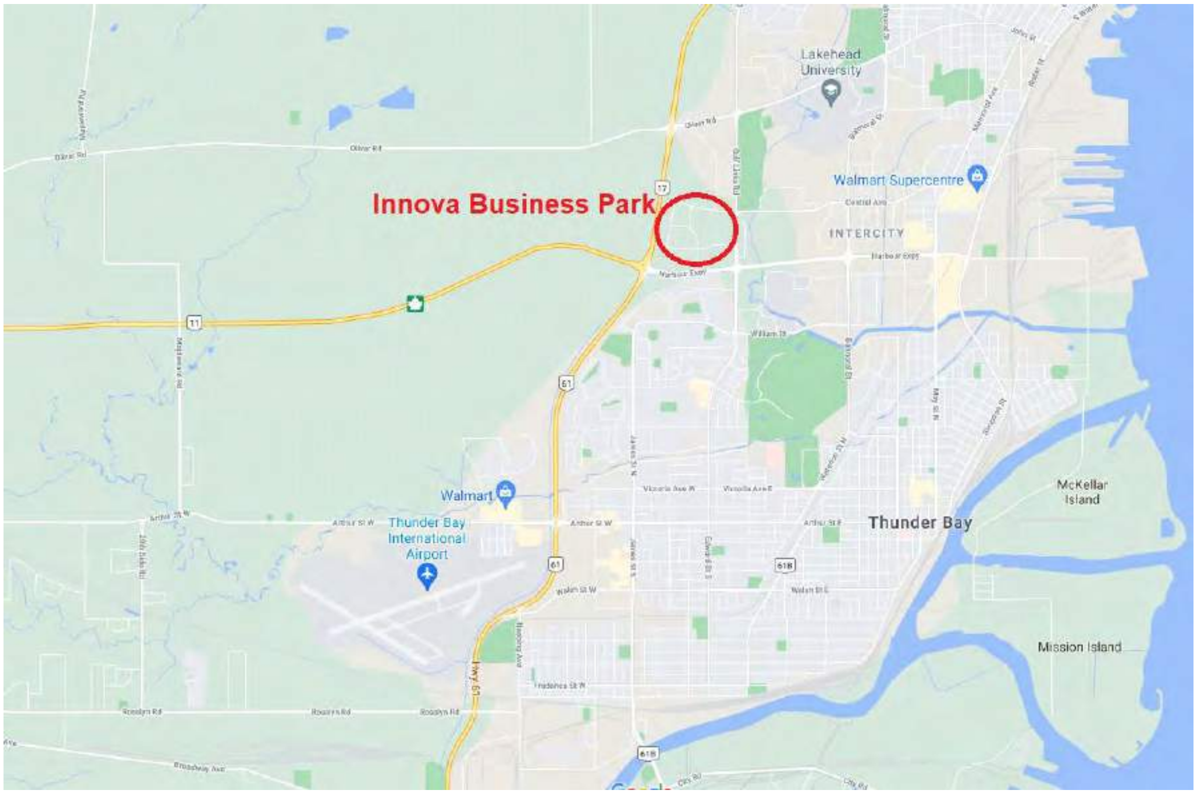
7.1 Site Opportunity Summary

Table 2

Site Summary Table			
#	**Location**	**Site Size**	**Comment**
Site Opportunities Meeting Essential Criteria			
1	Innova Industrial Park, Thunder Bay	Flexible Site Size	• Fully serviced employment land in municipal business park. • Appears to have been increased interest with a number of sites developing or with pending sales. • Only roughly 6 acres of medium industrial zoned lands (IN2) still available. Lots of Prestige Industrial available which the City has indicated would be likely suitable for the subject use although possibly requiring a zoning amendment. • May be also opportunity for a split zone site to be suitable. • Lands are generally flat but require significant muskeg removal and fill.
2	Thunder Bay Airport Industrial Park	Flexible Site Size	• Leased land only not available for purchase. • Fully serviced with no reported development constraints other than possibly height, which the client has reported is not a concern. • May be opportunity for direct airside access.
Other Site Opportunities			
3	1279 Rosslyn Road. Thunder Bay	7.5 acres Can be Severed	• Partial serviced site with no sanitary sewer. • Owner is not actively looking to sell but may consider if approached but would have to be the builder of the project. Would prefer to develop and leaseback. • Would be willing to sever into a smaller site.
4	Highway 130, Rosslyn	9.2 acres Can be Severed	• Rural services. • Would likely require a zoning amendment but the owner has reported zoning is highly flexible.
5	Cooper Road, Rosslyn	19.3 acres Can be Severed	• Rural services
6	965 Strathcona Rd	20 acres Can be Severed	• Fully serviced heavy industrial land. • Removed (18 km +/-) from airport.

7.2 *Site Opportunities – Detailed Write-Ups*

Site #1 - Innova Business Park, Thunder Bay



Nearest Intersection	Harbour Expressway & Premier Way
Municipality	City of Thunder Bay
Asking Price	$65,000 to $110,000 per acre **We note that these lands require significant excavation of muskeg and fill. We have discussed this item with a large industrial building with experience in the neighbourhood who has indicated that these costs can vary widely. Approximate costs were suggested to be in the range of $100K to $125K per acre.**
Listing Status	Actively listed directly from City of Thunder Bay. The following lotting map identifies the sites that remain available within the development.
Listing Contact	Joel DePeuter 1-807-625-2991 Joel.DePeuter@thunderbay.ca
Owner	City of Thunder Bay
PIN #	Multiple PIN's: Sites severed once sold.
Lot Area (acres)	Lots ranging in size from 0.79 acres to 5.79 acres with assembly potential
Services Available	Full Services including Municipal water, sanitary, hydro & gas.

COMMENTS	
Location	These lots are located within a more recently developed Innova Business Park located west of the Thunder Bay Expressway (Highway 11-17) between Harbour Expressway and Central Avenue. This area is approximately 4 kms from the Thunder Bay International Airport Overall, the area has developed gradually but has seen some increased uptake more recently.
Land Use	Official Plan: Light Industrial Zoning: Lots 6-20 - IN2 (Medium Industrial Zone) Lots 1-47 - IN6 (Prestige Industrial Zone) The Innova Business Park is zoned into two categories being medium and prestige industrial. Medium Industrial Zone (IN2): Allows for light and medium industrial uses including service, transport, outdoor storage and utility uses. Prestige Industrial Zone (IN6): Allows for a narrower range of uses limited to industrial centre, light industrial use, technical office, and research and development. The zone also allows for financial, drive service units, recreational, restaurant when used together with a permitted use. In addition to the two zoning designations, the lots facing westerly toward the Thunder Bay Expressway and the lots facing southerly toward the Harbour Expressway may be subject to MTO and LRCA approvals and permits. We have discussed the potential for the proposed subject use on the lands zoned Prestige Industrial with Joel DePeuter. Although not explicitly permitted, Mr. DePeuter has indicated that given the large portion of subject office, such a use may be supported on the IN6-Prestige Industrial lands. Ultimately this would require negotiations with the City and is not a certainty. The IN2-Medium Industrial zoning would support the subject use.
Site Description	The Business Park has not yet been severed into individual parcels creating flexibility with regard to site size and configuration. The city has provided a conceptual lotting map which can be found. The lands are generally level and mostly cleared or with scrub brush. These lands have substantial excavation and fill requirements due to muskeg. The extent of the required removal and fill is dependent on the specific location with some locations requiring more fill. The City of Thunder Bay has the depths of Muskeg however this is not publicly available and is only provided once approached by a potential applicant.

Other Criteria	Development Charges	None
	Development Incentives	None
	Distance to Airport	4 kms +/-
	Distance to Hotel / Food Services	1.5 kms +/-
	Development Constraints and Risks	Site works related to Muskeg removal. City has reported that they have testing data that can be shared at negotiation.
	Distance to Major Highway	Immediate proximity to Trans-Canada Highway and Thunder Bay Expressway.
	Tax Rates (2021)	Industrial Occupied - 4.289451% Industrial Excess Land - 4.289451% Vacant Land - 4.289451%

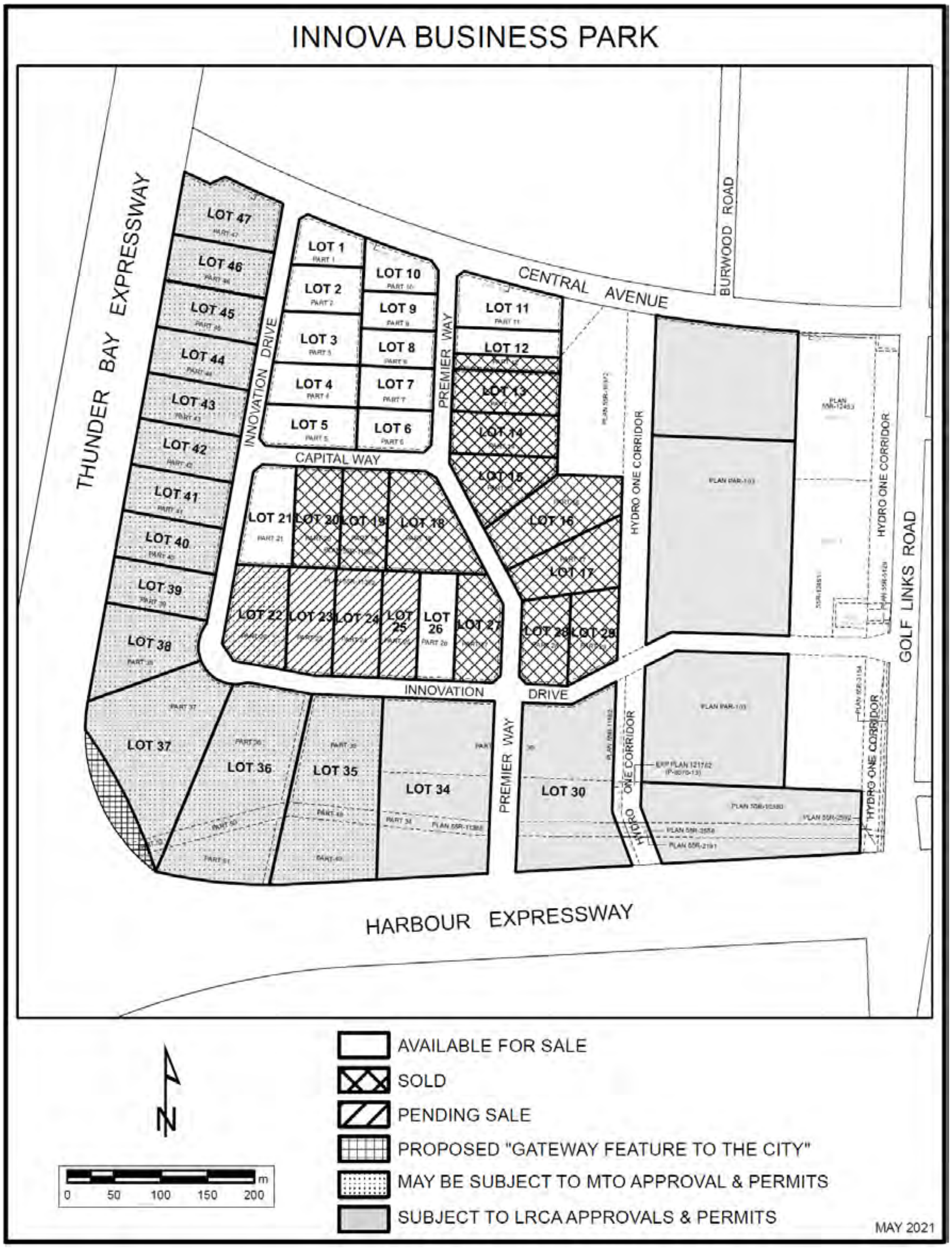
ADDITIONAL MAPS AND PHOTOS

Photos

ADDITIONAL MAPS AND PHOTOS

Conceptual Lotting Map

The following diagram outlines the available lots within the Innova Park. We note the large parcels to the east of the Hydro Corridor are also no longer available.



Site #2 - Derek Burney Drive, Thunder Bay
Thunder Bay International Airport Lands

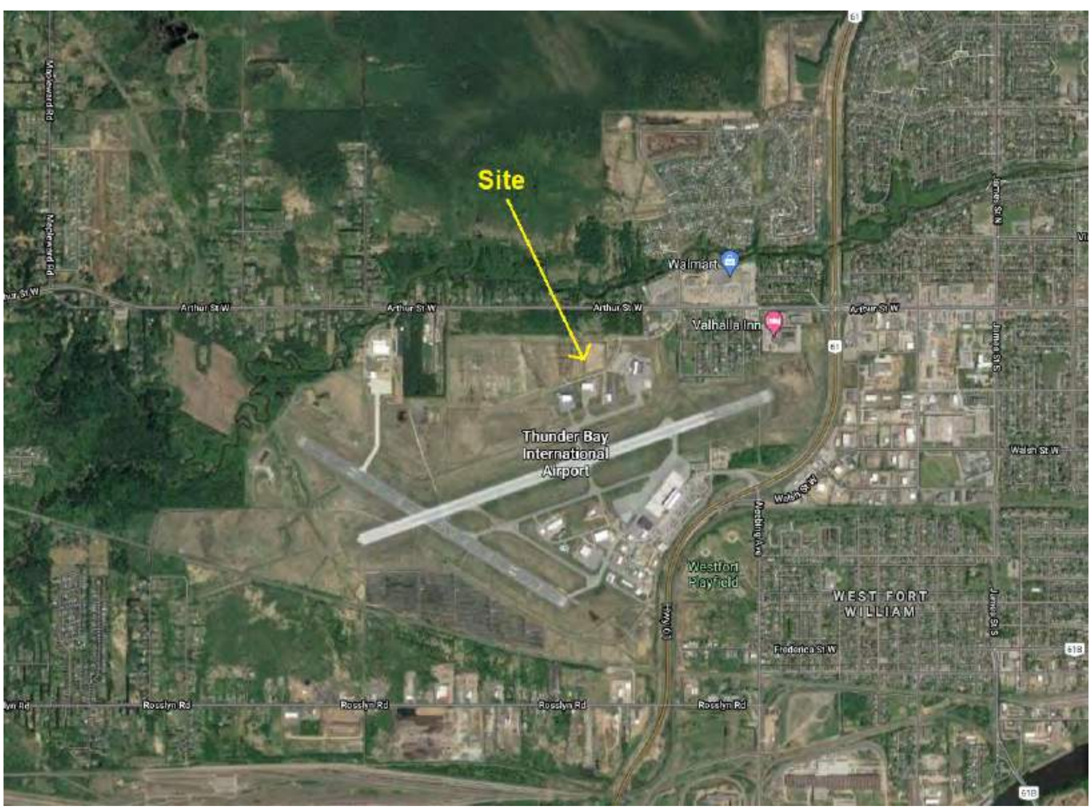
Nearest Intersection	Thunder Bay Expressway (Hwy 61) & Arthur Street West
Municipality	City of Thunder Bay
Listing Status	These lands are within the Thunder Bay International Airport. As such these lands are not available for purchase but rather for lease.
Asking Price	Lease Rates: In the Range of $0.40 to $0.45 per sq.ft.
Listing Contact	Ed Schmidtke 1-807-473-2602 schmide@tbairport.on.ca
Owner	Her Majesty The Queen In The Right Of Canada
PIN #	Part of: 620190087
Lot Area (acres)	The light industrial lands are a roughly 70 acre pocket with flexibility on site size and layout. The preferred location would be the easterly limit of the Light Industrial Lands as identified on the above diagram as to not leapfrog vacant land.
Services Available	Full Municipal Services: Sanitary, Water, Hydro & Gas.

COMMENTS		
Location	The property is located in the northern portion of the Thunder Bay International Airport site, at the southwest corner of the Thunder Bay Expressway (Hwy 61) & Arthur Street West. The light industrial lands more specifically front Derek Burney Drive which is accessed from Hawker Rd via Arthur Street West.	
Land Use	Official Plan: Airport Zoning: Airport (AP) Airport (AP): This zoning allows for a range of uses including "Aerospace Related Light Industrial Use" and "Aerospace Related Medium Industrial Use". Aerospace related uses describes a "use associated with or serving an airport, or directly related to the operation of aircraft". The subject use may not meet this criteria however we have discussed the zoning restrictions with the airport CEO Ed Schmidtke. Correspondence with Ed Schmidtke has indicated that Zoning is very flexible and fits with the described subject use. As such it appears that the subject use would be permitted on the Light Industrial Lands.	
Site Description	The property represents a large parcel of land that includes the airport. The light industrial lands are roughly 70 acres and can be readily divided into smaller leased parcels. The site is cleared and roughly flat.	
Other Criteria	Development Charges	None
	Development Incentives	None
	Distance to Airport	At Airport
	Distance to Hotel / Food Services	Immediate Neighbourhood
	Development Constraints and Risks	No noted development constraints other than likely height requirements for being in proximity to an airport.
	Distance to Major Highway	Access to Hwy 61 (Thunder Bay Expressway) is approximately 1 km to the east of the site.
	Tax Rates (2021)	Industrial Occupied - 4.289451% Industrial Excess Land - 4.289451% Vacant Land - 4.289451%

ADDITIONAL MAPS AND PHOTOS

Photos of Site (Google Street View)

Location Map



Site #3 - 1279 Rosslyn Road, Thunder Bay

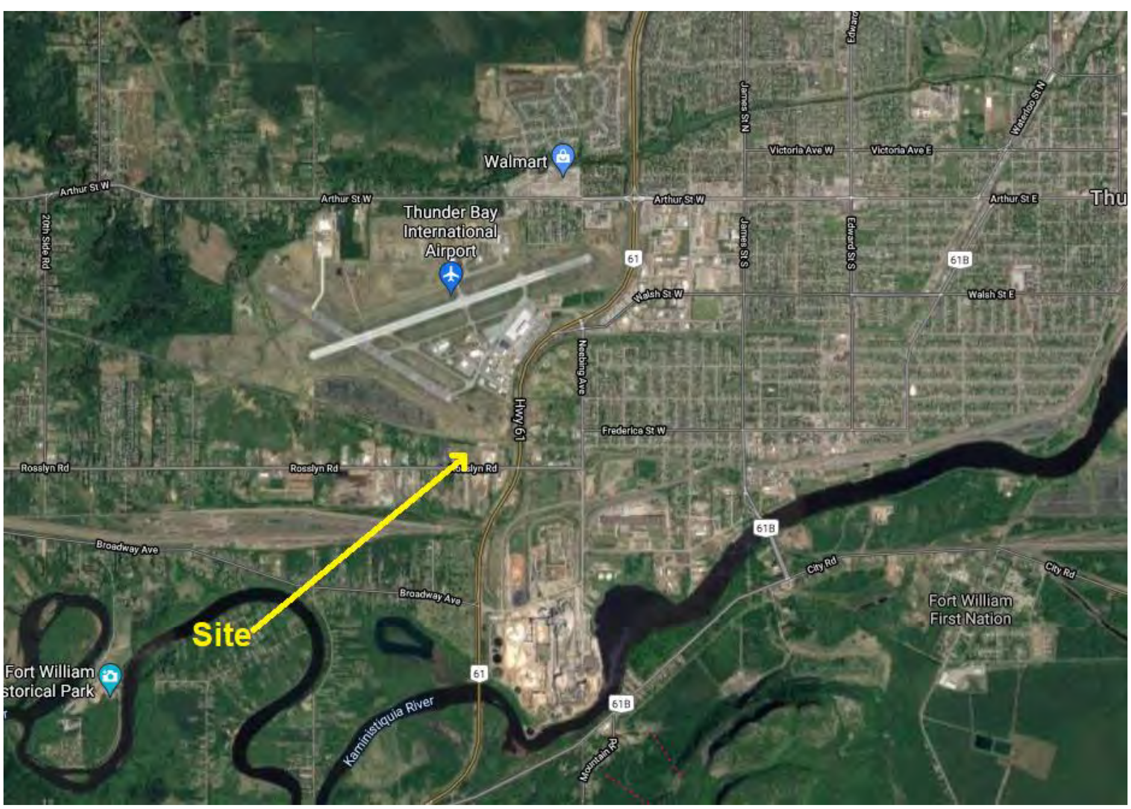
Nearest Intersection	Thunder Bay Expressway (Hwy 61) & Neebing Ave
Municipality	City of Thunder Bay
Listing Status	The property is not actively listed for the sale. The owner is a large commercial construction company who has indicated that they would prefer to develop and leaseback to the tenant but may consider a sale.
Asking Price	The owner has provided the following: *Without Prejudice: If I was interested in selling I would think for 5 acres I would be looking for $700,000 and a guarantee to build for the owner.*
Listing Contact	Ken Perrier 1-807-474-0930 perhol@perhol.com
Owner	1648841 Ontario Ltd. (Perhol Construction)
PIN #	Part of: 620180032; 620180031; 620180030; 620180024
Lot Area (acres)	The owner has indicated that they have a total of 7.5 acres +/- available that could be assembled / divided.
Services Available	Partial Services: Municipal water, hydro & gas. Requires private septic.

COMMENTS		
Location	This site is located on the north side of Roslyn Road, approximately 300 metres west of Hwy 61. The site is immediately south of the Thunder Bay International Airport. Access to Rosslyn Road is not directly available from Highway 61 but rather is accessed to the north via Neebing Road. Access to Highway 61 and the entrance to the airport is roughly 2 km.	
Land Use	Official Plan: Light Industrial Zoning: IN2-N (Medium Industrial Zone) Medium Industrial Zone (IN2): Allows for light and medium industrial uses including service, transport, outdoor storage and utility uses. The IN2-Medium Industrial zoning would support the subject use. “N” Suffix - Development on lands that have the suffix "N" may require noise studies and/or the implementation of noise mitigation measures prior to the issuance of any permit.	
Site Description	The property represents an approximately 7.5 acre assembled parcel of land that has an “L” shape. The site is cleared and generally level.	
Other Criteria	Development Charges	None
	Development Incentives	None
	Distance to Airport	2 kms +/-
	Distance to Hotel / Food Services	2 kms +/-
	Development Constraints and Risks	None Reported; Proximity to airport may have height requirements. May require sound study.
	Distance to Major Highway	Access to Hwy 61 (Thunder Bay Expressway) is approximately 2 km from the subject.
	Tax Rates (2021)	Industrial Occupied - 4.289451% Industrial Excess Land - 4.289451% Vacant Land - 4.289451%

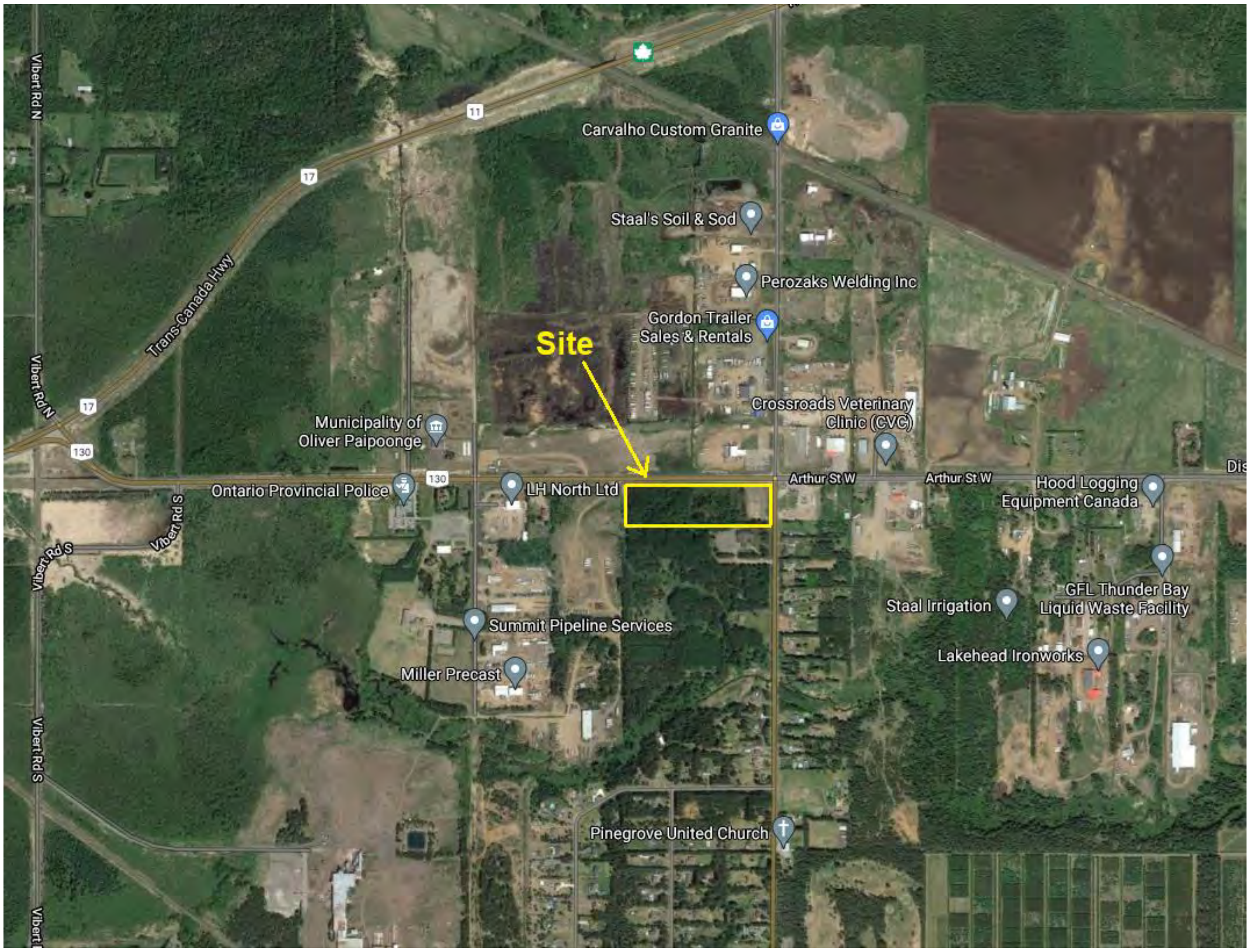
ADDITIONAL MAPS AND PHOTOS

Photos of Site (Google Street View)

Location Map



Site #4 - Highway 130 , Rosslyn



Nearest Intersection	Arthur Street / Highway 130 & Twin City Crossroad
Municipality	Municipality of Oliver Paipoonge
Listing Status	The property is not actively listed for the sale. The owner is a large commercial construction company who has indicated that they would be willing to sell a portion of the site.
Asking Price	$550,000 for 6 acres ($91,670 per acre +/-) – Note the outlined site is the entire 9.2 acre larger site.
Listing Contact	John Simperl 1-807-623-1855 john.simperl@brunocontracting.com
Owner	Bruno's Contracting (Thunder Bay) Limited
PIN #	622950301
Lot Area (acres)	The site has a total area of 9.2 acres +/-. The owner has reported that the site could be divided.
Services Available	Rural Services: Hydro & Gas; Would require private well & septic

COMMENTS		
Location	This site is located in the rural community of Rosslyn, approximately 9 km west of the Thunder Bay Airport. The site is situated at the southwest corner of Arthur Street W and Twin City Crossroad. The immediate neighbourhood is a small concentration of rural service commercial / industrial type uses. Many of the nearby uses are transportation and equipment related. Residential development is found farther to the south.	
Land Use	Official Plan: Commercial Zoning: GC- General Commercial Zone General Commercial Zone (GC): This zone allows for commercial and service commercial type uses. The zoning allows for office uses but does not provide for light or medium industrial uses. Yard storage appears to be only permitted in conjunction with permitted use such as equipment sales. It is unlikely that the proposed use would be permitted in this designation. The use would be likely defined as a Light Industrial use in the Zoning By-Law. A rezoning and OPA may be required to allow for the subject use. The property owner has indicated that the Township is very receptive and supportive of zoning and official plan amendments. The application fees for an OPA is $1,500 while a rezoning is $1,545 in addition to any planning and study costs.	
Site Description	The property represents a 9.2 acre rectangular shaped parcel that is reported to have severance potential. The site has roughly 1 acre of cleared area at the east limit that is improved with a gravel yard. The remainder of the site is forested. Overall, the site appears to be generally flat.	
Other Criteria	Development Charges	None
	Development Incentives	No development changes and relatively low tax rates.
	Distance to Airport	9 kms +/-
	Distance to Hotel / Food Services	9 kms +/-
	Development Constraints and Risks	None Reported
	Distance to Major Highway	Access to Hwy 17 (Trans Canada Hwy) is approximately 2 km west of the site.
	Tax Rates (2021)	Industrial – 2.972052% Industrial Vacant Land – 1.931834%

ADDITIONAL MAPS AND PHOTOS

Photos of Site (Google Street View)

Location Map

Site #5 - Cooper Road, Rosslyn

Nearest Intersection	Cooper Road & Highway 130
Municipality	Municipality of Oliver Paipoonge
Listing Status	The property is not actively listed for the sale. The owner is a large commercial construction company who has indicated that they would be willing to sell a portion of the site.
Asking Price	$550,000 for 6 acres ($91,670 per acre +/-) – Note the outlined site is the entire 19.3 acre larger site.
Listing Contact	John Simperl 1-807-623-1855 john.simperl@brunocontracting.com
Owner	North Star Holdings Incorporated
PIN #	622950686 & 622950591
Lot Area (acres)	The site has a total area of 19.3 acres +/-. The owner has reported that the site could be divided.
Services Available	Rural Services: Hydro & Gas; Would require private well & septic

COMMENTS

Location	This site is located in the rural community of Rosslyn, approximately 9 km west of the Thunder Bay Airport. The site is situated at the end of the developed portion of Cooper Road. The immediate neighbourhood is a small concentration of rural service commercial / industrial type uses. Many of the nearby uses are transportation and equipment related. Residential development is found farther to the south.	
Land Use	Official Plan: Industrial Zoning: Light Industrial (LI) Light Industrial (LI): This zone allows for a range of industrial uses including commercial garage, contractors yard, light industry and warehouse. Based on the permitted uses the subject use appears to be supported.	
Site Description	The property represents a 19.3 acre +/- rectangular shaped parcel that is reported to have severance potential. The site is mostly forested.	
Other Criteria	Development Charges	None
	Development Incentives	No development changes and relatively low tax rates.
	Distance to Airport	9 kms +/-
	Distance to Hotel / Food Services	9 kms +/-
	Development Constraints and Risks	None Reported
	Distance to Major Highway	Access to Hwy 17 (Trans Canada Hwy) is approximately 2 km west of the subject.
	Tax Rates (2021)	Industrial – 2.972052% Industrial Vacant Land – 1.931834%

ADDITIONAL MAPS AND PHOTOS

Photos of Site (Google Street View)

Location Map

Site #6 - 965 Strathcona Avenue, Thunder Bay

Nearest Intersection	Hodder Ave & Arundel Street
Municipality	City of Thunder Bay
Listing Status	Private Listing
Asking Price	$1,500,000 for 20 acres ($75,000 per acre) Would sever and sell smaller parcel
Listing Contact	Ian Bodnar 1-807-621-6358
Owner	ARA Holdings Inc.
PIN #	622620006
Lot Area (acres)	Larger Parcel – 20 acres; Roughly 14 acres to the west of Shipyard Rd. *Owner willing to divide into smaller parcels.
Services Available	Full Municipal Services: Sanitary, Water, Hydro & Gas.

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">The property is located near the northern limit of Thunder Bay, on the south side of Strathcona Avenue. This site is part of the former Abitibi Paper Mill property that encompassed a large waterfront industrial parcel including a mill, warehouse and office. The property is roughly 4 km from the Hodder Avenue intersection with Highway 17.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Heavy Industrial

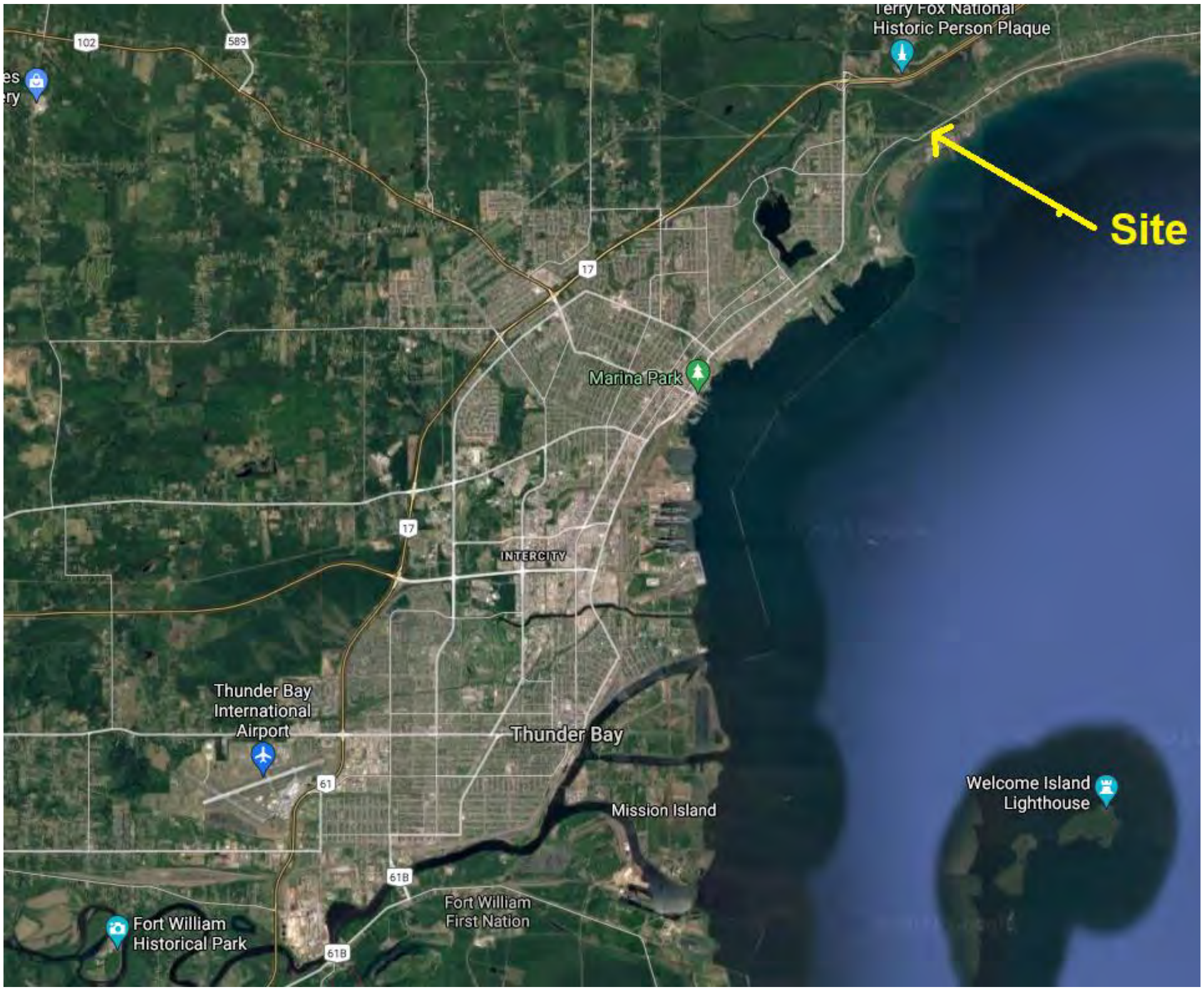
Zoning: Heavy Industrial Zone (IN3)

Heavy Industrial Zone (IN3) provides for a wide range of industrial uses including outdoor storage. It appears this zoning designation would support the subject use.</td></tr>
<tr><td>Site Description</td><td colspan="2">The property represents a 25-acre parcel of land that is somewhat narrow in shape (relative to the size), lying between Strathcona Ave on the north side and a railway on the south side. The site is bisected by Shipyard Rd, which appears to be a private road accessing the larger Abitibi Mill property. Roughly 14 acres are situated to the west of Shipyard Rd.

These lands are reported to be cleared sloping gradually from north to south.</td></tr>
<tr><td rowspan="7">Other Criteria</td><td>Development Charges</td><td>None</td></tr>
<tr><td>Development Incentives</td><td>None</td></tr>
<tr><td>Distance to Airport</td><td>18 kms +/-</td></tr>
<tr><td>Distance to Hotel / Food Services</td><td>7 to 18 kms +/-</td></tr>
<tr><td>Development Constraints and Risks</td><td>No noted development constraints.</td></tr>
<tr><td>Distance to Major Highway</td><td>Access to Hwy 17 is approximately 4 kms northwest of the site.</td></tr>
<tr><td>Tax Rates (2021)</td><td>Industrial Occupied - 4.289451%
Industrial Excess Land - 4.289451%
Vacant Land - 4.289451%</td></tr>
</table>

ADDITIONAL MAPS AND PHOTOS

Location Map



8.0 Building Opportunities

Based on our extensive review there are very few existing facilities that that meet the identified site requirements with a building that may be suitable with or without renovations. We have found two existing facilities that are being marketed that are considered to be a possible option.

Existing Facility #1 - 1820 Bailey Rd, Thunder Bay

Nearest Intersection	Arthur Street / Highway 130 & Twin City Crossroad
Municipality	City of Thunder Bay
Listing Status	Currently listed for lease at an asking rate of $6 per sq.ft.. Listing agent has noted that the owner would also be willing to sell. A portion of the building is currently leased.
Asking Price	$1,500,000 +/-
Listing Contact	Bob Phaff 1-807-473-7644 bob@bobpfaff.com
Owner	ARA Holdings Inc.
PIN #	620060068
Lot Area (acres)	6.75 acres
Building Size	25,000 sq.ft. – Mostly Warehouse Space
Services Available	Full Services: Municipal Water & Sanitary, Hydro & Gas

<table>
<tr><th colspan="3">COMMENTS</th></tr>
<tr><td>Location</td><td colspan="2">The property is located in the southern portion of Thunder Bay, within an older concentration of industrial development. Much of the industrial development is heavy uses. Some residential is present along Bailey Road which is a dead-end road.</td></tr>
<tr><td>Land Use</td><td colspan="2">Official Plan: Light Industrial

Zoning: Medium Industrial Zone (IN2)

Medium Industrial Zone (IN2): Allows for light and medium industrial uses including service, transport, outdoor storage and utility uses. The IN2 - Medium Industrial zoning would support the subject use.</td></tr>
<tr><td>Site Description</td><td colspan="2">The site represents 6.75 acre irregular shaped parcel. The site shape curves along a rail corridor on the north limit and wraps around the rear of residences on Baily Road. The site is cleared and appears to be generally level although we note we were unable to see the rear portion of the site.</td></tr>
<tr><td>Building Description</td><td colspan="2">The property is improved as a warehouse / service shop facility that was constructed in stages. Most of the building was constructed between 1964 to 1973 with an addition in 1991.

The building has a reported total size of 25,000 sq.ft. with minimal office space. The building is a mix of concrete block and steel construction. The main building is reported to have 16’ doors at each end, 20’ ceiling clearance, and an overhead crane.

Overall the building appears to be dated and in average condition at best.</td></tr>
<tr><td rowspan="7">Other Criteria</td><td>Development Charges</td><td>None</td></tr>
<tr><td>Development Incentives</td><td>None</td></tr>
<tr><td>Distance to Airport</td><td>3.5 kms +/-</td></tr>
<tr><td>Distance to Hotel / Food Services</td><td>4 kms +/-</td></tr>
<tr><td>Development Constraints and Risks</td><td>None Reported – We note this an old site and we are not aware of the past uses.</td></tr>
<tr><td>Distance to Major Highway</td><td>Access to Hwy 61 is approximately 3.5 kms west of the site.</td></tr>
<tr><td>Tax Rates (2021)</td><td>Industrial Occupied - 4.289451%
Industrial Excess Land - 4.289451%
Vacant Land - 4.289451%</td></tr>
</table>

ADDITIONAL MAPS AND PHOTOS

Photos of Building

Location Map

Existing Facility #2 - 965 Strathcona Road, Thunder Bay

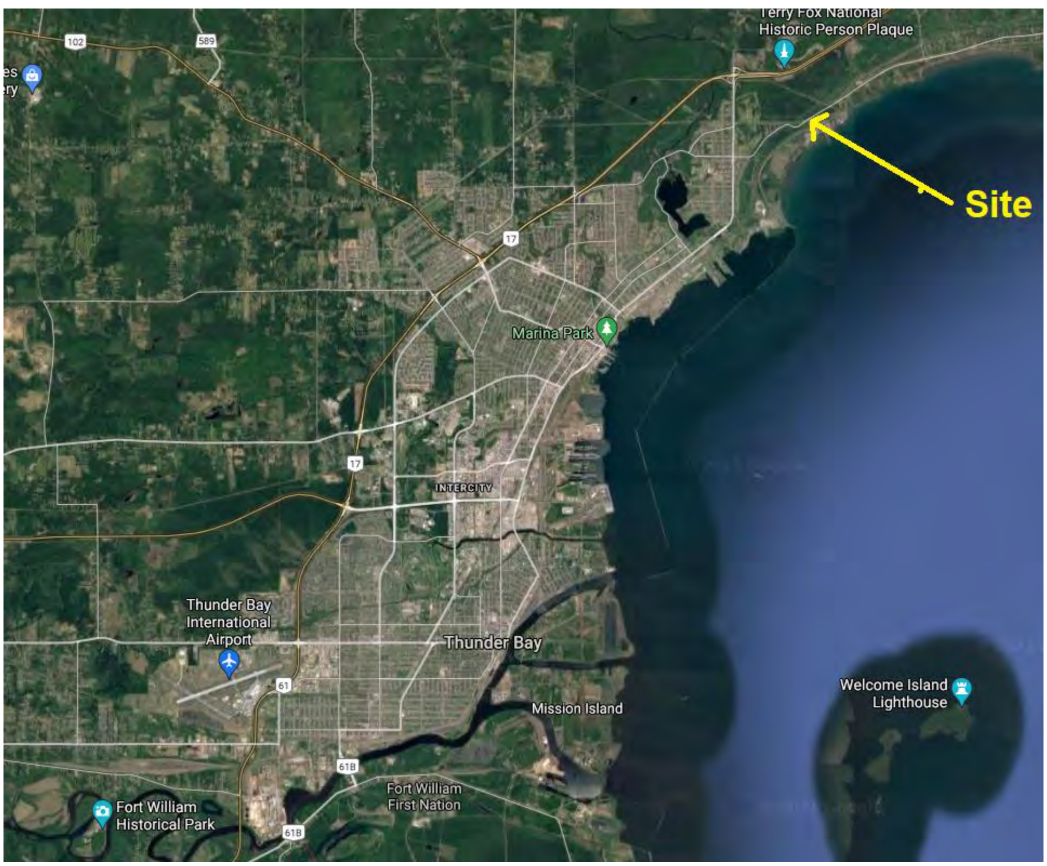
Nearest Intersection	Hodder Ave & Arundel Street
Municipality	City of Thunder Bay
Listing Status	Private Listing
Asking Price	$2,000,000 – Office Building + 6 acres +/-
Listing Contact	Ian Bodnar 1-807-621-6358
Owner	ARA Holdings Inc.
PIN #	Part of Larger Parcel with Multiple Pin #'s
Lot Area (acres)	6 acres +/-
Building Size	38,000 sq.ft. Including Basement – Two Storey Office Building
Services Available	Full Services: Municipal Water & Sanitary, Hydro & Gas

COMMENTS		
Location	The property is located near the northern limit of Thunder Bay, on the south side of Strathcona Avenue. This site is part of the former Abitibi Paper Mill property that encompassed a large waterfront industrial parcel including a mill, warehouse and office. The property is roughly 4 km from the Hodder Avenue intersection with Highway 17.	
Land Use	Official Plan: Heavy Industrial Zoning: Heavy Industrial Zone (IN3) Heavy Industrial Zone (IN3) provides for a wide range of industrial uses including outdoor storage. It appears this zoning designation would support the subject use.	
Site Description	The property represents a proposed roughly 6-acre parcel of land that is currently part of a larger site. The parcel is comprised of two parts lying on either side of a railway. The lands to the south of the railway are improved with an office building and a large paved parking lot reportedly suitable for roughly 200 vehicles and improved with electrical outlets. The lands to the north are vacant and appear to be partially forested.	
Building Description	The building is a two storey brick clad office building with a full basement. The building is marketed as being 38,000 sq.ft. which appears to include the basement space. The building is reported to be in good condition with some updates completed in recent history. A portion of the building is currently leased but can be provided vacant in the 45 days if needed. We note the larger property is also improved with a 50,000 sq.ft. warehouse developed along a container boat slip and with rail access. This building would require a larger site if included with the office portion.	
Other Criteria	Development Charges	None
	Development Incentives	None
	Distance to Airport	18 kms +/-
	Distance to Hotel / Food Services	7 to 18 kms +/-
	Development Constraints and Risks	No noted development constraints.
	Distance to Major Highway	Access to Hwy 17 is approximately 4 kms northwest of the site.
	Tax Rates (2021)	Industrial Occupied - 4.289451% Industrial Excess Land - 4.289451% Vacant Land - 4.289451%

ADDITIONAL MAPS AND PHOTOS

Photos of Building

Location Map



9.0 Beaverhall Industrial Area - Benchmark Land Value

As per the Terms of Reference we have been requested to provide a benchmark value range for industrial lands within the neighbourhood of the current "Remotes" facility at 680 Beaverhall Place. There are a number of vacant parcels within this neighbourhood within relatively close proximity to the existing facility.

The following table and diagram identify the primary parcels of vacant land within the subject neighbourhood.

Table 3

Vacant Neighbourhood Sites				
#	**Location**	**Site Size**	**PIN # / Owner**	**Last Sale Price / Date**
1	625 Beaverhall Place	1.69	620430049 / 1383793 Ontario Inc.	$300,000 / Sept 2014
2	645 Beaverhall Place	1.81	620430091 / Sparcon Construction Inc	$325,000 / Nov 2020
3	600 Beaverhall Place	1.56	620430043 / 2786341 Ontario Ltd.	$250,000 / Dec 2020
4	625 Mountdale Ave	1.45	620430089 / Mahon Electric Company Ltd	$167,000 / May 2016

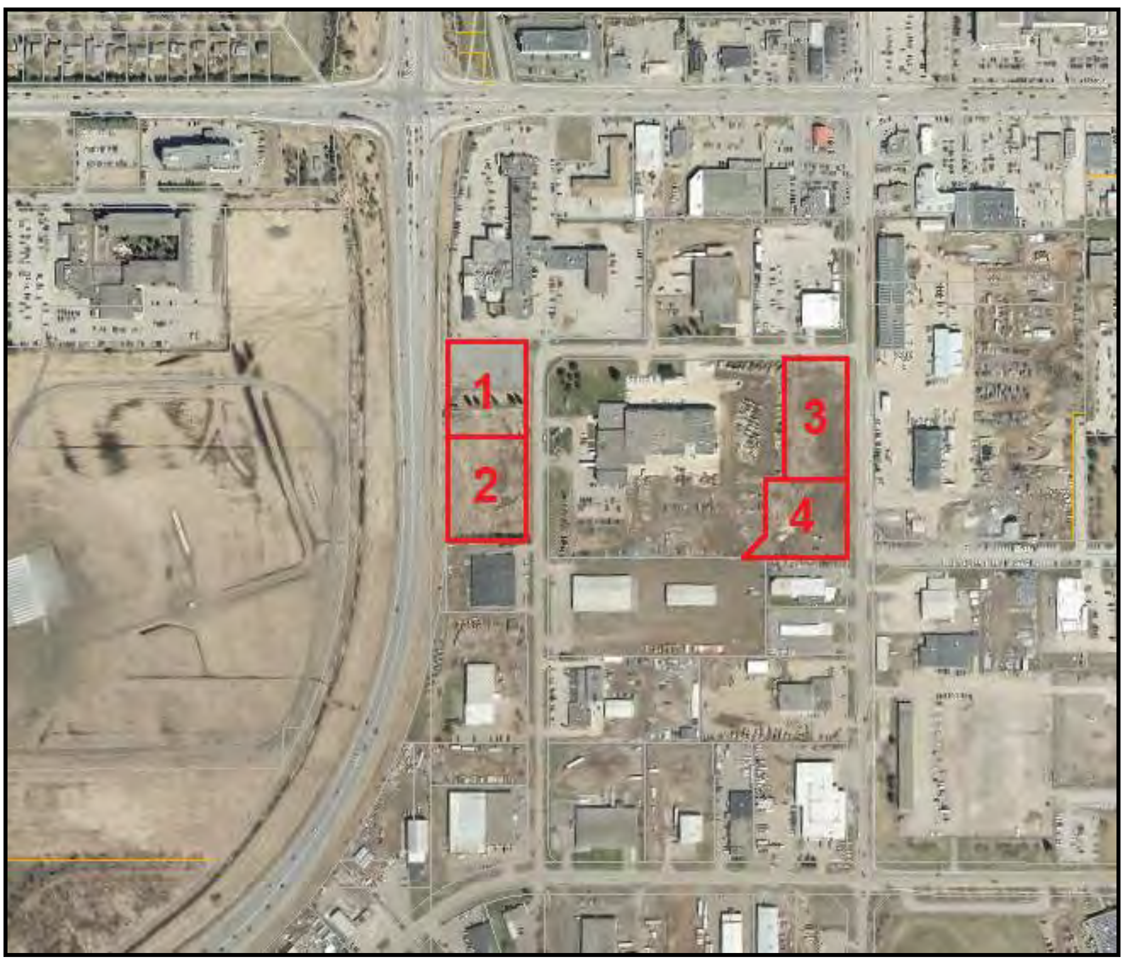


Figure 6

9.1 Direct Comparison Approach

The Direct Comparison Approach provides a basis for value through a process of adjustments for differences between comparable sales and the subject property. In this method, similar properties recently sold or offered for sale are analysed and comparisons are made based on a number of elements of comparison. These elements include real property rights conveyed, financial terms, condition of sale, expenditures made immediately after purchase, market conditions, location, physical characteristics, economic characteristics, use and zoning, and non-realty components of value. Elements that apply can be addressed quantitatively or qualitatively.

A unit of measurement is defined as a feature of a property that can be measured, for purposes of comparison, with the same common element or component of another property. For example, a selling price per “unit” could express a figure on a per square foot basis, per acre basis, per suite basis, or per room basis.

In this approach, similar properties recently sold or offered for sale are analysed and comparisons are made based on a number of elements of comparison. Elements of Comparison include:

- ***Real Property Rights Conveyed***
  Adjustments are made under this category for items such as existence of right of ways, easements, restrictive covenants which may impact the property.

- ***Financial Terms (financing)***
  Differences in financing arrangements that result in a higher or lower transaction price.

- ***Condition of Sale***
  Motivation of the buyer or seller that differs from the usual market conditions resulting in a sale that would not represent the market value of a property. This adjustment could be in the form of the vendor needing to make a quick sale due to a cash flow problem, a neighbouring property owner motivated to expand, or might emerge for a key property in an assembly.

- ***Expenditures Made Immediately After Purchase***
  Any expenses which a knowledgeable buyer would have considered and affected the price paid.

- ***Non-Realty Components***
  Any non-realty items such as personal property and business operations included in the sale price of the comparable.

These preceding adjustments are made before adjustment for market conditions (time).

- ***Market Conditions***
  Adjustments made for changes over time due to inflation, deflation or changes in investors' perceptions of the market. In the cases where a listing is considered it may be that a downward adjustment should be applied as typically properties sell for less than the asking price.

Following market adjustments, adjustments are made under the following main headings on a percentage or dollar basis as deemed appropriate.

- ***Location***

- ***Physical Characteristics***
  Physical differences such as site and building size, condition, accessory buildings etc.

- ***Economic Characteristics***
  Adjustments for attributes that directly affect its income. This element is usually applied to income-producing properties.

- ***Use and Zoning***
  Difference in current use potential of a comparable and the subject property.

Qualitative vs. Quantitative

Adjustments can be in the form of quantitative and/or qualitative adjustments. Quantitative adjustments may be applied as a percentage or dollar amount. Qualitative adjustments do not apply specific adjustments to sales but rather relies on comparisons. Qualitative techniques include trend analysis, relative comparison analysis and ranking analysis. In this instance we have completed a Quantitative analysis.

A survey of the local market area has been conducted and the following sales are concluded to best support value for the subject property. Detailed sales descriptions and sales location maps can be found in the Addenda of this report.

9.2 Direct Comparison Approach Table

Table 4

#	Location – Thunder Bay	Lot Size (acres)	Zoning	Sale Price	Sale Date / Registration Date	Time Adjusted Rate per Acre (rounded)	Adjustments Applied			Adjusted Value Per acre
	Neighbourhood Sales						**Location**	**Site Size / Scale**	**Topography**	
1	645 Beaverhall Place	1.81	Light Industrial	$325,000	11/26/20	$187,000				**$187,000**
2	600 Beaverhall Place	1.56	Medium Industrial	$250,000	12/04/20	$166,000				**$166,000**
3	685 Beaverhall Place	0.86	Light Industrial	$300,000	06/25/21	$350,000		↓		**$262,500**
4	625 Mountdale Ave	1.45	Medium Industrial	$167,000	5/04/16	$133,000				**$133,000**
5	625 Beaverhall Place	1.69	Highway Commercial	$300,000	9/09/14	$210,000				**$210,000**
	Other Sales									
6	295 Court St S	3.48	Medium Industrial	$1,150,000	7/30/21	$330,000	↓			**$231,000**
7	Dunlop St	1.09	Medium Industrial	$151,000	3/18/21	$141,000			↑	**$183,300**
8	224 Burwood Road	2.83	Prestige Industrial Hold	$399,900	1/15/20	$154,000	↑		↑	**$215,600**

↑ - Inferior to the Subject; ↓ - Superior to the Subject

9.3 Benchmark Land Value Analysis

The preceding Table outlines 8 sales of employment lands located in the City of Thunder Bay. The sales include 7 sites zoned for light or medium industrial uses and one neighbourhood sale zoned highway commercial. Five of the sales are from within the study area while 3 are within other industrial locations throughout Thunder Bay.

Majority of the sales are relatively recent being from 2020 or 2021. Two of the sales are dated but have been included due to the location within the immediate study area. Industrial /employment land values appear to have experienced some upward pressure over the past year or so while values had been more stagnant prior to this. We have applied a time adjustment of 1.5% per annum to the end of 2019 and a 6% per annum adjustment for 2020 and 2021. Once adjusted the sale provides a time adjusted sale price range of $133,000 to $350,000 per acre.

The wide time adjusted price range is primarily a result of differences in location, topography and site size / scale. Adjustments have been applied to account for these items.

Index 1 to Index 5 are all located in the immediate study area. All the sites are cleared and generally flat. Some zoning differences are present but all sites appear to provide for a range of employment uses. Index 5 is zoned for commercial, however, this is related to the former hotel use and it is likely that an alternate light industrial use would be suitable. One sale is much smaller at 0.86 acres and required and adjustment for scale. Once adjusted these sales indicate a range of $133,000 to $262,500 per acre. The lower end of the range represents a dated sale of a nearby site. Although adjusted for time the adjustment may not adequately account for changes over this extended period. The more recent sales (Index 1, 2 & 3) provide a narrower range of $166,000 per acre to $262,500 per acre.

Index 6 is the pending sale of a large parcel of employment land located on the fringe of the downtown core. This site has good exposure to a four-lane road and appears to possibly have some alternate development potential. Following an adjustment for superior exposure this sale indicates a rate of $231,000 per acre.

Index 7 is a small industrial parcel located centrally within Thunder Bay. The site is forested and required greater site works. Once adjusted this sale indicates a rate of $183,300 per acre.

Index 8 is the sale of a parcel of prestige industrial land located to the north of the subject study area. This site required clearing and greater site works. Once adjusted the sale indicates a rate of $215,600 per acre.

9.4 Direct Comparison Approach Conclusions

The selected comparable sales provide an adjusted range of $133,000 to $262,500 per acre. As noted the more recent neighbourhood sales provide a range of $166,000 to $262,500 per acre. The upper end of this range reflects the sale of a small site that was purchased by a nearby industrial tenant. It is our understanding that the purchaser was somewhat motivated and we would expect a benchmark rate for the subject location below this indication. The additional sales from outside the neighbourhood appear to support the indications provided by Index 1 to 3.

Considering the available sales data, it appears that industrial lands in the subject neighbourhood are trading in the general range of $180,000 to $240,000 per acre with upward pressure experienced in the past year. This appears to be stronger than observed in past years but is supported by the available market data. As such it is our opinion that a benchmark range closer to the upper end of the identified narrowed range is appropriate.

Therefore, we conclude a Benchmark Value for 1 to 2-acre industrial sites within the identified study area that are cleared and roughly graded of $210,000 to $240,000 per acre.

Industrial Land Benchmark Conclusion $210,000 to $240,000 per acre*

*Reflects 1 to 2-acre industrial sites within the identified study area that are cleared and roughly graded.

- Exposure Time

Exposure Time may be defined as: "The estimated length of time the property interest being appraised would have been offered on the market prior to the hypothetical consummation of a sale at market value on the effective date of the appraisal; a retrospective estimate based upon an analysis of past events assuming a competitive and open market." Exposure time is a function of price, time and use, not an isolated opinion of time alone. This is a retrospective estimate based upon an analysis of past events assuming a competitive and open market. It is always presumed to have preceded the effective date of the appraisal.

If competitively marketed, it is estimated that an exposure time of 3-12 months prior to the effective date of valuation would have been required to sell the subject property at the appraised market value.

9.5 Final Conclusions / Reconciliation:

- There are few available industrial sites in the desired subject site size range. The preceding identifies two options that appear to meet the criteria and a number of additional options that may not meet all the requirements but were considered note worthy.
- Available existing facilities are very limited in the required size range. We have identified two options but note that these do not appear to meet a number of requirements.
- We conclude a Benchmark Value for 1 to 2-acre industrial sites within the identified Beaverhall study area that are cleared and roughly graded of $210,000 to $240,000 per acre.

10.0 Summary Of Qualifications

Peter Spivey, B.Sc., AACI, P.App

Peter Spivey obtained his honours degree in biology with a minor in geography from the University of Guelph. Upon completion of his university degree, Peter Spivey entered the appraisal field and achieved his AACI (Accredited Appraiser Canadian Institute) designation in 2009.

RELATED WORK HISTORY

2006 – Present	Andrew, Thompson and Associates Ltd.

QUALIFICATIONS

AACI	Accredited Appraiser Canadian Institute This designates a fully accredited membership in the Institute and indicates a high level of competence in a wide range of real estate appraisal.
B.Sc.	Bachelor of Science • Honours Marine and Freshwater Biology Major (University of Guelph) • Geography Minor (University of Guelph)

CERTIFICATES AND COURSES

UBC - Real Estate Appraisal Course Stream (15 Courses)
Completion of the Eco Gift Seminar

OTHER ACHIEVEMENTS

Director, Ontario Expropriation Association.

VALUATION EXPERIENCE

Land	Residential Subdivision; Industrial Subdivisions; Rights of Way; Easements; Highway Widenings; Institutional Sites; Waterfront; Recreation Lands; Agricultural, Wood Lot, Escarpment Lands, etc.
Commercial	Downtown; Strip Plaza; Special Use; Freestanding Office Buildings; Converted Dwellings; Restaurants; Service Stations, etc.
Institutional	Airports; Federal; Provincial and Municipal Assets; School Sites; Utility Easements and Right of Ways; Utility Buildings; Transportation Facilities; Landfill Sites; Transmission Tower Sites; Well and Water Tower Sites, etc.
Agricultural	Hobby Farms; Land
Unique	Large Tracts; Large Institutional Buildings; Education Development Charges.
Consulting	Expropriation; Peer Review; Education Development Charges; Alternative – Valuations
Government Consulting	Road Widening and Easement Projects; Sale of Municipal or Surplus Land; Land Acquisition; Conservation Easements, Eco Gift Valuations, Environmental Acquisition's, etc.

11.0 Assumptions, Limiting Conditions, Disclaimers And Limitations Of Liabilities

The certification that appears in this report is subject to compliance with the Personal Information and Electronics Documents Act (PIPEDA), Canadian Uniform Standards of Professional Appraisal Practice ("CUSPAP") and the following conditions:

1. This report is prepared only for the client and authorized users specifically identified in this report and only for the specific use identified herein. No other person may rely on this report or any part of this report without first obtaining consent from the client and written authorization from the authors. Liability is expressly denied to any other person and, accordingly, no responsibility is accepted for any damage suffered by any other person as a result of decisions made or actions taken based on this report. Liability is expressly denied for any unauthorized user or for anyone who uses this report for any use not specifically identified in this report. Payment of the appraisal fee has no effect on liability. Reliance on this report without authorization or for an unauthorized use is unreasonable.

2. Because market conditions, including economic, social and political factors, may change rapidly and, on occasion, without warning, this report cannot be relied upon as of any date other than the effective date specified in this report unless specifically authorized by the author(s).

3. The author will not be responsible for matters of a legal nature that affect either the property being appraised or the title to it. The property is appraised on the basis of it being under responsible ownership. No registry office search has been performed and the author assumes that the title is good and marketable and free and clear of all encumbrances. Matters of a legal nature, including confirming who holds legal title to the appraised property or any portion of the appraised property, are outside the scope of work and expertise of the appraiser. Any information regarding the identity of a property's owner or identifying the property owned by the listed client and/or applicant provided by the appraiser is for informational purposes only and any reliance on such information is unreasonable. Any information provided by the appraiser does not constitute any title confirmation. Any information provided does not negate the need to retain a real estate lawyer, surveyor or other appropriate experts to verify matters of ownership and/or title.

4. Verification of compliance with governmental regulations, bylaws or statutes is outside the scope of work and expertise of the appraiser. Any information provided by the appraiser is for informational purposes only and any reliance is unreasonable. Any information provided by the appraiser does not negate the need to retain an appropriately qualified professional to determine government regulation compliance.

5. No survey of the property has been made. Any sketch in this report shows approximate dimensions and is included only to assist the reader of this report in visualizing the property. It is unreasonable to rely on this report as an alternative to a survey, and an accredited surveyor ought to be retained for such matters.

6. This report is completed on the basis that testimony or appearance in court concerning this report is not required unless specific arrangements to do so have been made beforehand. Such arrangements will include, but not necessarily be limited to: adequate time to review the report and related data, and the provision of appropriate compensation.

7. Unless otherwise stated in this report, the author has no knowledge of any hidden or unapparent conditions (including, but not limited to: its soils, physical structure, mechanical or other operating systems, foundation, etc.) of/on the subject property or of/on a neighbouring property that could affect the value of the subject property. It has been assumed that there are no such conditions. Any such conditions that were visibly apparent at the time of inspection or that became apparent during the normal research involved in completing the report have been noted in the report. This report should not be construed as an environmental audit or detailed property condition report, as such reporting is beyond the scope of this report and/or the qualifications of the author. The author makes no guarantees or warranties, express or implied, regarding the condition of the property, and will not be responsible for any such conditions that do exist or for any engineering or testing that might be required to discover whether such conditions exist. The bearing capacity of the soil is assumed to be adequate.

8. The author is not qualified to comment on detrimental environmental, chemical or biological conditions that may affect the market value of the property appraised, including but not limited to pollution or contamination of land, buildings, water, groundwater or air which may include but are not limited to moulds and mildews or the conditions that may give rise to either. Any such conditions that were visibly apparent at the time of inspection or that became apparent during the normal research involved in completing the report have been noted in the report. It is an assumption of this report that the property complies with all regulatory requirements concerning environmental, chemical and biological matters, and it is assumed that the property is free of any detrimental environmental, chemical legal and biological conditions that may affect the market value of the property appraised. If a party relying on this report requires information or an assessment of detrimental environmental, chemical or biological conditions that may impact the value conclusion herein, that party is advised to retain an expert qualified in such matters. The author expressly denies any legal liability related to the effect of detrimental environmental, chemical or biological matters on the market value of the property.

9. The analyses set out in this report relied on written and verbal information obtained from a variety of sources the author considered reliable. Unless otherwise stated herein, the author did not verify client-supplied information, which the author believed to be correct.

10. The term “inspection” refers to observation only as defined by CUSPAP and reporting of the general material finishing and conditions observed for the purposes of a standard appraisal inspection. The inspection scope of work includes the identification of marketable characteristics/amenities offered for comparison and valuation purposes only.

11. The opinions of value and other conclusions contained herein assume satisfactory completion of any work remaining to be completed in a good and workmanlike manner. Further inspection may be required to confirm completion of such work. The author has not confirmed that all mandatory building inspections have been completed to date, nor has the availability/issuance of an occupancy permit been confirmed. The author has not evaluated the quality of construction, workmanship or materials. It should be clearly understood that this visual inspection does not imply compliance with any building code requirements as this is beyond the professional expertise of the author.

12. The contents of this report are confidential and will not be disclosed by the author to any party except as provided for by the provisions of the CUSPAP and/or when properly entered into evidence of a duly qualified judicial or quasi-judicial body. The author acknowledges that the information collected herein is personal and confidential and shall not use or disclose the contents of this report except as provided for in the provisions of the CUSPAP and in accordance with the author’s privacy policy. The client agrees that in accepting this report, it shall maintain the confidentiality and privacy of any personal information contained herein and shall comply in all material respects with the contents of the author's privacy policy and in accordance with the PIPEDA.

13. The author has agreed to enter into the assignment as requested by the client named in this report for the use specified by the client, which is stated in this report. The client has agreed that the performance of this report and the format are appropriate for the intended use.

14. This report, its content and all attachments/addendums and their content are the property of the author. The client, authorized users and any appraisal facilitator are prohibited, strictly forbidden, and no permission is expressly or implicitly granted or deemed to be granted, to modify, alter, merge, publish (in whole or in part) screen scrape, database scrape, exploit, reproduce, decompile, reassemble or participate in any other activity intended to separate, collect, store, reorganize, scan, copy, manipulate electronically, digitally, manually or by any other means whatsoever this appraisal report, addendum, all attachments and the data contained within for any commercial, or other, use.

15. If transmitted electronically, this report will have been digitally signed and secured with personal passwords to lock the appraisal file. Due to the possibility of digital modification, only originally signed reports and those reports sent directly by the author can be reasonably relied upon.

16. This report form is the property of the Appraisal Institute of Canada (AIC) and for use only by AIC members in good standing. Use by any other person is a violation of AIC copyright.

17. Where the intended use of this report is for financing or mortgage lending or mortgage insurance, it is a condition of reliance on this report that the authorized user has or will conduct lending, underwriting and insurance underwriting and rigorous due diligence in accordance with the standards of a reasonable and prudent lender or insurer, including but not limited to ensuring the borrower's demonstrated willingness and capacity to service his/her debt obligations on a timely basis, and to conduct loan underwriting or insuring due diligence similar to the standards set out by the Office of the Superintendent of Financial Institutions (OSFI), even when not otherwise required by law. Liability is expressly denied to those that do not meet this condition. Any reliance on this report without satisfaction of this condition is unreasonable.

18. All copyright is reserved to the author and this report is considered confidential by the author and the client. Possession of this report, or a copy thereof, does not carry with it the right to reproduction or publication in any manner, in whole or in part, nor may it be disclosed, quoted from or referred to in any manner, in whole or in part, without prior written consent and approval of the author as to the purpose, form and content of any such disclosure, quotation or reference. Without limiting the generality of the foregoing, neither all nor any part of the contents of this report shall be disseminated or otherwise conveyed to the public in any manner whatsoever or through any media whatsoever or disclosed, quoted from or referred to in any report, financial statement, prospectus, or offering memorandum of the client, or in any documents filed with any governmental agency without the prior written consent and approval of the author as to the purpose, form and content of such dissemination, disclosure, quotation or reference. This is subject only to confidential review by the Appraisal Institute of Canada as provided in the Canadian Uniform Standards of Professional Appraisal Practice.

12.0 Certificate Of The Appraiser

I certify that, to the best of my knowledge and belief that:

1. The statements of fact contained in this report are true and correct;
2. The reported analyses, opinions and conclusions are limited only by the reported assumptions and limiting conditions and are my impartial and unbiased professional analyses, opinions and conclusions;
3. I have no past, present or prospective interest in the property that is the subject of this report and no personal and/or professional interest or conflict with respect to the parties involved with this assignment.
4. I have no bias with respect to the property that is the subject of this report or to the parties involved with this assignment;
5. My engagement in and compensation is not contingent upon developing or reporting predetermined results, the amount of value estimate, a conclusion favouring the client, or the occurrence of a subsequent event.
6. My analyses, opinions and conclusions were developed, and this report has been prepared, in conformity with the CUSPAP.
7. I have the knowledge and experience to complete this assignment competently, and where applicable this report is co-signed in compliance with CUSPAP;
8. Except as herein disclosed, no one has provided significant professional assistance to the person(s) signing this report;
9. As of the date of this report the undersigned has fulfilled the requirements of the AIC's Continuing Professional Development Program;
10. The undersigned is (are all) members in good standing of the Appraisal Institute of Canada.

Final Conclusions

- There are few available industrial sites in the desired subject site size range. The preceding identifies two options that appear to meet the criteria and a number of additional options that may not meet all the requirements but were considered note worthy.
- Available existing facilities are very limited in the required size range. We have identified two options but note that these do not appear to meet a number of requirements.
- We conclude a Benchmark Value for 1 to 2-acre industrial sites within the identified Beaverhall study area that are cleared and roughly graded of $210,000 to $240,000 per acre.

AIC Appraiser

DRAFT

Signature: ____________________
Name: Peter Spivey, B.Sc, AACI, P.App, 904444
Date of Report:
Personally, Inspected the Subject Property Yes
Date of Inspection: July 22, 2021
Source of digital signature security: Password Protected PDF Document

Note: For this appraisal to be valid, an original or a digital signature is required and the document is to be password protected from modification.

13.0 Addenda

13.1 Detailed Land Sales and Sales Location Maps

13.1 Land Sales Map and Detailed Write Ups

Figure 7 Source: Google Earth

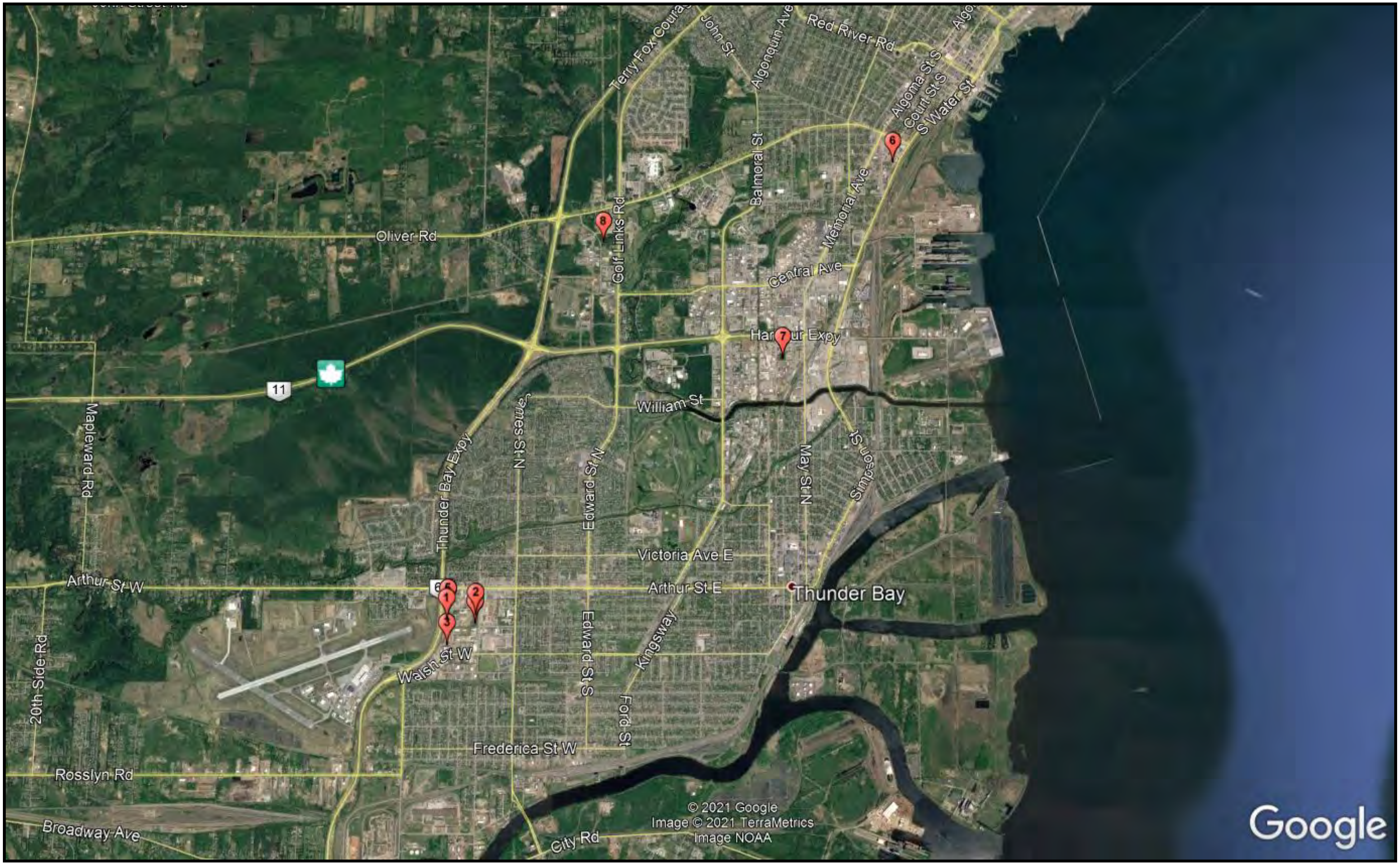


Figure 8 Source: Google Earth

COMPARABLE#: 1

Address:	645 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$325,000.00
Sale $/Unit:	$179,558 per acre
Sale Date:	Nov 26, 2020
Pin #	620430091
Vendor	948825 Ontario Inc.
Purchaser	Sparcon Construction Inc.
Roll Number	580404020102500

SITE INFORMATION

Lot Area:	1.81	acres	**Frontage:**	322	**Zoning**	IN2- Medium Industrial
Location:	Interior		**Services:**	Full	**OP:**	Industrial

Legal Description Lot 17 Plan W796,Neebing; City of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 2

Address:	600 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$250,000.00
Sale $/Unit:	$160,256 per acre
Sale Date:	Dec 04, 2020
Pin #	620430043
Vendor	Pepco Tbay Inc.
Purchaser	2786341 Ontario Ltd.
Roll Number	580404020103900

SITE INFORMATION

Lot Area:	1.56	acres	**Frontage:**	170	**Zoning**	ID2- Medium Industrial
Location:	Corner		**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 6 on Plan W796, Neebing Part 1, 55R10259; in the city of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is located at the intersection of Beaverhall Place and Mountdaye Avenue. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 3

Address:	685 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$300,000.00
Sale $/Unit:	$348,837 per acre
Sale Date:	Jun 25, 2021
Pin #	620430053
Vendor	Grant Equipment Corp.
Purchaser	539804 Ontario Inc.
Roll Number	580404020113105

SITE INFORMATION

Lot Area:	0.86	acres	**Frontage:**	127		**Zoning**	IN1- Light Industrial
Location:	Interior		**Services:**	Full		**OP:**	Industrial

Legal Description Part of Lot 20 on Plan W796, Neebing; Part Stanley Ave. on Plan QW796 Neebing, Closed by TBR413183, Part 1 and 2 on 55R7794; Subject to Right in TBR221127; in the city of Thunder Bay

Parcel of a small parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site was reportedly acquired by a nearby user to develop an industrial facility. This site was cleared and generally level and used as a storage yard at the time of the sale. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 4

Address:	625 Mountdale Ave.
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$167,000.00
Sale $/Unit:	$115,172 per acre
Sale Date:	May 04, 2016
Pin #	620430089
Vendor	Not Available
Purchaser	Mahon Electric Company Limitedà
Roll Number	580404020104000

SITE INFORMATION

Lot Area:	1.45	acres	**Frontage:**	244	**Zoning**	ID2- Medium Industrial
Location:	Interior		**Services:**	Full	**OP:**	Industrial

Legal Description Part of Lot 7 on Plan W796, Neebing, Parts 1 and 2 on Plan 55R14039, Subject to an Easement in Gross over Part 2 on Plan 55R14039 as in TY214023, in the city of Thunder Bay

Parcel of industrial land located in the Beaverhall Industrial Area (also known as the Airport Industrial Area), fronting the west side of Mountdale Avenue. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 5

Address:	625 Beaverhall Place
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$300,000.00
Sale $/Unit:	$177,515 per acre
Sale Date:	Sep 09, 2014
Pin #	620430049
Vendor	Royal Host GP Inc.
Purchaser	1383793 Ontario Inc.
Roll Number	580404020102600

SITE INFORMATION

Lot Area:	1.69 acres	**Frontage:**	300	**Zoning:**	C3- Highway Com.
Location:	Interior	**Services:**	Full	**OP:**	Commercial

Legal Description Part of Lot 16 on Plan W796 Neebing as in TBR341227 as ammended by TBR394415 except the Easement therein; Part of Block A on Plan 864 Neebing, Part 1 and 2 on 55R8957; Subject to TBR341227 and OFW54411; in the city of Thunder Bay

Parcel of commercial designated land located in a primarily industrial area known as the Beaverhall Industrial Area (also known as the Airport Industrial Area). This site is located adjoining an older motel and formerly formed part of the parking lot. Although designated commercial some opportunity may be present for conversion to an industrial type use. This site is cleared and generally level. The site enjoys close proximity to Thunder Bay International Airport and commercial amenities along Arthur Street.

COMPARABLE#: 6

Address: 295 Court Street S.
Municipality: Thunder Bay
Community: n/a
Sale Price: $1,150,000.00
Sale $/Unit: $330,460 per acre
Sale Date: Jul 30, 2021
Pin # 621260078 & 621260074
Vendor Arnone Transport Limited
Purchaser Not Yet Registered
Roll Number 580401003503600 & *

SITE INFORMATION

Lot Area: 3.48 acres **Frontage:** 409 **Zoning:** IN2- Medium Com.
Location: Interior **Services:** Full **OP:** Industrial

Legal Description Part Lot 1-4 Block 35on Plan 147 McIntyre; Part Lot 49-51, 54-55, 57 Plan 572 McIntyre Part 3 & 4, 55R10246; T/W TBR413511; Subject to PTA141390; Subject toTBR284105, TBR398827; in the city of Thunder Bay & **

Sale of a good quality parcel of employment land located centrally in Thunder Bay. This site had exposure to Water Street, a 4 lane arterial road and is on the fringe of the downtown core. The site is cleared and generally level and appears to have been utilized for trailer parking / storage.

MLS Sale Date: 06/25/2021

* 580401003500910
**Lots 73,75,77,79 & Part of Lots 54,56,58,80,81,82 & Part Inchiquin Street Closed by TBR163865, on Plan 572 AND Part Lots 2,3,4 & Part Lane Closed by TBR163865 & Part 0.30 Reserve Block 35 on Plan 147 Being Parts 1 & 5 55R12031 & Parts 7 & 8 55R10246 ; Thunder Bay ; Subject to Easements TBR438725,F128620,F132236 on Part 5 Plan 55R12031; in the city of Thunder Bay.

COMPARABLE#: 7

Address:	0 Dunlop Street
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$151,000.00
Sale $/Unit:	$138,532 per acre
Sale Date:	Mar 18, 2021
Pin #	620790552 & 620790507
Vendor	Not Available
Purchaser	1648822 Ontario Ltd.
Roll Number	580401003732800

SITE INFORMATION

Lot Area:	1.09 acres	**Frontage:**	200	**Zoning**	IN2- Medium Ind.
Location:	Interior	**Services:**	Full	**OP:**	Commercial

Legal Description Lots 132-136 on Plan M52 and Part Brandon Avenue, Plan M52 Closed by LT136601, Part 5 on 55R14780; in the city of Thunder Bay & Part Brandon Avenue on Plan M52 Closed by LT136601, Part 4 on 55R14780; in the city of Thunder Bay

Small parcel of industrial land located centrally within Thunder Bay. This site was treed and required clearing and some fill to allow for development.

COMPARABLE#: 8

Address:	224 Burwood Rd
Municipality:	Thunder Bay
Community:	n/a
Sale Price:	$399,900.00
Sale $/Unit:	$141,307 per acre
Sale Date:	Jan 15, 2020
Pin #	621170020
Vendor	Daniel Clara
Purchaser	Reliable Northern Developments Ltd.
Roll Number	580402010108000

SITE INFORMATION

Lot Area:	2.83	acres	**Frontage:**	248	**Zoning**	IN6- Prestige Ind.
Location:	Interior		**Services:**	Full in Area	**OP:**	Industrial

Legal Description Part of Lot 19 on Plan 760 McIntyre as in TBR215580; city of Thunder Bay

Parcel of industrial land located in the central portion of Thunder Bay, slightly east of Highway 17. The site was forested and required clearing and some grading / fill works. It is our understanding that full municipal services are in the area.

DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of Remotes' depreciation and amortization expense for the 2023 test year.

The depreciation expense for Remotes' submission for the 2023 revenue requirement was based on the methodology in an independent study conducted by Alliance Consulting Group (Alliance) for Hydro One Remote Communities in 2022.

Amortization expense pertains to costs the Board has allowed Remotes to defer for recognition at a future date. The Board has, in past decisions, approved the amount of the cost to be deferred for future recovery, the prescribed period or method of amortization and prescribed the time period over which the costs in each account should be amortized. Historical, bridge and test year amortization schedules are filed at Exhibit B, Tab 3, Schedule 1, Attachment 1.

1.1 APPROACH TO 2023 DEPRECIATION AND AMORTIZATION EXPENSE

The broad group depreciation methodology has been applied to the determination of 2023 depreciation expense. Consistent with the use of this proposed depreciation methodology by Hydro One Networks in the EB-2021-0110 proceeding that is currently before the Board, the broad group depreciation methodology was selected as the depreciation system to use for Hydro One Remotes, as it is more stable in the accrual rate computations and is used by the majority of North American utilities.[1]

The 2022 Depreciation Study completed for Remotes is filed at Exhibit B, Tab 3, Schedule 1, Attachment 2.

---

[1] See Exhibit B, Tab 3, Schedule 1, Attachment 2, p. 19 for further details

2.0 DEPRECIATION EXPENSE

The aforementioned Alliance methodology was used in determining the depreciation expense for the 2023 test year. Historical, bridge and test year depreciation expense schedule is filed at Exhibit B, Tab 3, Schedule 1, Attachment 1.

Table 1 - Depreciation Expense (*in thousands, $)*

Description	Board Approved	Historical				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Depreciation on Fixed Assets	2,942	2,925	2,867	2,834	3,058	3,075	3,244
Asset Removal Costs	634	394	511	361	343	347	327
Total	**3,576**	**3,319**	**3,378**	**3,195**	**3,401**	**3,422**	**3,571**

Fixed asset removal costs are charged to depreciation expense on an "as incurred" basis. Asset removals are flat year over year.

OEB Chapter 2, Appendix 2-BB – Service Life Comparison, is not applicable as Remotes does not have an expected change in asset life.

- OEB Chapter 2, Appendix 2-C – Depreciation and Amortization Expense for 2018 to 2023 are filed at part of the Chapter 2 Appendices (Exhibit A, Tab 2, Schedule 2, Attachment 1). The OEB model assumes a straight-line depreciation rate based on the life of the asset whereas Remotes uses the rates provided by their depreciation consultants, Alliance Consulting Group, based on Iowa Curves. The basis of Alliance's depreciable estimates and calculation process of the depreciation rates are further described in the 2022 Depreciation Study.[2]

[2] Exhibit B, Tab 3, Schedule 1, Attachment 2, p. 7 and 25

The adjustments from the 2022 Depreciation Study are reflected in the 2023 opening balances, resulting in minimal impact on useful asset life.

3.0 AMORTIZATION EXPENSE

Remotes recognizes a liability for estimated future expenditures required to remediate past environmental contamination associated with the assessment and remediation of contaminated lands, based on the net present value of these estimated future expenditures. Since these expenditures are expected to be recoverable in future rates, Remotes has recognized an equivalent amount as a regulatory asset. This balance is amortized as expenditures as they are incurred each year. The Board accepted this accounting treatment for Remotes in EB-2005-0020, EB-2008-0232, EB-2012-0137 and in EB-2017-0051. The treatment of these costs in this Application is consistent with the treatment in those proceedings. Remotes reviews its estimates of future environmental expenditures on an annual basis, as described in section 4.0 in this Exhibit below.

Table 2 shows historical bridge and test expenditures of Land Assessment Remediation (LAR). The LAR program involves assessment of historically contaminated lands, the implementation of remedial measures to treat, remove or otherwise manage the contamination found on and off-site and the implementation of on-site management controls to mitigate future off-site property impacts. Most of the contamination at Remotes' sites is associated with historic spills of diesel fuel.

Table 2 - Amortization Expense (*in thousands, $*)

Description	Board Approved	Historical				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Environmental Assets	1,032	942	3,851	870	1,435	2,606	1,833

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecasted expenditures are $852k higher primarily due to the remediation activities at the former diesel station in Cat Lake.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $449k higher primarily due to the remediation activities at the former diesel station Cat Lake.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecasted expenditures are $723k lower due to remediation activities in Webequie that are expected to occur in 2022.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $1,171k higher primarily due to expected remediation activities in Cat Lake and Webequie.

2018 ACTUALS VS 2018 OEB-APPROVED

- actuals expenditures were flat.

LAR projects are normally planned to coincide with major capital projects such as generation upgrades and extend over multiple years. As such, variances in year over year expense are typical, based on the timing of these discrete projects. As these projects are normally undertaken with the involvement of the local First Nations, negotiations are required, and project delays can occur. Differences between the planned and actual expenditures approved as part of Remotes' revenue requirement flow through the RRRP account, which is further discussed in Exhibit G, Tab 1, Schedule 1. The duration and cost have been impacted by lengthy negotiations on sites where multiple parties are involved and agreement of responsibility is required, funding constraints from other parties, weather restrictions, and the inability to put the work out for competitive bidding.

4.0 REGULATORY ASSETS AND LIABILITIES – LAR ENVIRONMENTAL PROVISION

Remotes reviews and updates its environmental liability pertaining to its LAR program on an annual basis to determine if any revisions are required to its environmental provisions and related regulatory assets. In 2021, the provision assumptions were reviewed for significant changes in work program plans (e.g. quantity of contaminated sites, extent of contamination, the year in which certain sites are anticipated to become grid connected), including costs and timing for monitoring and remediation, and changes in regulations. No major regulatory changes occurred in 2021. This review encompasses an assessment of the current state of applicable regulations as well as the sufficiency and accuracy of the current dollar cost estimate of performing the work and any revisions to the assumed pattern of expected future cash flows that give rise to the obligation's undiscounted value. Expected future cash flows are compiled by experienced Remotes staff and are reviewed by management at Networks and Remotes. Remotes' environmental liabilities consist of the undiscounted value of LAR. The same value is used to record the related environmental regulatory asset. The Board accepted this accounting treatment for Remotes in EB-2005-0020, EB-2008-0232, EB-2012-0137, and EB-2017-0051.

Remotes confirmed increases to the provision consistent with changes in the scope and timing of remediation work and the impact of the grid connection. The Remotes LAR provision was increased in 2021 compared to 2018 by $8.0 million, Table 3. The duration of the program was also extended a further 10 years (originally 2044) to the period ending 2054 to accommodate the additional work. The LAR provision is based on the most reliable information currently available and is mainly driven by revisions in the estimated scope of site remediation, the most recent information available for the costs of remediation, and an increase to annual monitoring costs due to remediation timing. The impact of grid connection is expected to occur in 2022-2024 for nine of the communities that Remotes currently serves, in which the generating stations will be used as backup until at least 2030 or the end of their useful lives. The generating stations at the road access sites will continue until the end of their useful lives. There are multiple moving parts with respect to grid connection of the communities and therefore the timing or use of current generation assets may be impacted by future decisions by ISC, provincial government, OEB, and the IESO. Monitoring costs are incurred until a site can be remediated, after which time they continue for an estimated three more years in order to ensure that the site is fully remediated. Full remediation cannot occur until the station and its components are removed from the site. At the end of 2021 the provision reflects what is reliably determinable based on facts known at that date and assumptions based on prior experience.

Table 3 - Environmental Liabilities (*in thousands, $*)

Description	Historical				Bridge	Test
	2018	2019	2020	2021	2022	2023
LAR Provision	35,145	34,095	43,378	43,191	42,237	40,354

The LAR Provision shown is an offsetting regulatory Asset and Liability. Future amortization expenses as described in Section 3.0 of this exhibit will be required in future periods to fully remediate all impacted sites.

DEPRECIATION AND AMORTIZATION EXPENSES

This exhibit has been filed separately in MS Excel format.

HYDRO ONE REMOTE COMMUNITIES

ELECTRIC UTILITY PLANT

DEPRECIATION RATE STUDY

BU 650

AT DECEMBER 31, 2021

JULY 2022

http://www.utilityalliance.com

HYDRO ONE REMOTE COMMUNITIES.
ELECTRIC UTILITY PLANT
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY
BU 650

AT DECEMBER 31, 2021

Hydro One Remote Communities Inc. (“Hydro One Remote” or the “Company”) engaged Alliance Consulting Group (“Alliance”) to conduct a depreciation study of the Company’s electric utility plant depreciable assets as of December 31, 2021.

This study proposes depreciation accrual rates based on year-end 2021 data that will be applied to plant balances. Based on 2021 year-end values, this study would result in an overall increase of $11 thousand in annual depreciation expenses for all accounts when using the proposed depreciation rates as compared to the existing annual depreciation accrual. A summary comparison of annual accrual by utility function is shown below.

BU 650 Remote Communities

Function	Plant at 12/31/2021	Existing Accrual	Proposed Accrual	Difference
Generation	47,138,163	2,327,615	2,301,990	(25,625)
Distribution	11,302,261	282,187	289,831	7.643
General Depreciated	13,105,978	357,506	386,595	29,089
Total	71,546,401	2,967,309	2,978,416	11,108

Appendix A shows the computation of depreciation rates based on 2021 year-end investment, and Appendix B shows a detailed comparison of the approved versus proposed depreciation rates and annual accruals by account for each utility function. Appendix C shows the existing and proposed parameters for Hydro One Remote. Appendix D shows a comparison of the book reserve with the reallocated reserve. Appendix E shows the projection life for each account. Appendix F details the qualifications of Alliance Consulting Group to perform this study.

HYDRO ONE REMOTE COMMUNITIES

ELECTRIC UTILITY PLANT

DEPRECIATION RATE STUDY

BU 650

AT DECEMBER 31, 2021

Table of Contents

PURPOSE

This study provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Hydro One Remote for its electric operations. The account-based depreciation rates were designed to recover the total remaining undepreciated investment over the remaining life of Hydro One Remote's property on a straight-line basis. Land and other non-depreciable property were excluded from this study.

Hydro One Remote is a subsidiary of Hydro One Inc. The Company generates electricity using diesel generators and distributes electricity to remote communities in Ontario's Far North. Most of those communities are off-grid and therefore not connected to the larger grid. The majority of these communities are First Nations. Hydro One Remote's customers experience the lowest electricity rates in Ontario. A figure showing the service territory for Hydro One Remote is shown in Appendix G.

STUDY RESULTS

Overall depreciation rates for all of Hydro One Remote’s depreciable property are shown in Appendix A. These rates translate into an annual depreciation accrual of $2.97 million based on Hydro One Remote's depreciable investment at December 31, 2021. The annual equivalent depreciation expense calculated by the same method using the approved rates was $2.96 million, resulting in a $11 thousand increase in annual depreciation expense. Appendix A presents the calculation of the annual depreciation rates and resulting accrual. Appendix B presents a comparison of approved versus proposed rates and annual accruals by account. Appendix C presents a summary of life and mortality curve parameters by account. Appendix D presents a summary of book depreciation reserve as compared to the reallocated depreciation reserve for each business unit. Appendix E presents a summary of estimated component life for each plant account within Hydro One Remote. Appendix F provides information on the background and qualifications of Alliance Consulting Group. Appendix G shows a map of Hydro One Remote’s service territory.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

Basis of Depreciation Estimates

For all depreciable accounts, the straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group.

The advantage of the broad group system is that all assets within an account are considered to be one group. Broad group depreciation is widely used and produces stable depreciation rates from year to year because of its averaging effects. The broad group procedure “requires the least accounting records of annual additions and balances."[1] There are other depreciation systems that could be considered, such as vintage group depreciation or equal life group. The Company's prior depreciation studies used straight line, vintage group, remaining life as the depreciation system. Vintage group depreciation assumes that each vintage is a separate group, requiring that each vintage be analyzed separately to determine its average life. All vintages are then composited to develop the average service life of the account. Given the stable results produced by broad group and its wider use across the utility industry, Alliance recommends changing the procedure to be more consistent with other utilities across North America. The computations of the annual functional depreciation rates are shown in Appendix A.

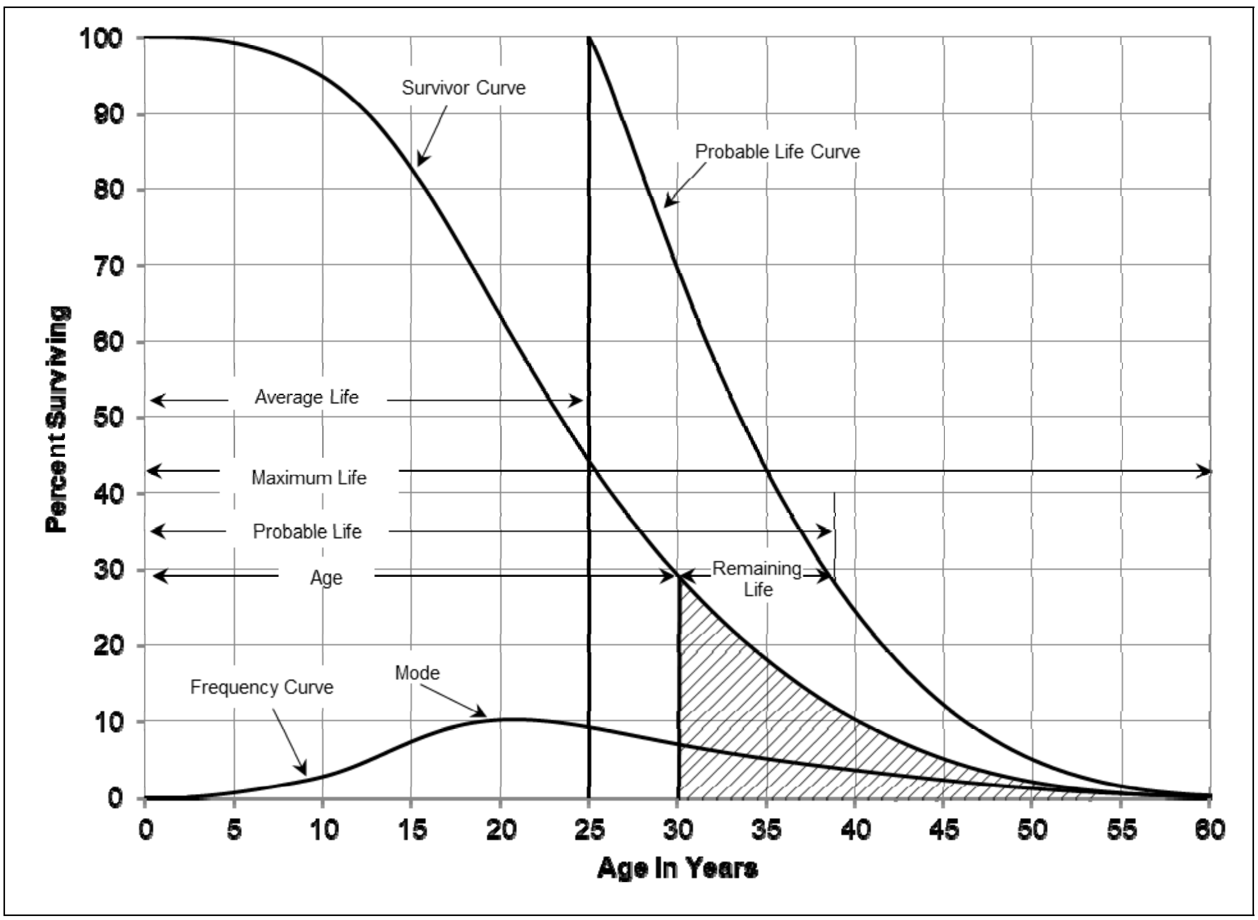
Actuarial analysis was used with each account within a function where sufficient data was available, and professional judgment was used to some degree on all accounts.

[1] Public Utility Depreciation Practices, National Association of Regulatory Utility Commissioners, 1996, p. 62.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The chart below shows a typical generalized survivor curve as well as some of the life characteristics that can be derived from the survivor curve.

GENERALIZED SURVIVOR CURVE

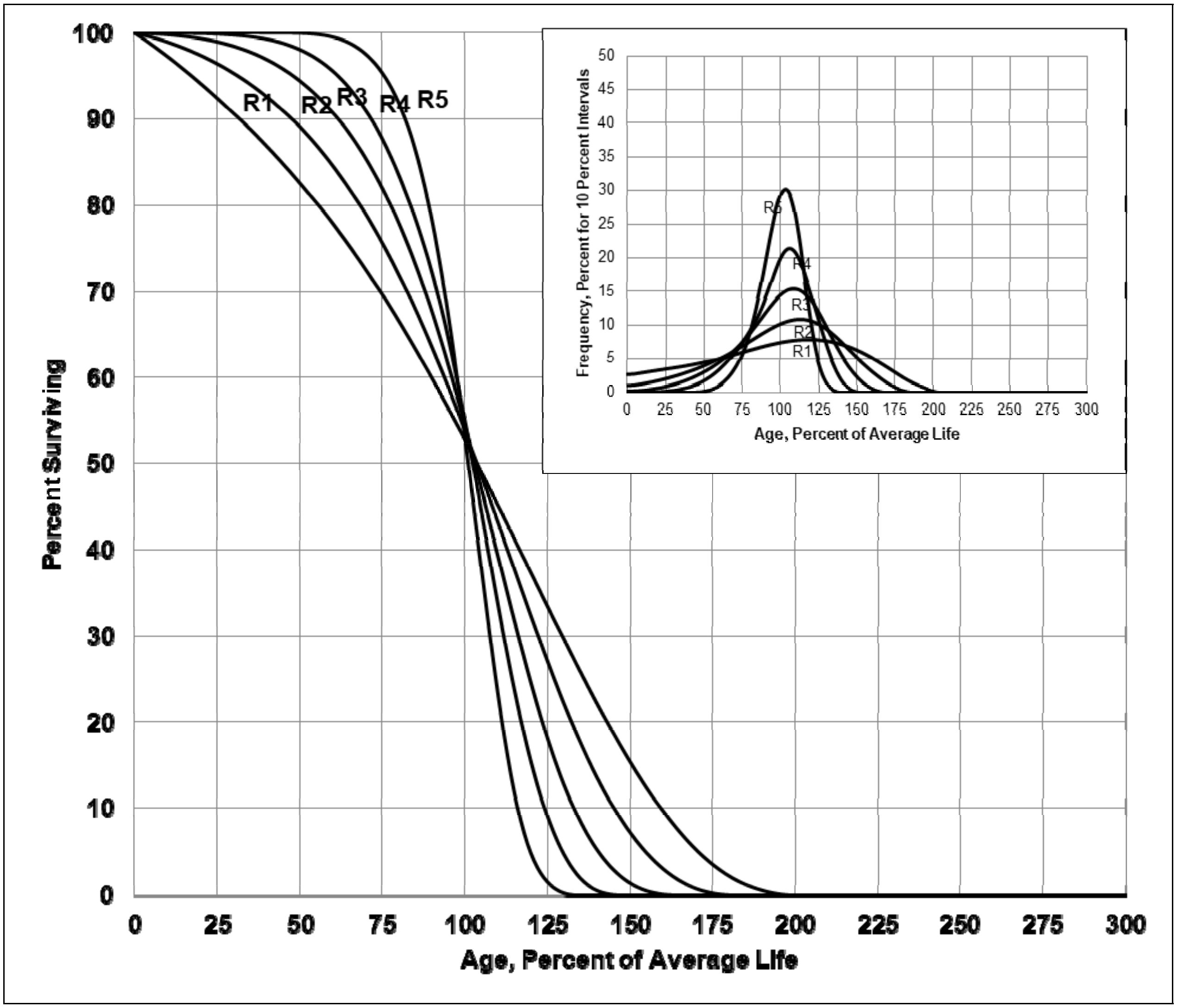


9

The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property.

There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of “R” moded curves is shown below.

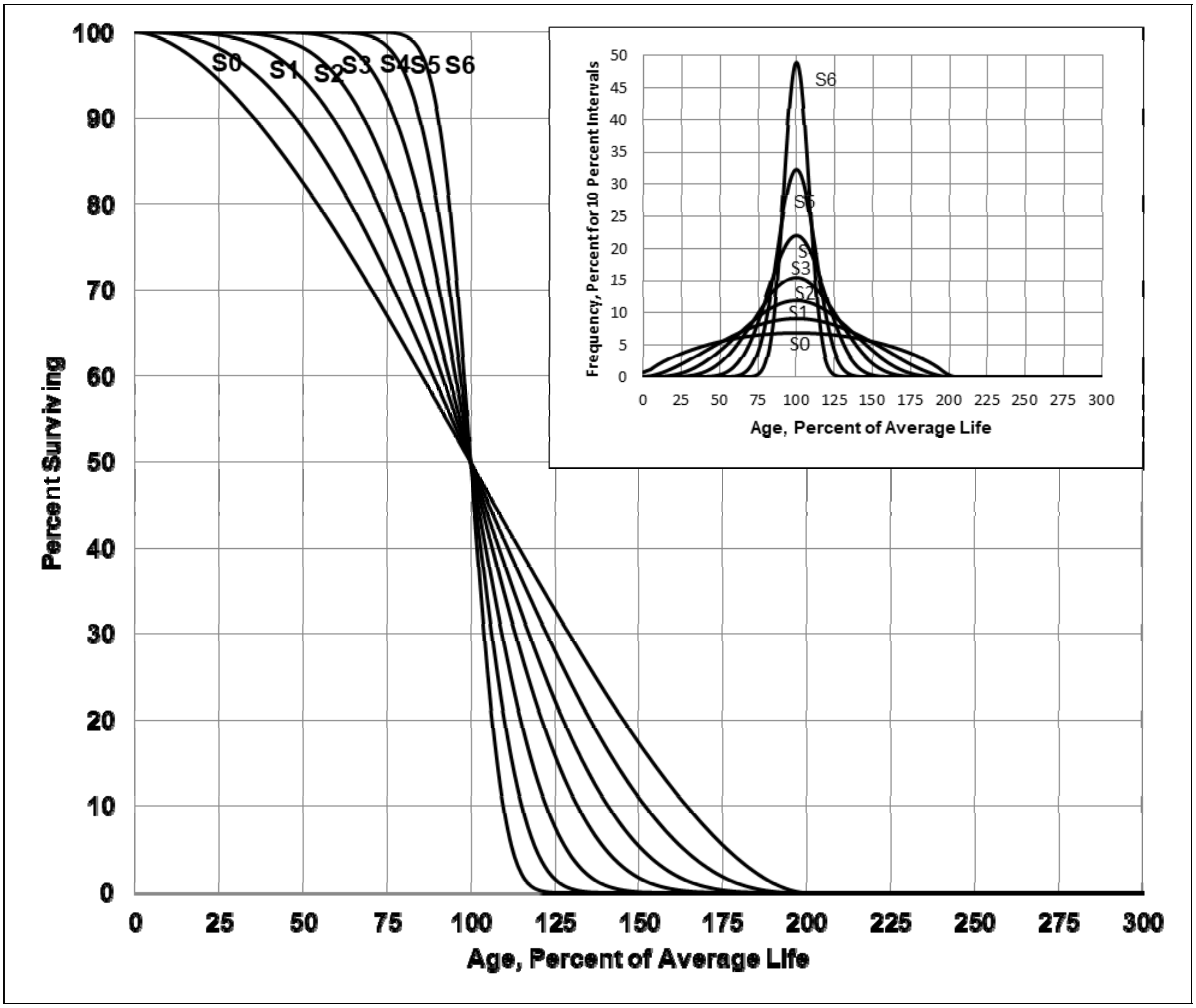
R-TYPE IOWA SURVIVOR CURVES



11

Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. The higher the number of the curve, the greater the peak. A graph showing the S curves is shown below.

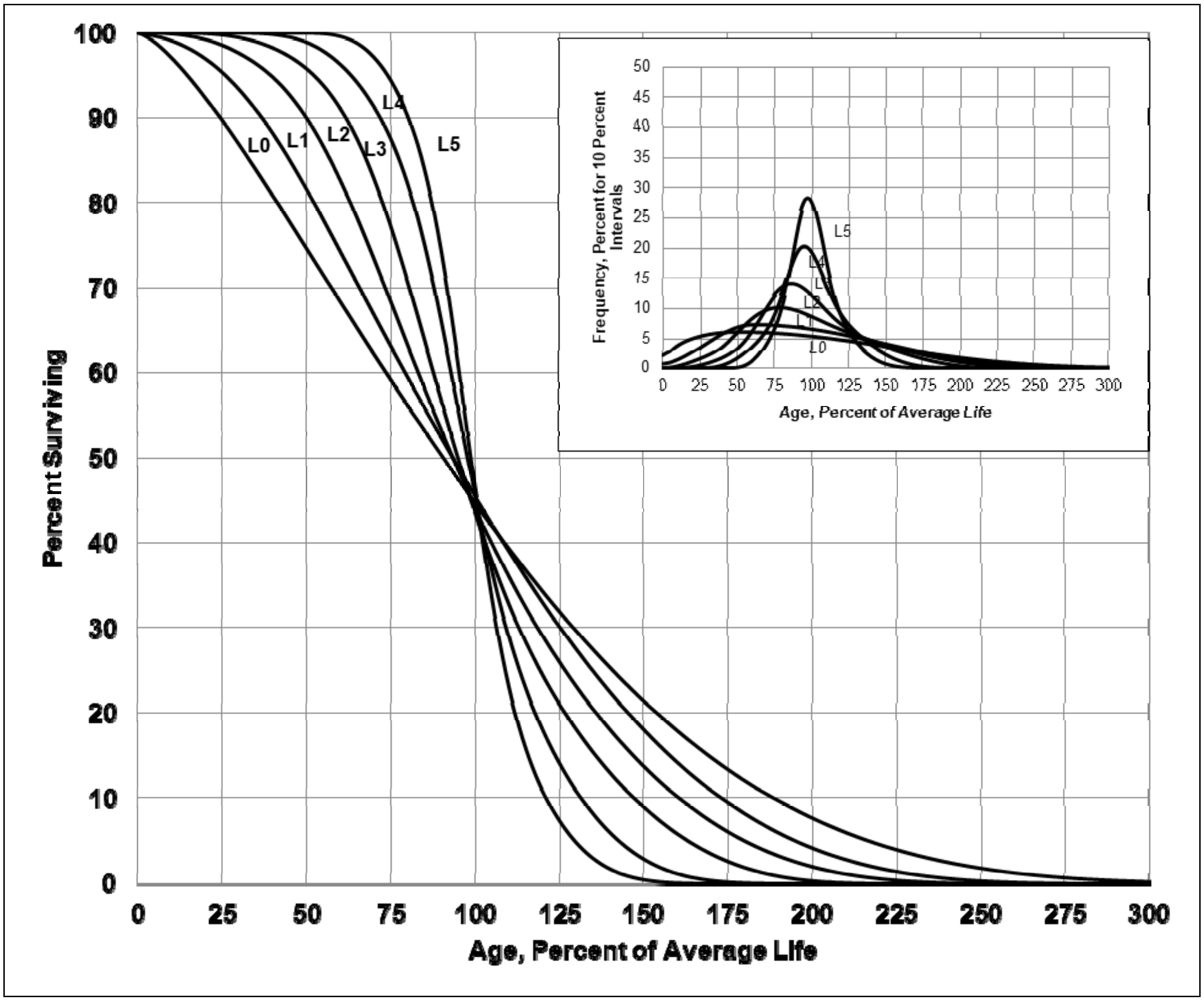
S-TYPE IOWA SURVIVOR CURVES



12

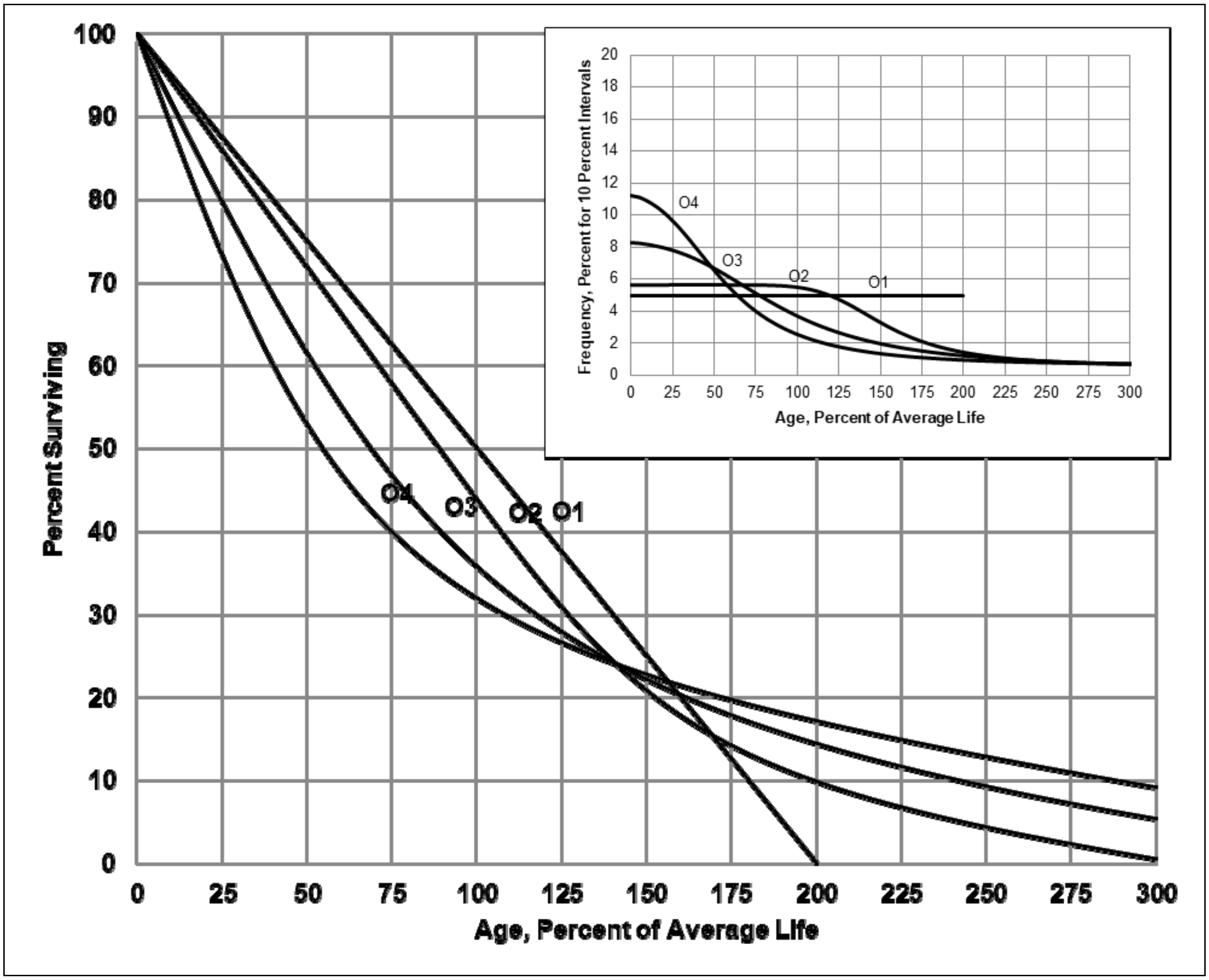
For distributions with the mode age less than the average life, a "L" designation (i.e., Left modal) is used. The family of "L" moded curves is shown below.

L-TYPE IOWA SURVIVOR CURVES



A special case of left modal dispersion is the "O" or origin modal curve family which was developed in the 1950s.

O-TYPE IOWA SURVIVOR CURVES



Given how long the O curves live, the O curves are seldom used in analyzing utility property in Alliance's experience. The O curves have been used for intellectual property.

14

Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency), while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data was available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Where data was available, accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience bands were used to focus on retirement history for all vintages during a set period. The results from these analyses for those accounts which had data sufficient to be analyzed using this method are shown in the Life Analysis section of this report.

Judgment

Alliance Consulting Group is an international consulting firm formed in 2004 by Dane Watson. In addition to Mr. Watson, Alliance also has three full-time Senior Consultants, Dr. Karen Ponder, Ms. Rhonda Watts, and Ms. Rebecca Richards, as well as other support staff. Alliance is dedicated to providing quality consulting and expert services to the utility industry. Our professionals have more than 120 years of combined experience around the utility industry, and have been employed in the industry as utility employees and consultants. Alliance has performed over 290 depreciation studies for electric, gas, steam, water, wastewater, cable, and communications utilities across North America since its founding by Mr. Watson in 2004. These utilities encompass regulated, non-regulated, municipal, and federal agencies. The résumés of our personnel and a listing of our many engagements is provided in Appendix F. Given Alliance personnel's experience in accounting, fixed assets, engineering, and depreciation theory, we have an unparalleled expertise in analyzing the Company's assets and recommending depreciation accrual rates.

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least, for example, any analysis requires choosing which bands to place more emphasis.

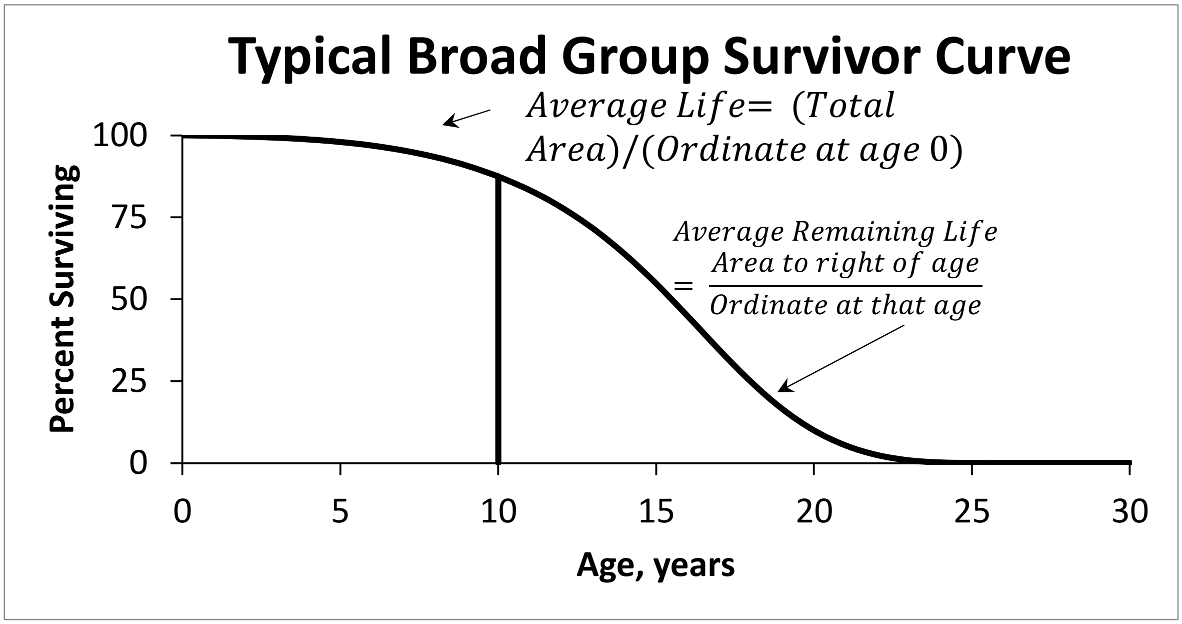
The establishment of appropriate average service lives and retirement dispersions for Hydro One Remote's plant accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

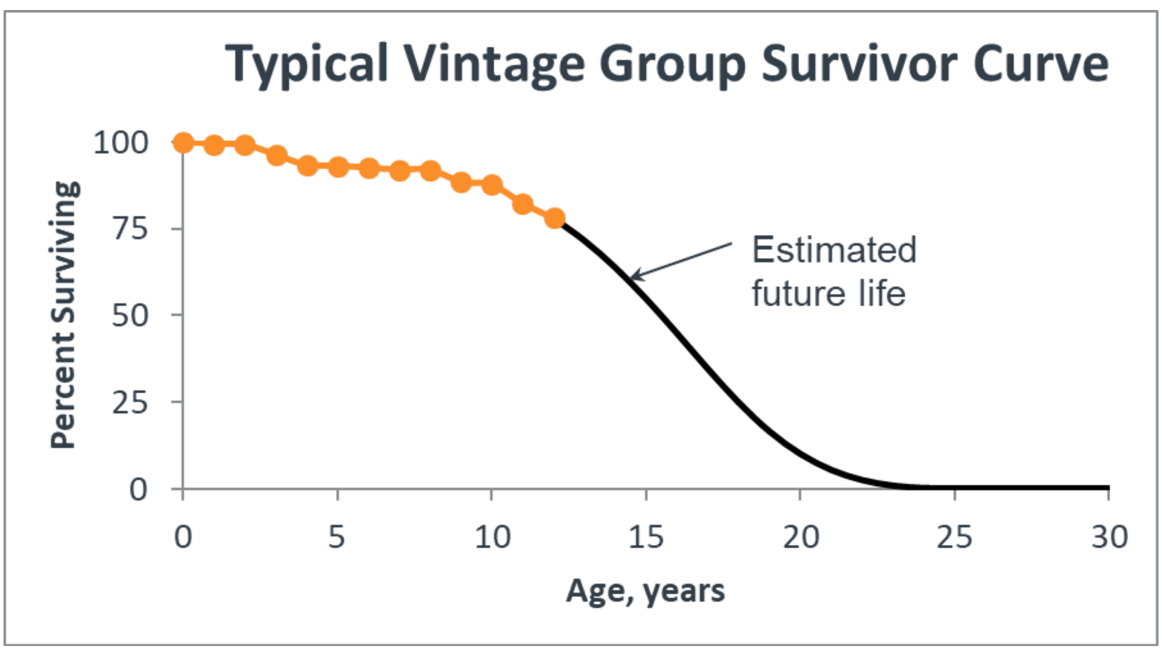
Average Life Group Depreciation

There are two depreciation "groupings" most commonly used in average life group depreciation: broad group and vintage group. Broad group ("BG") assumes that all units of plant in a plant account are considered to be one group. The BG produces stable results over many periods and is, in Alliance's experience, the most common depreciation system used across the industry. The vintage group ("VG") application assumes that each vintage within a plant account is a separate group. VG requires that each vintage group be analyzed separately to determine its average life, and then average lives of all vintages are composited to produce an average life for the group.

A typical broad group survivor curve is shown below.



VG uses the stub survivor curve of each vintage and determines remaining life from the proposed survivor curve. A typical vintage group curve model is shown below.



18

This study proposes to convert to the average life group, BG depreciation system to group the assets within each account. In its last depreciation study, Hydro One Remote was authorized to use the straight line, vintage group, remaining life ("SL-VG-RL") depreciation system. In Alliance's experience, the BG procedure is much more commonly used across North America. Since Hydro One Remote has limited transactional data from 2000-2021, the results from the VG procedure are more subject to fluctuations in computing individual vintage average service life if there are any anomalies in the data. Those changes in individual vintages could produce unstable results if there is incomplete data for an individual vintage. BG was selected as the depreciation system to use for Hydro One Remote in this study given that it is more stable in the accrual rate computations and used by the majority of North American utilities.

Theoretical Depreciation Reserve and Reserve Rebalancing

The book depreciation reserve was derived from Company records at the individual account level. This study used a reserve model that relied on a prospective concept relating to future retirement and accrual patterns for property, given current life and salvage estimates. This study recommends and uses reserve reallocation to rebalance reserves within each business unit and function. Reserve reallocation is when the book reserve is re-spread within a functional group based on the theoretical reserve within each function. In the process of analyzing the Company's depreciation reserve, Alliance observed that the depreciation reserve positions of the accounts were generally not in line with the life characteristics found in the analysis of the Company's assets. To allow the relative reserve positions of each account within a function to mirror the life characteristics of the underlying assets, we reallocated the depreciation reserves for all accounts within each function.

The depreciation reserve represents the amounts that have been collected as a systemic allocation of the cost of an asset over its useful life, including any net salvage that may be required to remove that asset from service upon retirement. The reallocation process does not change the total reserve for each function; it simply reallocates the reserve between accounts in the function. Depreciation reserve allocation is a sound depreciation practice. The National Association of Regulatory Utility Commissioners endorsed the practice in its 1968 publication of *Public Utility Depreciation Practices*, explaining that reallocation of the depreciation reserve is appropriate "…where the change in the view concerning the life of property is so drastic as to indicate a serious difference between the theoretical and the book reserve."[2] Additionally, the 1996 edition of *Public Utility Depreciation Practices* states that "theoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts."[3]

---

2 *Public Utility Depreciation Practices*, Published by the National Association of Regulatory Utility Commissioners, 1968, page 48.
3 *Public Utility Depreciation Practices*, Published by the National Association of Regulatory Utility

The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The average life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the group is retired. Estimated average service lives and dispersion determine the amount within each average life group. The straight-line remaining-life theoretical reserve ratio at any given age (RR) is calculated as:

$$RR = 1 - \frac{(Average\ Remaining\ Life)}{(Average\ Service\ Life)} * (1 - Net\ Salvage\ Ratio)$$

In the case of Hydro One Remote, no net salvage is incorporated in depreciation accrual rates, consistent with other Canadian utilities. Reserve reallocation has been used in the Company's previous transmission and distribution depreciation studies.

Commissioners, 1996, page 188.

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis were evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and documentation of the corresponding recommendations.

During the Phase 1 data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Also, as part of the Phase 1 data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the company's actual asset utilization and environment. Information that was gleaned in these discussions is found in the Detailed Discussion of this study in the life analysis sections.

Phase 2 is where the actuarial analysis is performed. Phases 2 and 3 overlap to a significant degree. The detailed property records information is used in Phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation process performed in Phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. No net salvage is incorporated in Hydro One Remote's depreciation accrual rates, consistent with its accounting practices, with other Canadian utilities, and with its previous studies. Net salvage was not included in the Company's prior Transmission, Distribution, and Common depreciation studies. This information was then carried forward into Phase 3 for the evaluation process.

Phase 3 is the evaluation process which synthesizes analysis, interviews, and operational characteristics into a final selection of asset lives and mortality curve parameters. The historical analysis from Phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[4] documents the steps used in conducting this study. Depreciation Systems[5], page 289, documents the same basic processes in performing a depreciation study which are: statistical analysis, evaluation of statistical analysis, discussions with management and operational personnel, forecast assumptions, and documented recommendations.

[4] Public Utility Finance & Accounting, A Reader.

[5] Depreciation Systems, by Drs. W. C. Fitch and F.K. Wolf, Iowa State University Press, 1994, page 289.

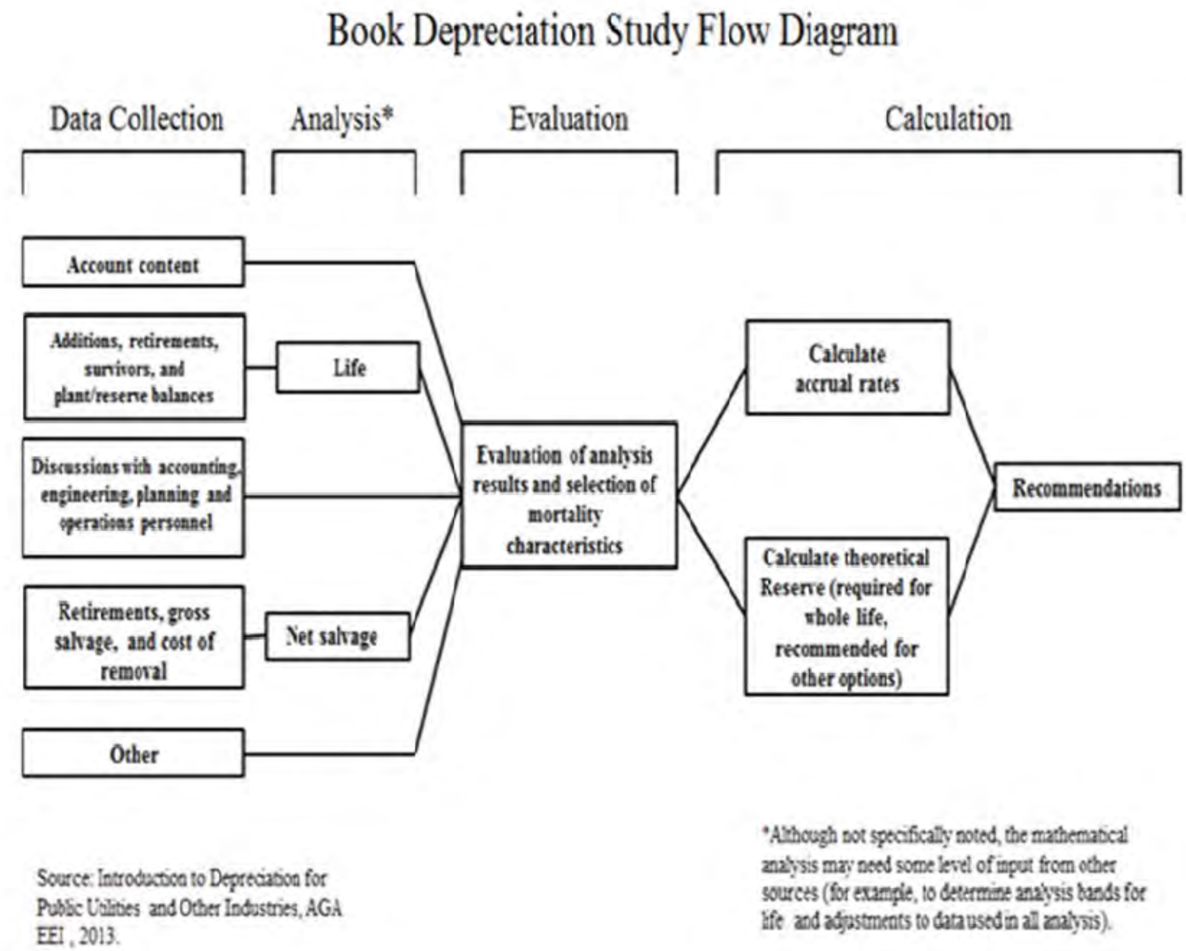


Figure 1

HYDRO ONE REMOTE COMMUNITIES DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation Process

The proposed rates are based on plant and accumulated depreciation reserve balances at December 31, 2021 and will be used in the Cost of Service Application. Annual depreciation expense amounts for all accounts were calculated by the straight-line method, broad (average) life group procedure, remaining-life technique. These calculations are shown in Appendix A. The results of calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in Appendix D. Book depreciation reserves were based on Company individual accounts and the theoretical reserve computation was used to rebalance depreciation reserves and compute a composite remaining life for each account.

LIFE ANALYSIS

The retirement rate actuarial analysis method was applied to all accounts for Hydro One Remote. For each account, an actuarial retirement rate analysis was made with placement and experience bands of varying widths. The historical observed life table was plotted and compared with various Iowa Curves to obtain the most appropriate match. A representative curve for each account is shown in the Life Analysis Section of this report.

Company history is compiled to develop observed survivor curves, which are matched against the Iowa Curve families discussed earlier. An observed survivor curve that does not reach 0% surviving is a stub curve. Because the average life associated with a survivor curve is represented by the area under the complete survivor curve, the observed survivor curve must be smoothed and extended to 0% surviving. If more historical data is available to analyze, the observed survivor curve (stub curve) will be longer (i.e., getting closer to 0 percent surviving). Hence the more history available in the data, the more predictable and reliable the resulting Company observed survivor curve will be for selecting a complete survivor curve. It is desirable to have the stub curve drop below 50% surviving. The earliest experience year available where retirement history for each account was available was 2003. Some of the Company's assets have existing lives longer than 50 years, and the observed life tables may not reach the desired 50% surviving.

For each account on the overall band (i.e., placement from earliest vintage year which varied for each account through 2021), approved survivor curves from the prior study, if applicable, modified by subsequent orders, were used as a starting point. Then, using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (e.g., L, S, or R) as an obviously better match than others. The matching process relies on expert judgment to determine which portion of the curve to match. The next step was to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall experience band, different experience bands were plotted and analyzed. Next placement bands of varying width were plotted with each experience band discussed above. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. The goal of visual matching was to minimize the differential between the observed life table and Iowa Curve in the top and mid-range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

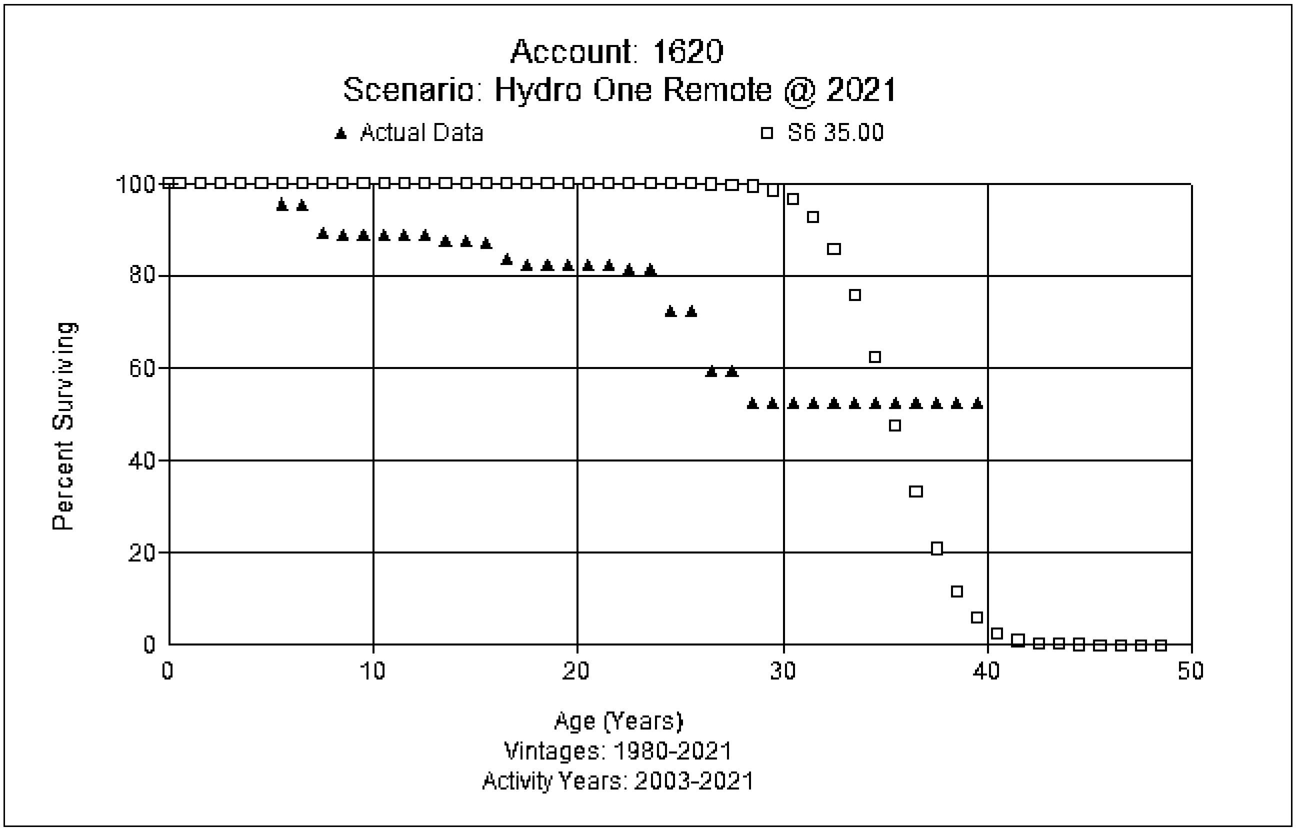
Since Hydro One Remote had aged data only going back to 2003, the short experience available for these long-lived accounts does not allow the observed life table to extend to a level that would allow the analyst to fully see the historical life cycles for the assets being studied. To help better understand the historical characteristic of the assets being studied, interviews with Company subject matter experts ("SMEs") provided valuable information used to estimate life characteristics. Company SMEs also provided estimated component lives for various assets in each plant account. The component life analysis for each business unit is found in Appendix E. The data in this study includes all retirement activity that Hydro One Remote has experienced between 2003-2021. By including all past events, this study expressly contemplates the range of natural disasters that Hydro One Remote has experienced in the past, along with the associated impact on early retirement of damaged or destroyed assets. Over time, natural events such as storms, flooding, or wildfires can occur and may cause the early retirement of assets. Such events have occurred during the period from 2003-2021 in Company history and will recur in the future given climate change and unknown future events.

GENERATION FUNCTIONAL GROUP

Assets in the depreciated groups accrue depreciation until the asset is retired or transferred. When an asset is fully accrued, the asset and its accumulated depreciation are transferred to a non-depreciable account, so no further accrual occurs.

Account 1620 Buildings and Fixtures (35 S6)

This account consists of building structures and other related assets used in electric generation. The plant balance in this account at December 31, 2021 is $6.5 million. Currently, the life of this account is 35 years with an S6 dispersion. Company SMEs report that they have not focused on these assets in the past. There are some shorter life indications from life analysis, but Company SMEs are not consistent with operational expectations. In the future the Company is more likely to do betterments than replace assets. After seeking input from Company personnel and incorporating professional judgment, the conclusion was that the existing life is still appropriate for this account. A graph comparing the observed life table to the proposed curve for this account is shown below, a 35-year life with an S6 dispersion.

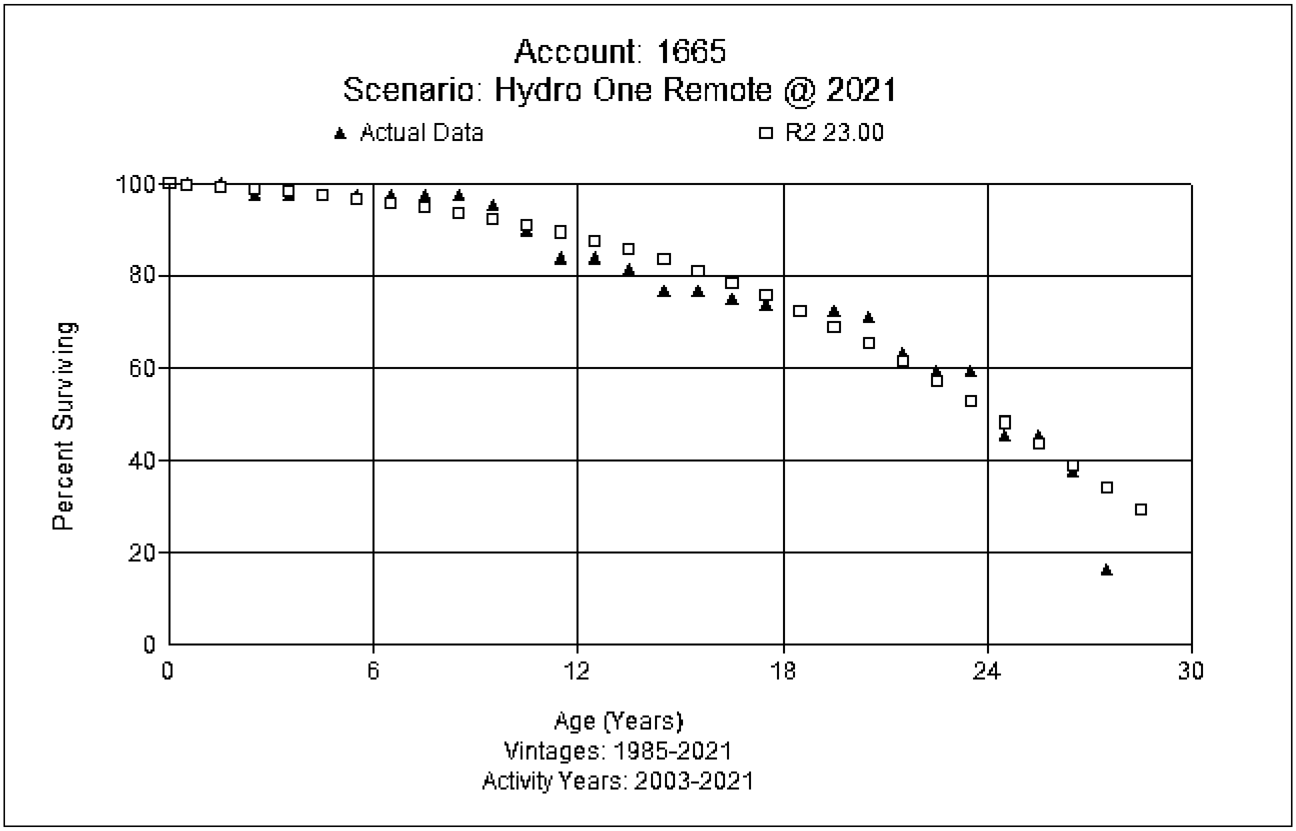

Account: 1620
Scenario: Hydro One Remote @ 2021
Actual Data
S6 35.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1980-2021
Activity Years: 2003-2021

29

Account 1665 Fuel Holders, Producers, and Accessories (23 R2)

This account consists of pumps, storage tanks, natural gas/fuel oil piping, and other related assets at each power plant. The plant balance in this account at December 31, 2021 is $8.5 million. Currently, the life of this account is 35 years with an S6 dispersion. Company personnel report that building codes have changed a great deal over time. Tanks that were installed in the 1980s and 1990s have been replaced to minimize risks. New tanks may last 35 years. A number of tanks are moving to backup power and the Company only uses one or two tanks. Some locations will have tanks decommissioned. Company SMEs report that approximately 10 tanks will be replaced prior to 35 years.

Additionally, nine of the communities that Hydro One Remote serves will be grid connected, which will lead to tanks being taken out of service. For example, Sandy Lake (which went in service in 2008) will have 5 of 8 tanks taken out of service. Another station is being connected to the grid and will be totally retired at the age of 10 years. The actuarial analysis gives indications in the 23-year range. Given these forces of retirement and the analytics, Company SMEs agree that reducing the life to 23 years is reasonable from an operational perspective. After seeking input from Company personnel, reviewing the available history, and incorporating professional judgment, the determination that reducing the existing life to a 23-year life with an R2 dispersion is appropriate for this account. A graph comparing the observed life table to the proposed curve for this account is shown below, a 23-year life with an R2 dispersion.



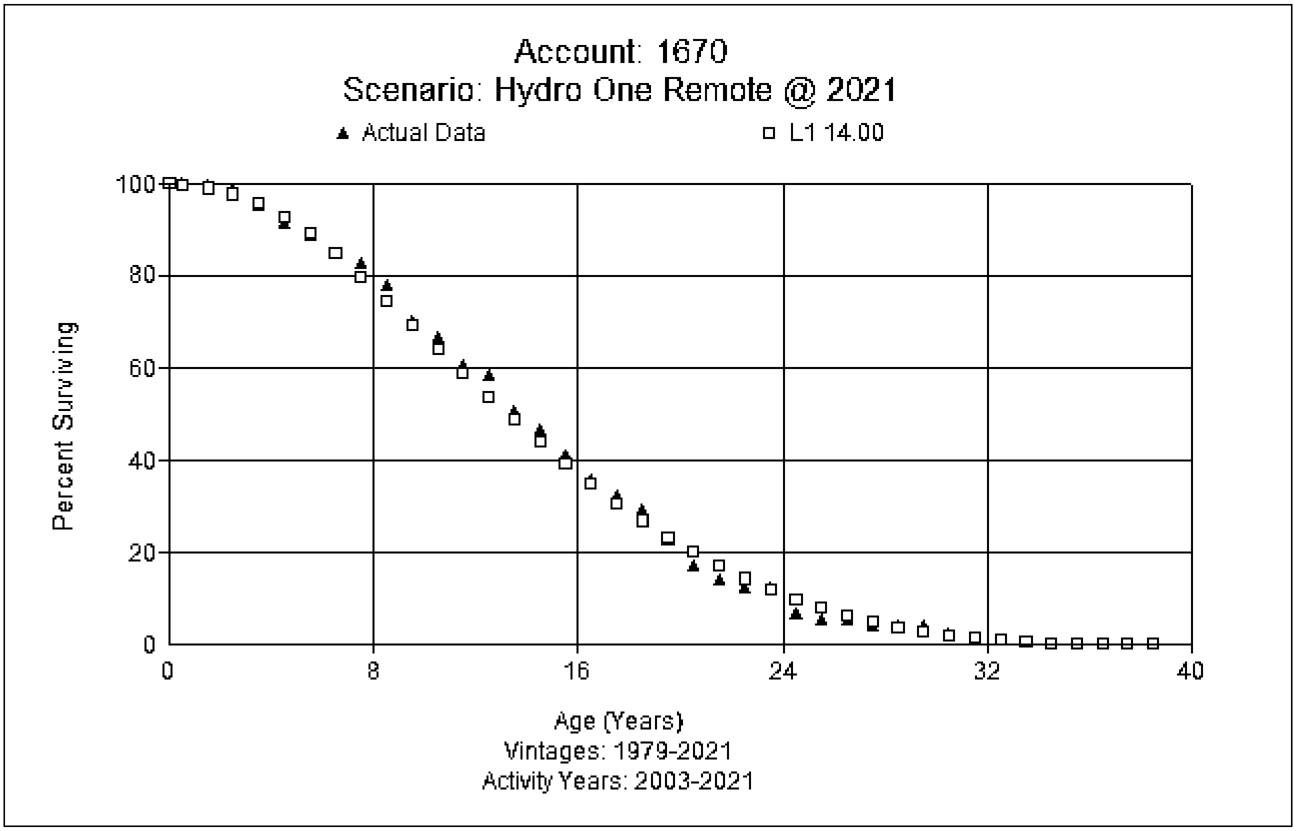
Account: 1665
Scenario: Hydro One Remote @ 2021
Actual Data
R2 23.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1985-2021
Activity Years: 2003-2021

31

Account 1670 Prime Movers (14 L1)

This account consists of prime movers and other related assets at each power plant. The plant balance in this account at December 31, 2021 is $17.9 million. Currently, the life of this account is 10 years with an S6 dispersion. Company SMEs report that assets are split between 75% for prime movers and 25% for generators. The Company will keep generators in service for at least the next 10 years. Some smaller prime movers (around a dozen) would be replaced at 20K hours, since it is cheaper to replace those than to refurbish them. Company experts agree that a life of 14 years makes sense from an operations perspective. For these reasons and the results of the analytics, a 14-year life with an L1 dispersion is recommended for this account. A graph comparing the observed life table to the proposed curve for this account is shown below, a 14-year life with an L1 dispersion.

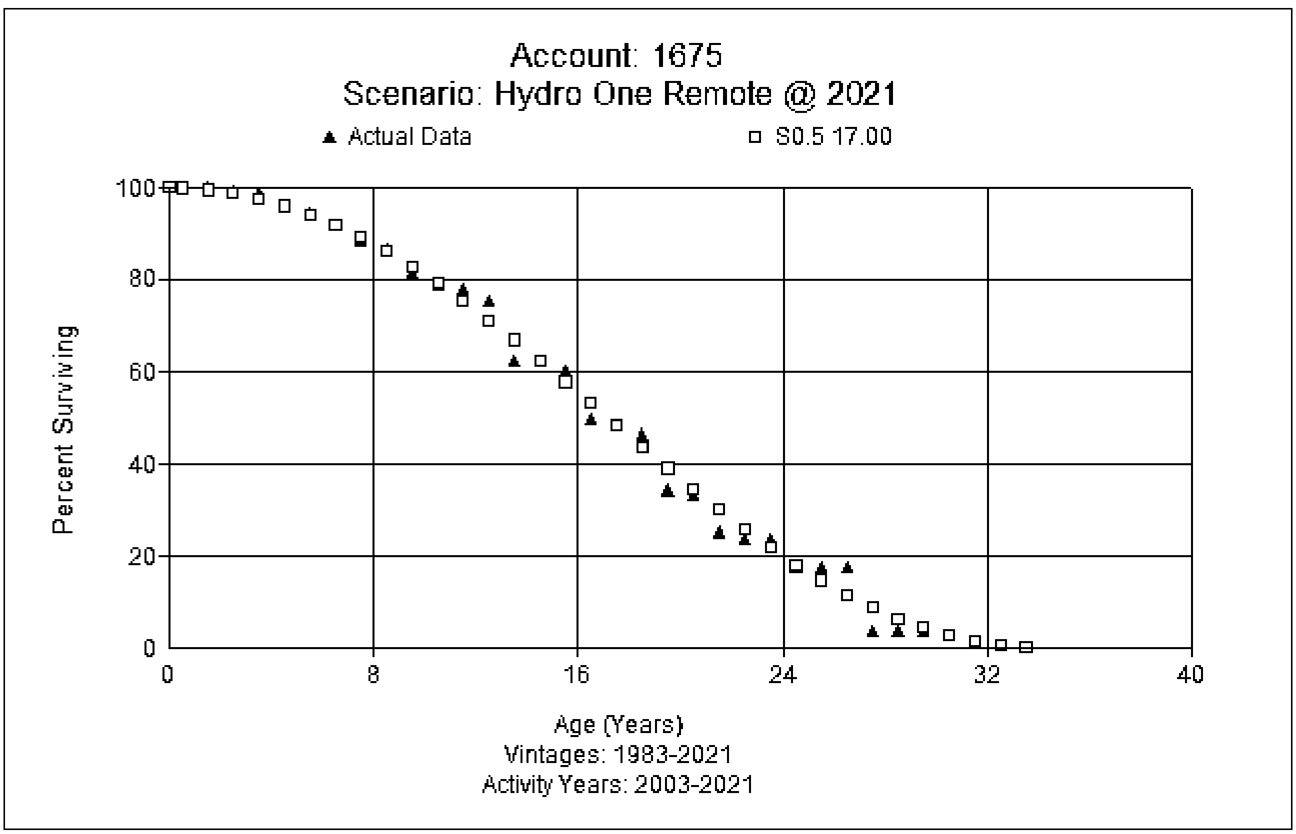
.


Account: 1670
Scenario: Hydro One Remote @ 2021
Actual Data
L1 14.00
Percent Surviving
100
80
60
40
20
0
0
8
16
24
32
40
Age (Years)
Vintages: 1979-2021
Activity Years: 2003-2021

33

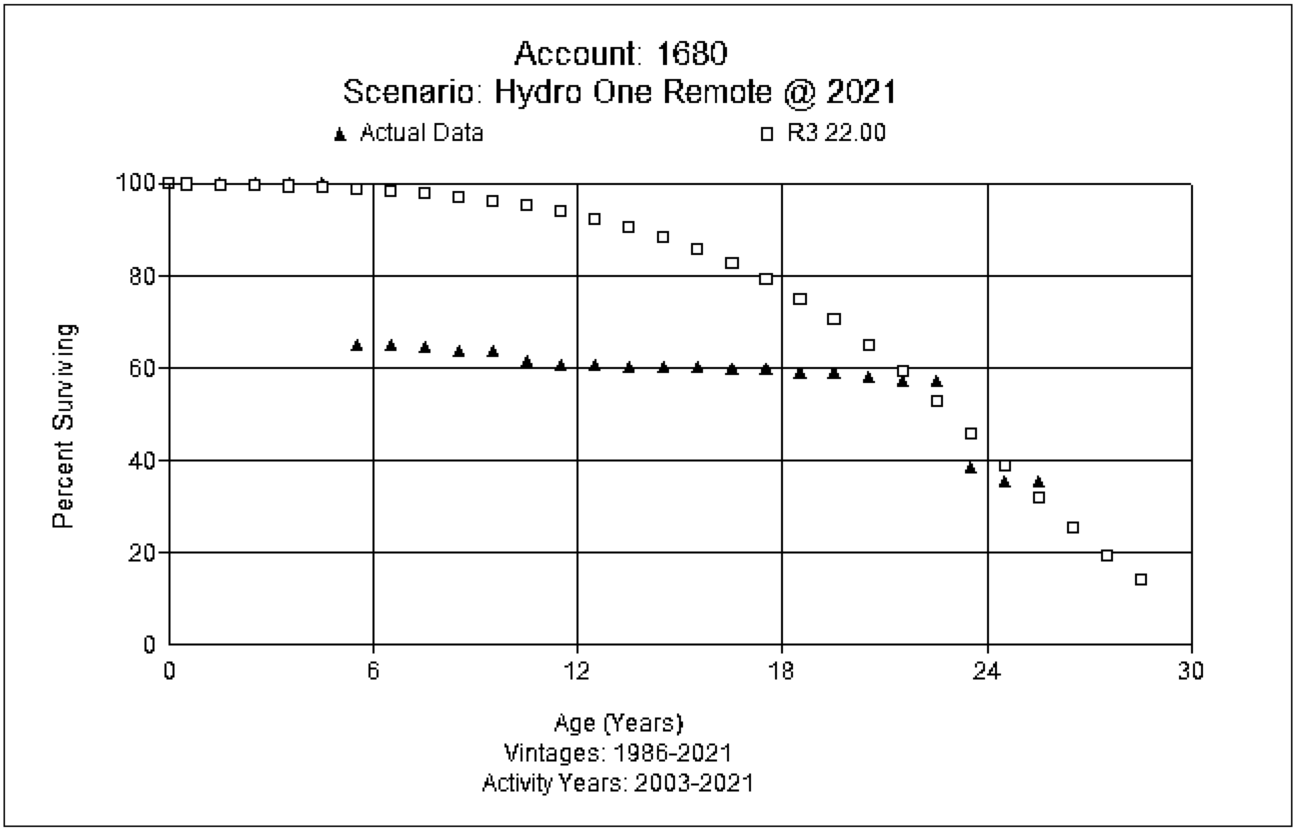
Account 1675 Generators (17 S0.5)

This account consists of generators, turbine equipment, and other related assets. The plant balance in this account at December 31, 2021 is $8.0 million. Currently the life of this account is 16 years with an S6 dispersion. Company personnel report that prime movers will sometimes be replaced without replacing the generator assets. Replacement will occur when assets reach 60K hours of run time. Company personnel report that replacing components of the small units early would have the effect of moving the generator life higher, since they would only replace the prime mover and not the generator. From an operations perspective, Company personnel agree that a 17-year life is reasonable. For the reasons listed above and from the analytics, a 17-year life with an S0.5 dispersion is recommended for this account. A graph comparing the observed life table to the proposed curve for this account is shown below, a 17-year life with an S0.5 dispersion.



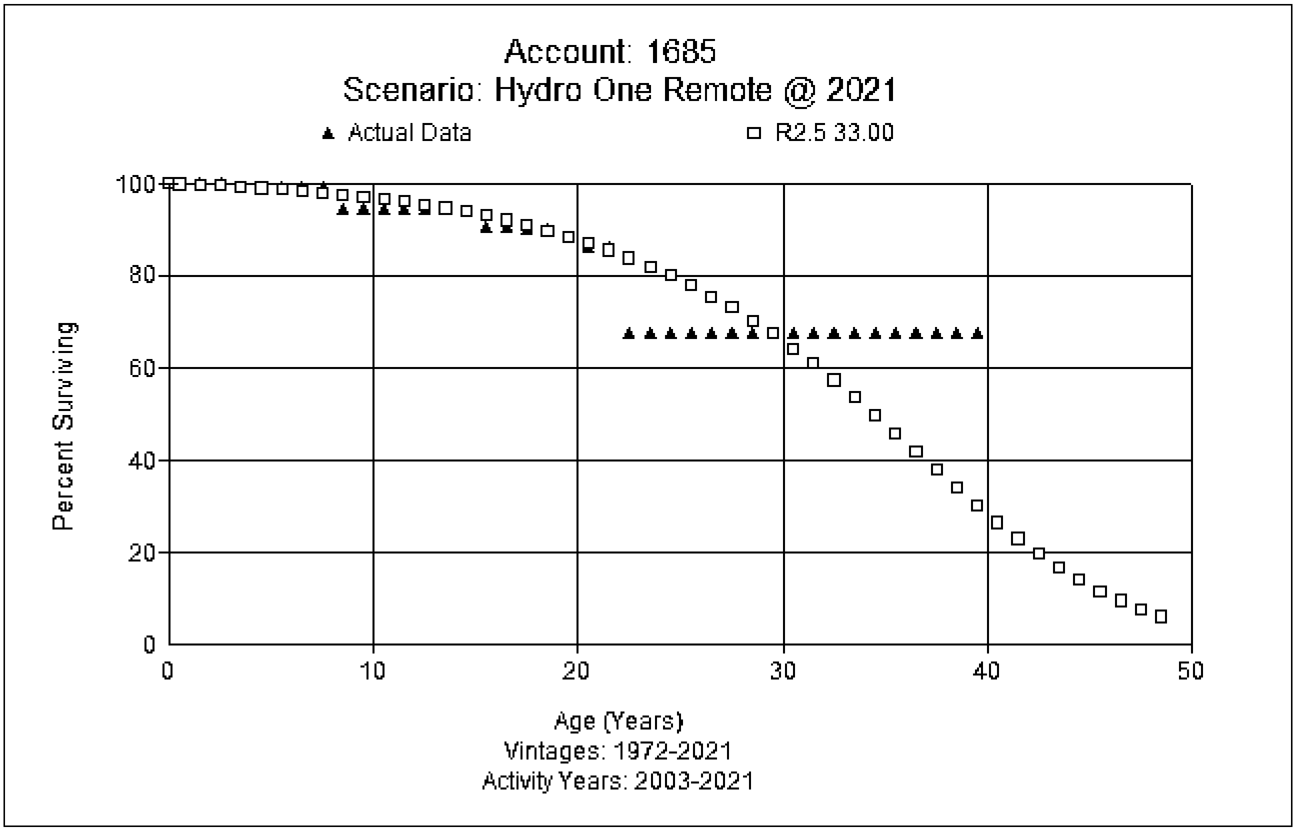
Account 1680 Accessory Electric Equipment (22 R3)

This account consists of power transformers, conduit, and other related assets at each power plant. The plant balance in this account at December 31, 2021 is $1.8 million. Currently the life of this account is 17 years with an S6 dispersion. The Company no longer has wind or solar generation. Company SMEs report that there are 12 station transformers that are 50 years old. Capacity is a driver of replacement of these assets, but that is not as important a driver as communities moving to the stations providing backup power. As transformers age, the average life will continue to increase. The Company will retire transformers in two communities, one at 12 years and one at 15 years. The remaining transformers are lasting longer due to community growth. For the reasons listed above, moving out to a 22-year life with an R3 dispersion is recommended for this account. A graph comparing the observed life table to the proposed curve for this account is shown below.


Account: 1680
Scenario: Hydro One Remote @ 2021
Actual Data
R3 22.00
Percent Surviving
100
80
60
40
20
0
0
6
12
18
24
30
Age (Years)
Vintages: 1986-2021
Activity Years: 2003-2021

Account 1685 Miscellaneous Power Plant Equipment (33 R2.5)

This account consists of work equipment, test equipment, pumps, fire protection systems, and other related assets at each power plant. The plant balance in this account at December 31, 2021 is $4.5 million. Currently the life of this account is 25 years with an S6 dispersion. In the 10 years, Company SMEs note that fire suppression systems are lasting longer than in the past. In the past, the Company would have changed out the whole system. Now, the Company is adding instead of replacing. The current life makes sense from a historical operational perspective, but Company experts note that moving stations to be backup systems is extending the life of some of these assets. Company SMEs believe that moving the life of these assets out 5 to 8 years makes sense operationally. For the reasons listed above, a 33-year life with an R2.5 dispersion is recommended for this account. A graph comparing the observed life table to the proposed curve for this account is shown below.



Account: 1685
Scenario: Hydro One Remote @ 2021
Actual Data
R2.5 33.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1972-2021
Activity Years: 2003-2021

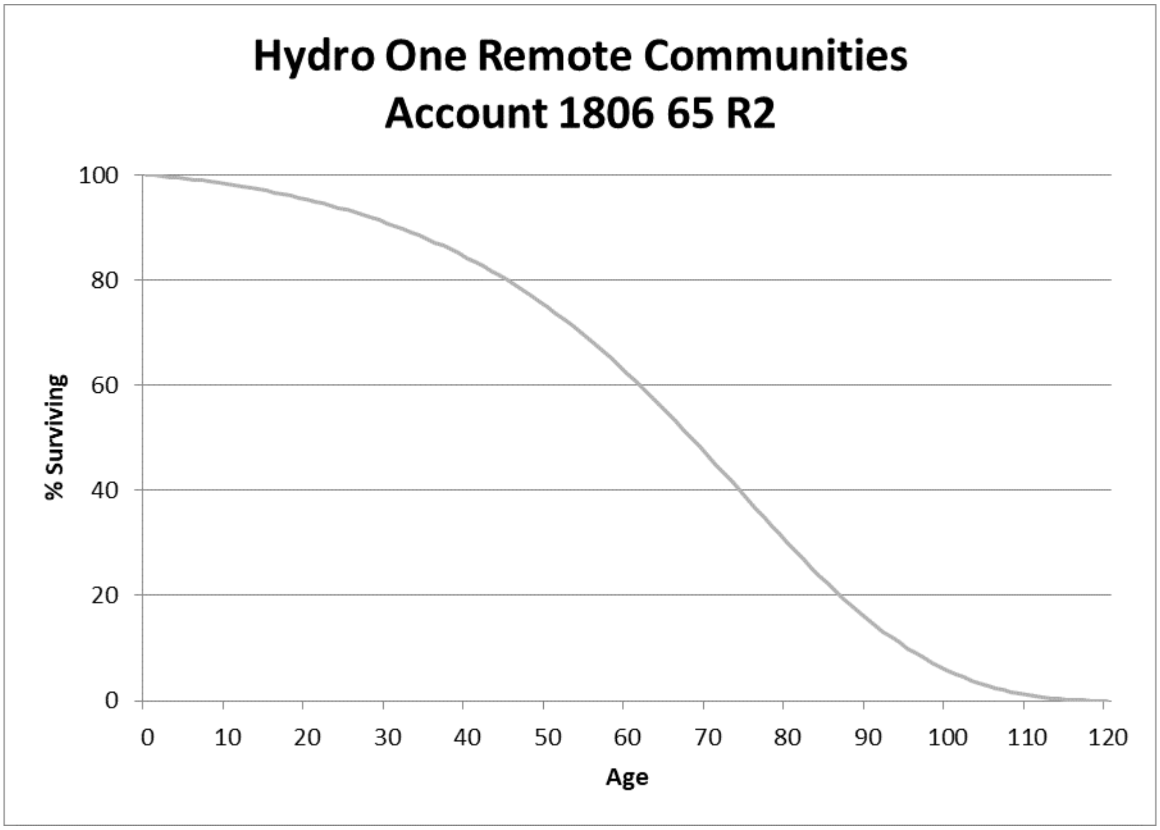
38

DISTRIBUTION FUNCTIONAL GROUP

Assets in the depreciated groups accrue depreciation until the asset is retired or transferred. When an asset is fully accrued, the asset and its accumulated depreciation are transferred to a non-depreciable account, so no further accrual occurs.

Account 1806 Improvements to Land Rights (65 R2)

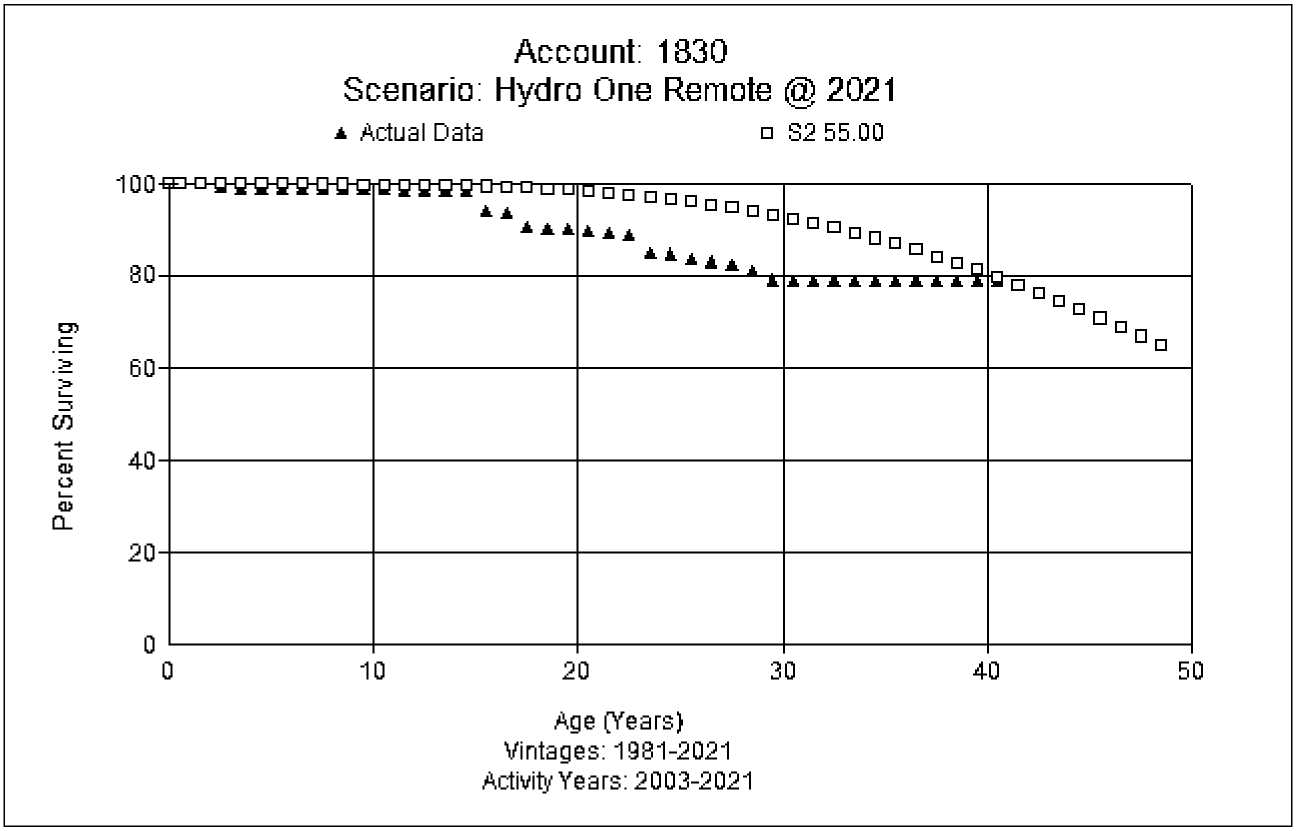
This account consists of land rights associated with Distribution Operations. Such assets include easements, site improvements, and improvements to Crown land. After the end of 2021, investment in another account was combined in this account. The plant balance in this account at December 31, 2021 is $529 thousand. Currently the life of this account is 100 years with an S5 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 100-year life is longer than appropriate for this account. The currently used S curve assumes that items retire symmetrically around the average life of the group. In Alliance's experience, retirement characteristics of property in this account model the R family where more assets live longer than the average service life of the group. Typically, the life of land rights is tied to the longest-lived assets on those rights. The longest estimated life of assets in this function is 65 years. Based on professional experience, we recommend shifting the life from the S family to the R family. For the reasons listed above, a 65-year life with an R2 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One Remote Communities
Account 1806 65 R2
100
80
60
40
20
0
% Surviving
0
10
20
30
40
50
60
70
80
90
100
110
120
Age

40

Account 1830 Poles Towers and Fixtures (55 S2)

This account consists of various poles, towers, and fixtures associated with Distribution Operations. Such assets include steel towers, steel poles, supports, composite poles, and other support devices. The plant balance in this account at December 31, 2021 is $4.1 million. Currently the life of this account is 55 years with an S2 dispersion. There are no poles older than 55 years. Assets in the Remote Communities are installed in a much colder environment than Hydro One, so the Company would expect a longer life from certain drivers of retirement than that seen in warmer climates because the forces for retirement such as rot and insects are less impactful. Although the analytics would suggest a shorter life, Company personnel believe that the life of this account would be at least as long as Hydro One Networks Inc. (BU 220 Account 1830 which is 55 years) and there are no operational reasons to suggest a shorter life. There are some poles in Armstrong that date from the 1950s, but the Company is also changing out some poles from the 1970s and 1980s. Based on input from Company experts, this study recommends retention of the existing 55-year life with an S2 dispersion. A graph comparing the observed life table to the proposed curve for this account is shown below.



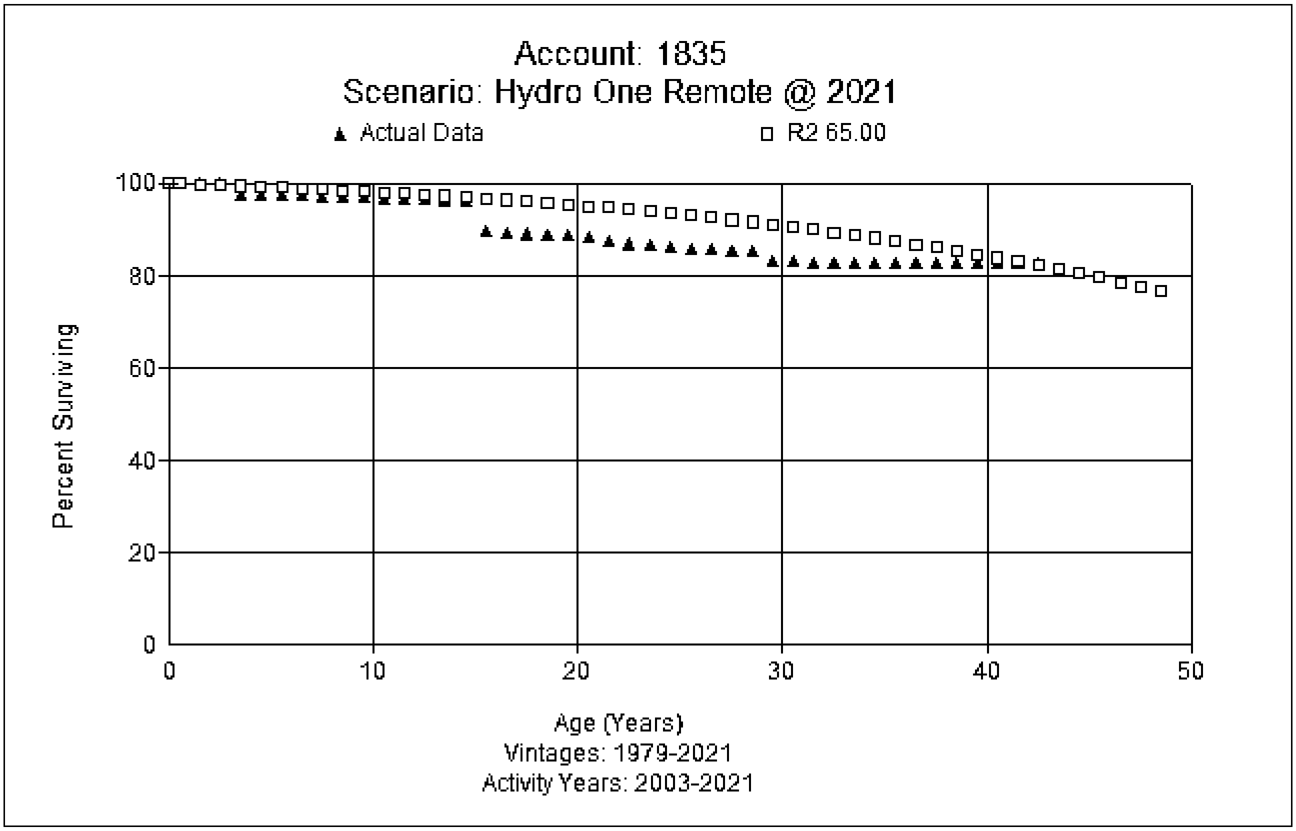
Account: 1830
Scenario: Hydro One Remote @ 2021
Actual Data
S2 55.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1981-2021
Activity Years: 2003-2021

42

Account 1835 Overhead Conductor and Devices (65 R2)

This account consists of overhead conductor and devices associated with Distribution Operations. Such assets include grounding system, ground wires, insulators, conductor, switches, voltage regulators, and capacitors. The plant balance in this account at December 31, 2021 is $2.5 million. Currently, the life of this account is 50 years with an S2 dispersion. Company SMEs expect conductor to last longer than poles. In the past, conductor was made of solid copper. Newer aluminum conductor with steel cores has different failure modes. Technology drives different (shorter) lives for switches/interrupters than for conductor. Company experts believe that ACSR conductor would last longer than earlier types.

The Company does not heavily load conductor and there are few forces of contamination (if any) to shorten the life. Company SMEs report that they robustly engineer their system so that it is not necessary to "touch" assets often, with the goal of making the system "trouble proof". Company SMEs report that they use short spans and Class 3 poles. Company experts report that they believe the life should be longer at around 60 or 65 years. Considering the recommendation for the life of conductor compared to poles, this study recommends a 65-year life with an R2 dispersion for this account. A graph comparing the observed life table to the proposed curve for this account is shown below.

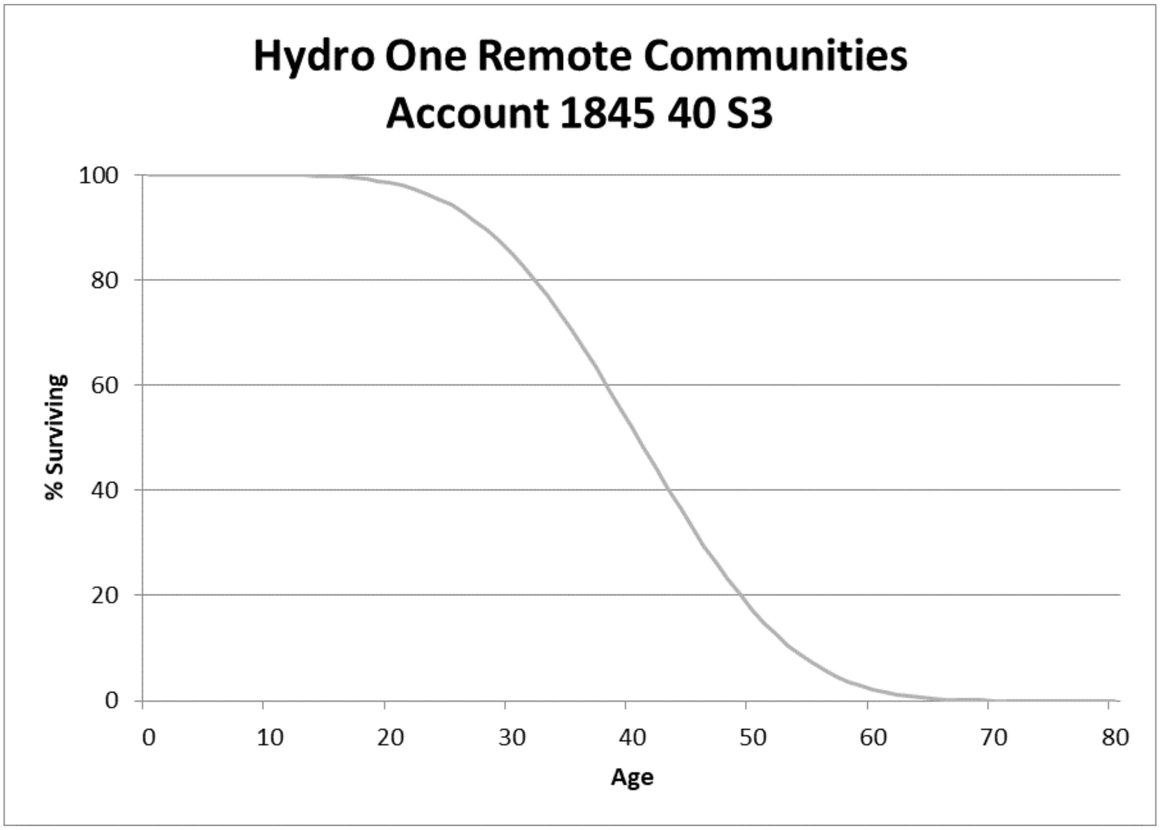


Account: 1835
Scenario: Hydro One Remote @ 2021
Actual Data
R2 65.00
Percent Surviving
100
80
60
40
20
0
0
10
20
30
40
50
Age (Years)
Vintages: 1979-2021
Activity Years: 2003-2021

44

Account 1845 Underground Conductors and Devices (40 S3)

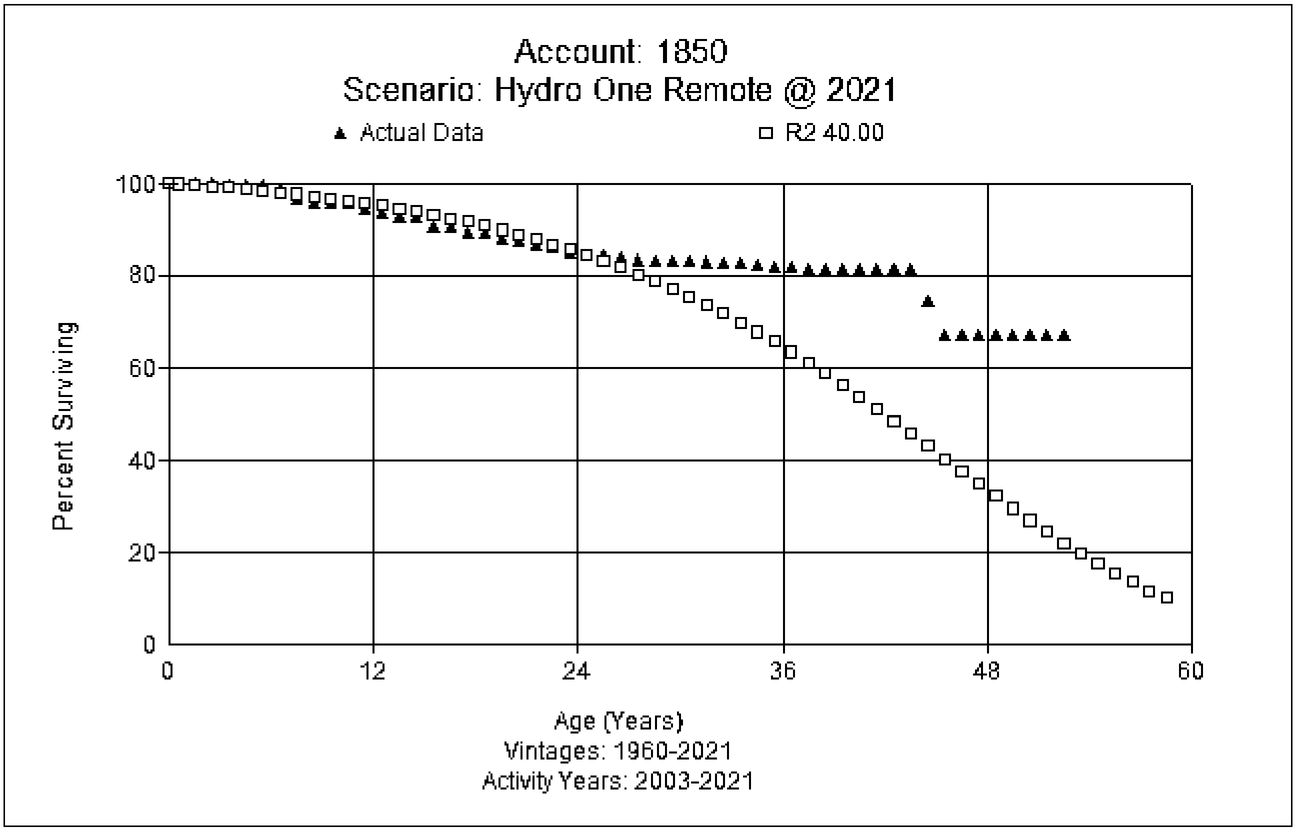
This account consists of various underground conductor and devices associated with Distribution Operations. Such assets include underground conductor, submarine cable, and fuse housing. The plant balance in this account at December 31, 2021 is $292 thousand. Currently, the life of this account is 30 years with an S3 dispersion. Company personnel report that, at times, they use submarine cable depending on the site. Underground primary is generally installed around airports. The majority of assets in this account are older than 30 years. Over the available period from 2003-2021, there have been no retirements. No replacements have occurred that Company experts are aware of. Operationally, Company experts expect a longer life, and they recommend moving the life of this account to 40 years. After seeking input from Company personnel and incorporating professional judgment, a 40-year life with an S3 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One Remote Communities
Account 1845 40 S3
100
80
60
40
20
0
% Surviving
0
10
20
30
40
50
60
70
80
Age

46

Account 1850 Line Transformers (40 R2)

This account consists of various types of line transformers associated with Distribution Operations. Such assets include overhead transformers, underground transformers, capacitors, and other similar equipment. The plant balance in this account at December 31, 2021 is $2.5 million. Currently, the life of this account is 40 years with an R2 dispersion. Company experts report that older transformers will have a longer life than the newer generations. Some areas still have transformers from the 1950s. The Company lightly loads transformers. Hydro One Remote transformers have less exposure to lightning, and the Company over-sizes transformers. They upgrade transformers much more frequently than in the past, in part due to electric heat becoming more prominent in their service territory. Generally, the Company reuses newer transformers when replacements occur. At this time, the Company usually disposes of any transformer from years 1985 and older. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 40-year life is still appropriate for this account. For the reasons listed above, retaining a 40-year life with an R2 dispersion is recommended for this account. A graph comparing the observed life table to the proposed curve for this account is shown below.

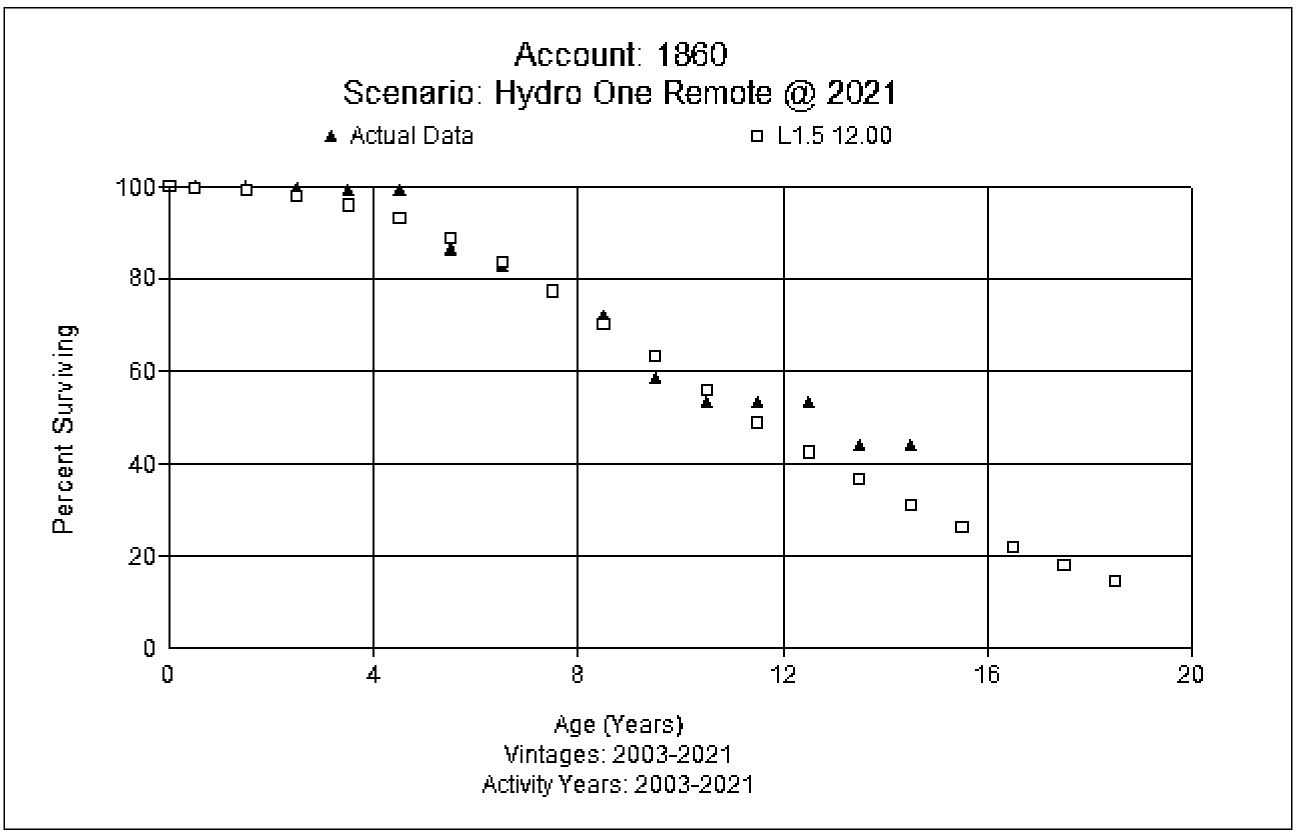


Account: 1850
Scenario: Hydro One Remote @ 2021
Actual Data
R2 40.00
Percent Surviving
100
80
60
40
20
0
0
12
24
36
48
60
Age (Years)
Vintages: 1960-2021
Activity Years: 2003-2021

48

Account 1860 Meters (12 L1.5)

Account 1860 consists of various meters associated with Distribution Operations. Such assets include watt meters, demand meters, and all other meter equipment. The plant balance in this account at December 31, 2021 is $1.3 million. Currently, the life of this account is 15 years with an R5 dispersion. The Company reads digital meters manually. Cold weather harms LED displays and forces replacement of the meters more frequently than in warmer areas. Hydro One Remote changed out all analog meters over the last 10 years, and now only digital meters are in service. Company SMEs believe a shorter life than that seen in warmer climates is appropriate. For the reasons listed above and the indications from the analytics, a 12-year life with an L1.5 dispersion is recommended for this account. A graph comparing the observed life table to the proposed curve for this account is shown below.



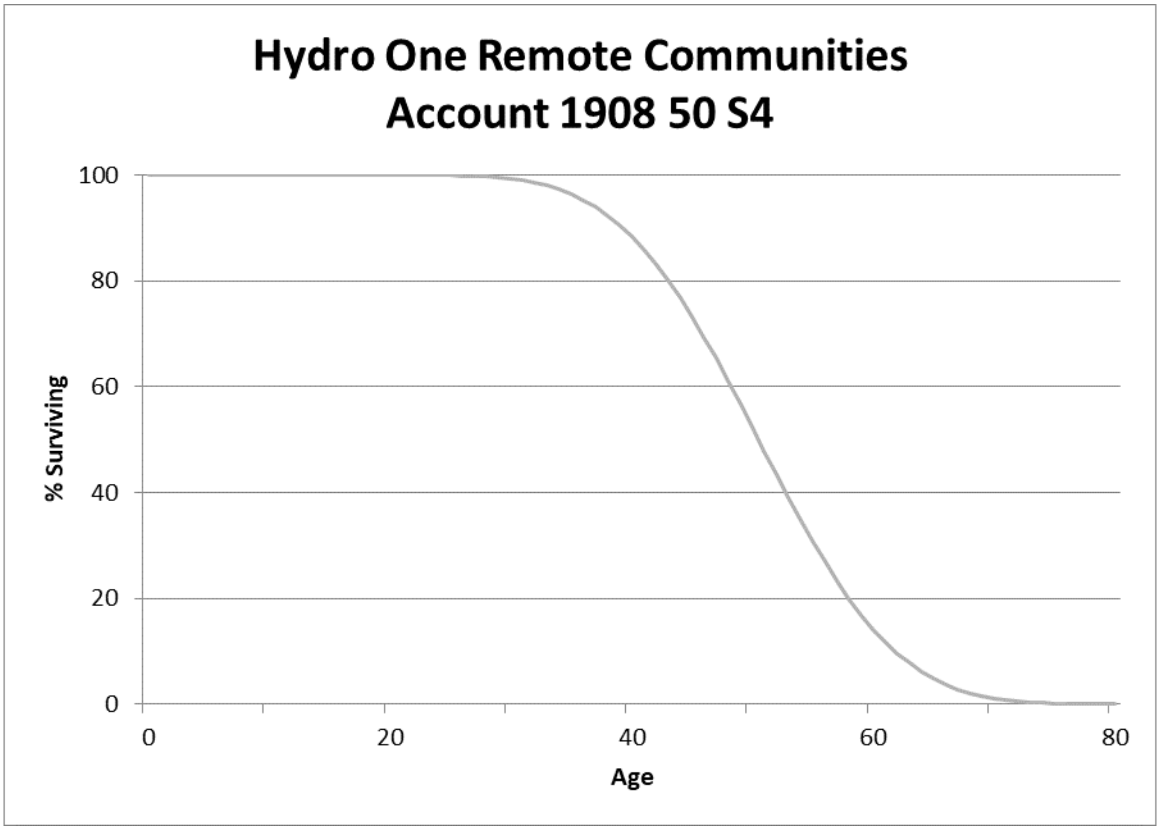
49

GENERAL DEPRECIATED FUNCTIONAL GROUP

Assets in the depreciated groups accrue depreciation until the asset is retired or transferred. When an asset is fully accrued, the asset and its accumulated depreciation are transferred to a non-depreciable account, so no further accrual occurs.

Account 1908 Buildings and Fixtures (50 S4)

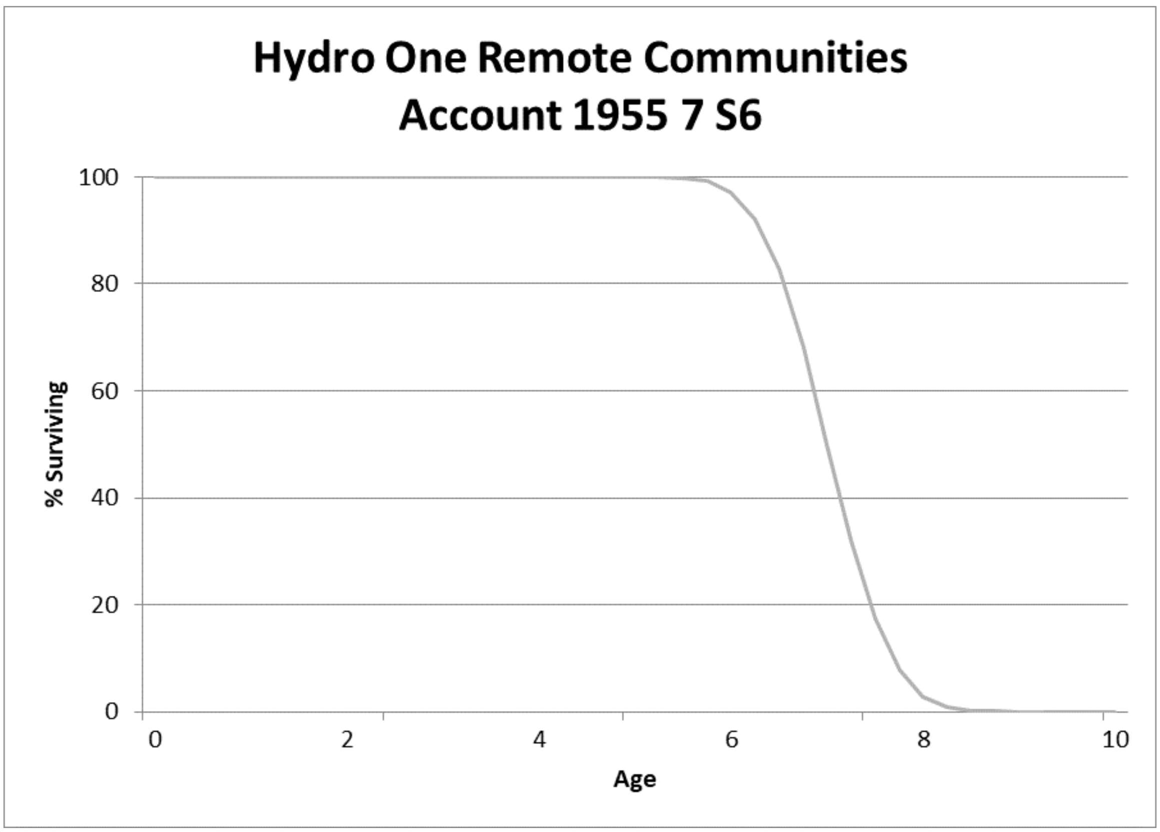
This account consists of various buildings and fixtures. Such assets include buildings, landscaping, fencing, roads and surfaces, and other structures. The plant balance in this account at December 31, 2021 is $12.4 million. Currently the life of this account is 50 years with an S4 dispersion. There is one service center in Thunder Bay, which is the headquarters. The Company is considering expanding the facility, but no determination has been made. Other buildings are staff housing in communities where no change in life is anticipated. Overall, Company SMEs do not expect a material change in the life of this account. Retention of a 50-year life with an S4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One Remote Communities
Account 1908 50 S4
100
80
60
40
20
0
% Surviving
0
20
40
60
80
Age

51

Account 1955 Communication Equipment (7 S6)

This account consists of various communication equipment. Such assets include telecom equipment, switching equipment, radios, optical wire, fiber optic cable, and power supply equipment. The plant balance in this account at December 31, 2021 is $20 thousand. Currently, the life of this account is 7 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 7-year life is still appropriate for this account. For the reasons listed above, a 7-year life with an S6 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.

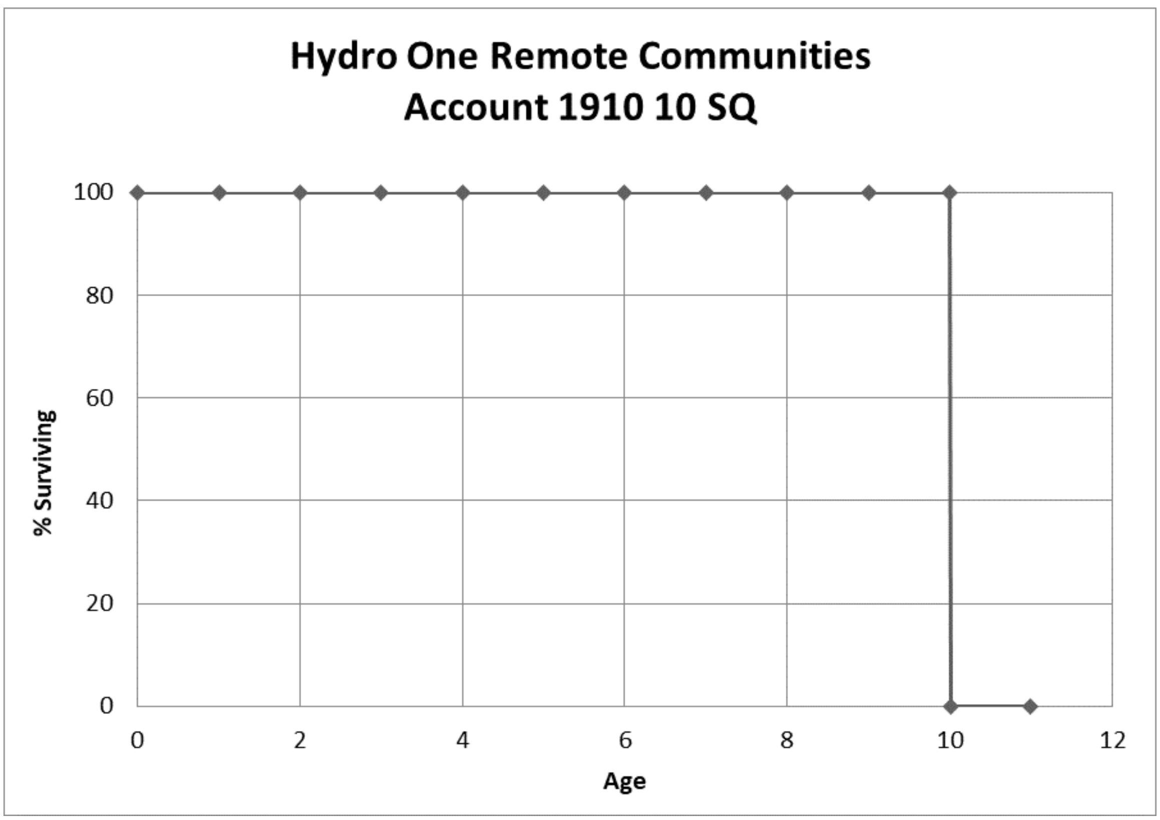


GENERAL AMORTIZED FUNCTIONAL GROUP

Accounts in the general amortized function are amortized. When those assets are fully accrued, amortization ceases. Any new assets added are amortized using the life assigned to the account.

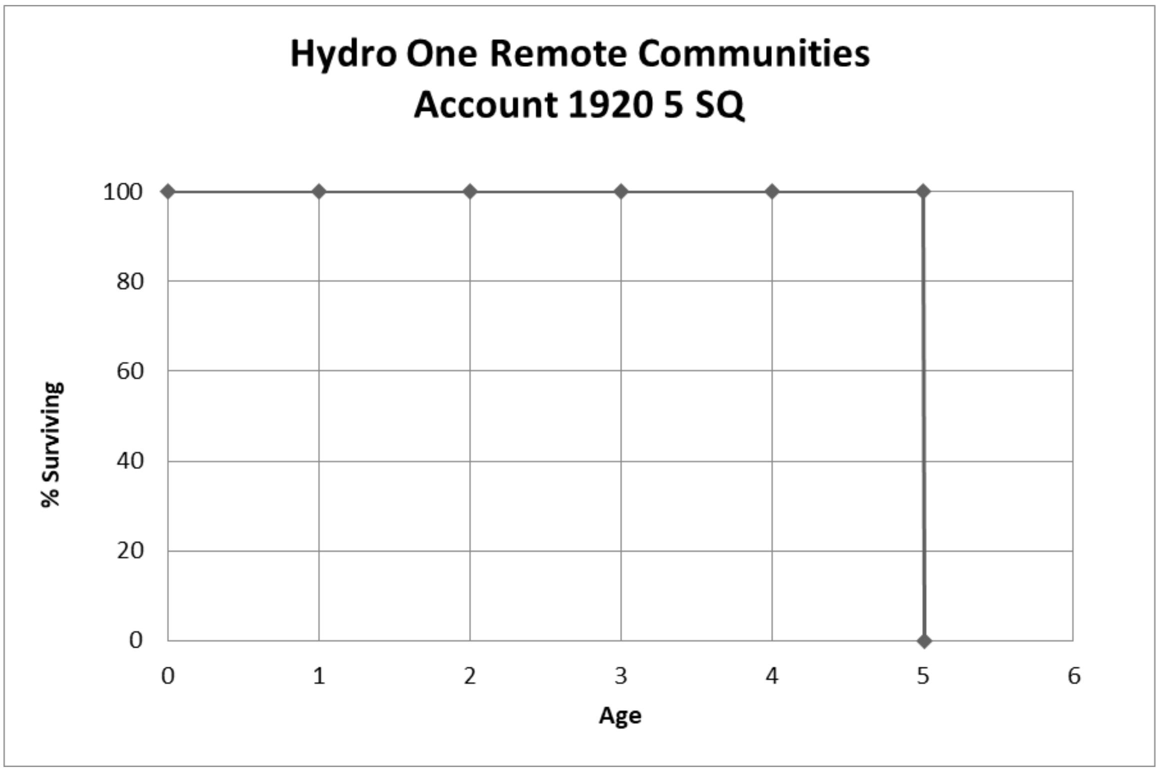
Account 1910 Leasehold Improvements (10 SQ)

This account consists of various leasehold improvements made to leased buildings. The plant balance in this account at December 31, 2021 is $115 thousand. Currently the life of this account is 10 years with an SQ dispersion. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 10-year life with an SQ dispersion.



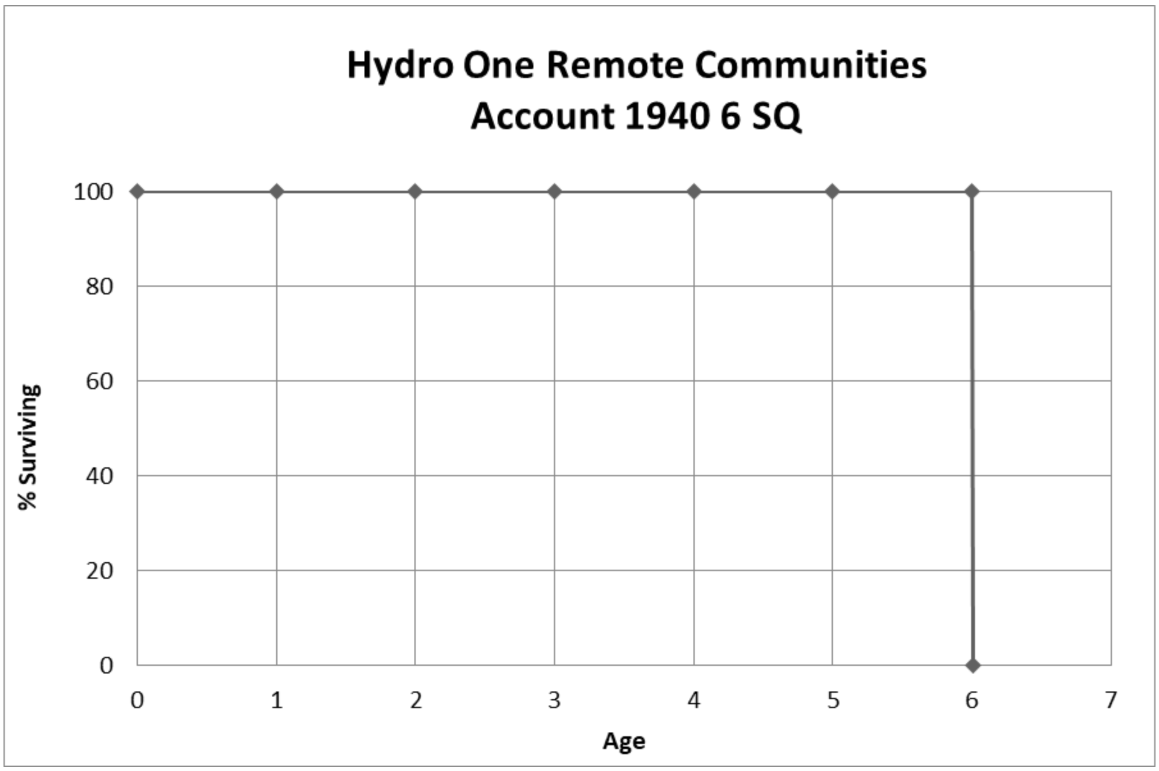
Account 1920 Computer Hardware (5 SQ)

This account consists of computer hardware. Such assets include local area network cable, fiber optic equipment, and electrical devices. The plant balance in this account at December 31, 2021 is $27 thousand. Currently, the amortization life of this account is 5 years. After reviewing plant lives with Company personnel, the determination was that the existing 5-year life is still appropriate for this account. A representative of the life of the account is shown in the curve below, a 5-year life with an SQ dispersion.



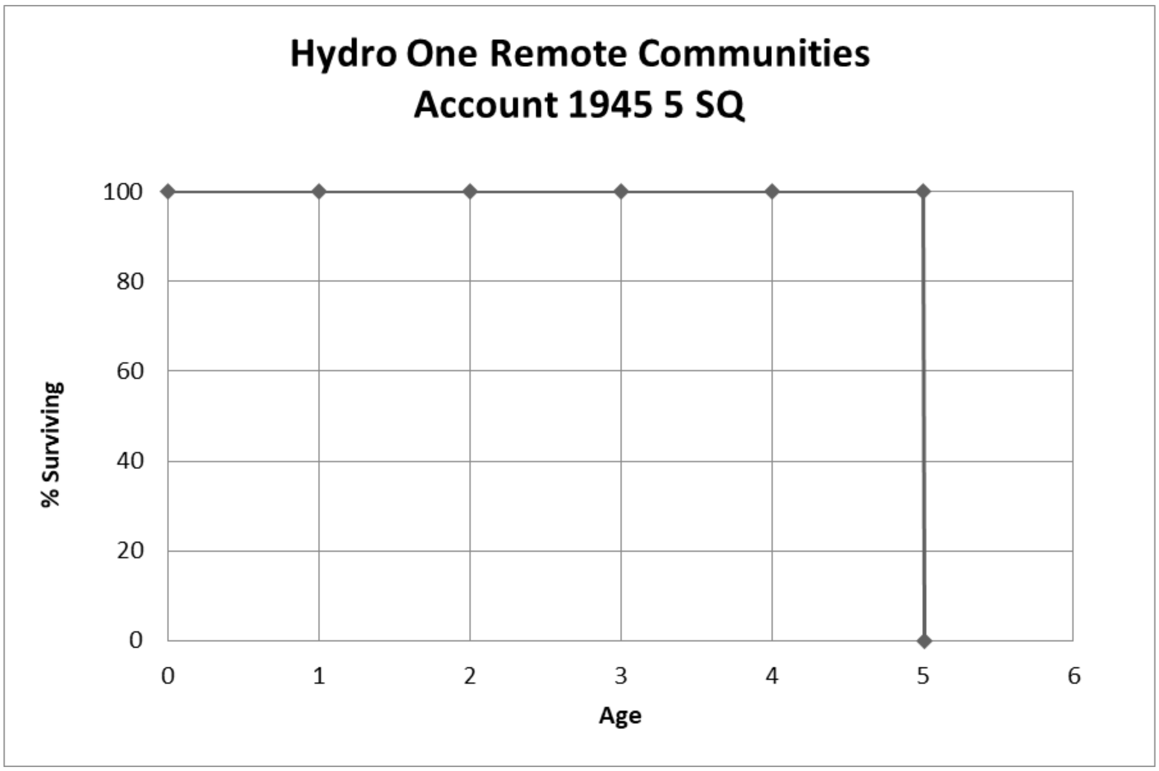
Account 1940 Tools Shop and Garage Equipment (6 SQ)

This account consists of tools, shop, and garage equipment. The plant balance in this account at December 31, 2021 is $104 thousand. Currently the amortization life of this account is 6 years. After reviewing plant lives with Company personnel, the determination was that the existing 6-year life is still appropriate for this account. A representative of the life of the account is shown in the curve below, a 6-year life with an SQ dispersion.



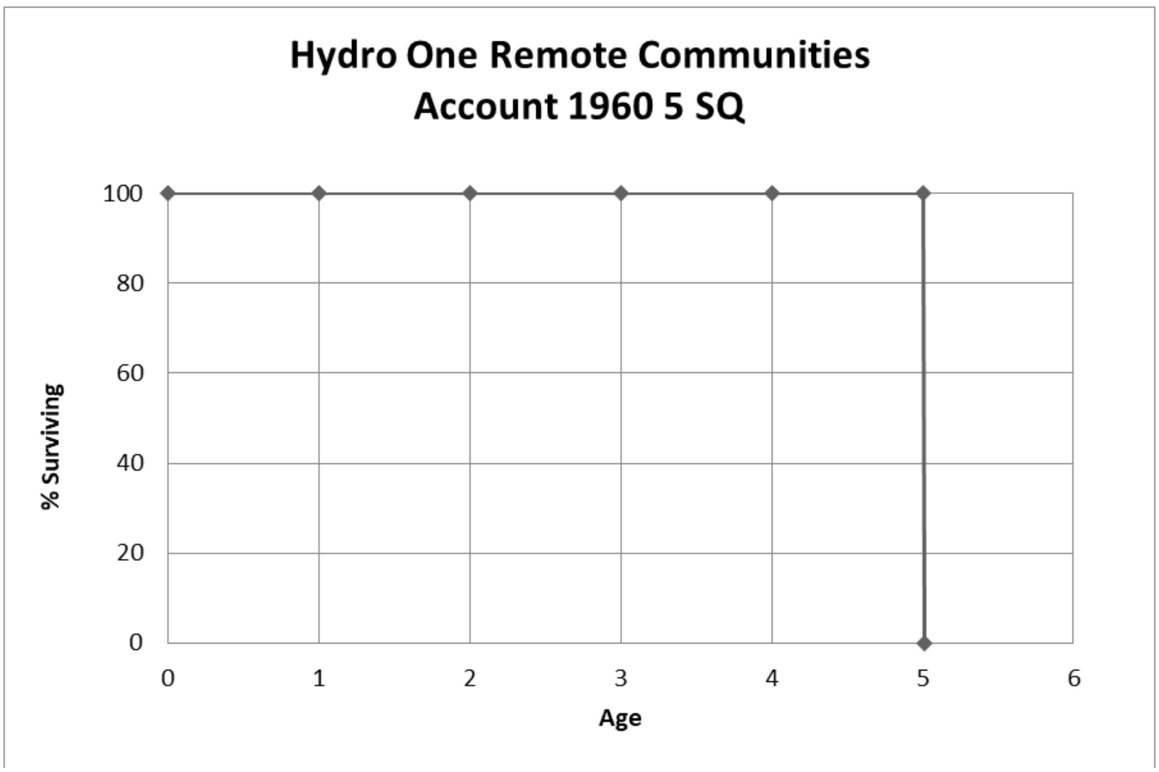
Account 1945 Measurement and Testing Equipment (5 SQ)

This account consists of measurement and testing equipment. Such assets include general system software and various fiber optic equipment. The plant balance in this account at December 31, 2021 is $71 thousand. Currently the amortization life of this account is 5 years. After reviewing plant lives with Company personnel, the determination was that the existing 5-year life is still appropriate for this account. A representative of the life of the account is shown in the curve below, a 5-year life with an SQ dispersion.



Account 1960 Miscellaneous Equipment (5 SQ)

This account consists of miscellaneous equipment. Such assets include general system software and various fiber optic equipment. The plant balance in this account at December 31, 2021 is $402 thousand. Currently, the amortization life of this account is 5 years. After reviewing plant lives with Company personnel, the determination was that the existing 5-year life is still appropriate for this account. A representative of the life of the account is shown in the curve below, a 5-year life with an SQ dispersion.



APPENDIX A

Depreciation Rate Calculations

HYDRO ONE REMOTE COMMUNITIES
COMPARISON OF DEPRECIATION RATES
WITH RESERVE REALLOCATION
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2021

Account	Description	Plant Balance Total at 12/31/2021	Allocated Reserve 12/31/2021	Unaccrued Balance	Remaining Life	Annual Accrual	Annual Accrual Rate
GENERATION							
1620	Buildings and Fixtures	6,476,934.73	2,718,412.20	3,758,522.53	22.08	170,220.28	2.63%
1665	Fuel Holders, Producters and Accessories	8,470,508.70	3,999,747.44	4,470,761.26	13.45	332,444.60	3.92%
1670	Prime Movers	17,920,519.25	7,446,081.49	10,474,437.76	8.88	1,179,041.11	6.58%
1675	Generators	7,984,584.58	3,708,651.45	4,275,933.13	10.06	425,239.16	5.33%
1680	Accessory Electric Equipment	1,754,985.75	1,190,417.97	564,567.78	8.88	63,610.31	3.62%
1685	Miscellaneous Power Plant Equipment	4,530,629.28	1,223,149.78	3,307,479.50	25.16	131,434.85	2.90%
	Subtotal	47,138,162.29	20,286,460.34	26,851,701.95		2,301,990.30	4.88%
DISTRIBUTION							
1806	Improvements to Land	528,582.87	204,130.57	324,452.30	41.87	7,748.61	1.47%
1830	Poles, Towers and Fixtures	4,120,576.94	909,055.08	3,211,521.86	43.82	73,287.97	1.78%
1835	Overhead Conductors and Devices	2,533,743.32	550,970.94	1,982,772.38	51.98	38,146.95	1.51%
1845	Underground Conductors and Devices	292,254.19	145,449.32	146,804.87	21.66	6,778.17	2.32%
1850	Line Transformers	2,544,833.75	886,924.52	1,657,909.23	27.16	61,052.04	2.40%
1860	Meters	1,282,269.88	427,077.57	855,192.31	8.32	102,817.38	8.02%
	Subtotal	11,302,260.95	3,123,608.00	7,323,460.64		289,831.11	2.56%
GENERAL							
Depreciated							
1908	Building and Fixtures	12,367,224.69	3,370,530.94	8,996,693.75	34.89	257,887.41	2.09%
1955	Communication Equipment	20,332.37	20,332.37	-	-	-	0.00%
Amortized							
1920	Computer Hardware	27,336.46	7,208.97	20,127.49	3.68	5,467.29	20.00%
1940	Tools Shop and Garage Equipment	103,747.17	60,168.46	43,578.71	2.52	17,291.20	16.67%
1945	Measurement and Testing Equipment	70,654.00	41,929.00	28,725.00	2.03	14,130.80	20.00%
1960	Miscellaneous Equipment	401,500.17	242,927.80	158,572.37	1.97	80,300.03	20.00%
1910	Leasehold Improvements	115,182.77	103,402.47	11,780.30	1.02	11,518.28	10.00%
		13,105,977.63	3,846,500.00	9,259,477.63		386,595.01	2.95%
	Total	71,546,400.87	27,256,568.34	43,434,640.22		2,978,416.42	

APPENDIX B

Depreciation Expense Comparison

HYDRO ONE REMOTE COMMUNITIES
BU 650
COMPARISON OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2021

Account	Description	Plant Balance Total at 12/31/2021	Current Accrual Rate	Current Accrual Amount	Proposed Accrual Rate	Proposed Accrual Rate	Difference
GENERATION							
1620	Buildings and Fixtures	6,476,934.73	2.78%	180,058.79	2.63%	170,220.28	(9,838.51)
1665	Fuel Holders, Producters and Accessories	8,470,508.70	2.77%	234,633.09	3.92%	332,444.60	97,811.51
1670	Prime Movers	17,920,519.25	6.73%	1,206,050.95	6.58%	1,179,041.11	(27,009.84)
1675	Generators	7,984,584.58	5.45%	435,159.86	5.33%	425,239.16	(9,920.70)
1680	Accessory Electric Equipment	1,754,985.75	5.44%	95,471.22	3.62%	63,610.31	(31,860.92)
1685	Miscellaneous Power Plant Equipment	4,530,629.28	3.89%	176,241.48	2.90%	131,434.85	(44,806.63)
	Total Production	47,138,162.29		2,327,615.39		2,301,990.30	(25,625.08)
DISTRIBUTION							
1806	Improvements to Land	528,582.87	0.97%	5,127.25	1.47%	7,748.61	2,621.36
1830	Poles, Towers and Fixtures	4,120,576.94	1.78%	73,346.27	1.78%	73,287.97	(58.30)
1835	Overhead Conductors and Devices	2,533,743.32	1.94%	49,154.62	1.51%	38,146.95	(11,007.67)
1845	Underground Conductors and Devices	292,254.19	3.03%	8,855.30	2.32%	6,778.17	(2,077.13)
1850	Line Transformers	2,544,833.75	2.41%	61,330.49	2.40%	61,052.04	(278.45)
1860	Meters	1,282,269.88	6.58%	84,373.36	8.02%	102,817.38	18,444.02
	Total Distribution	11,302,260.95		282,187.30		289,831.11	- 7,643.81
GENERAL							
Depreciated							
1908	Building and Fixtures	12,367,224.69	1.96%	242,397.60	2.09%	257,887.41	15,489.80
1955	Communication Equipment	20,332.37	3.38%	-	0.00%	-	-
Amortized				-			
				-			
				-			
1920	Computer Hardware	27,336.46	19.25%	5,262.27	20.00%	5,467.29	205.02
1940	Tools Shop and Garage Equipment	103,747.17	16.67%	17,294.65	16.67%	17,291.20	(3.46)
1945	Measurement and Testing Equipment	70,654.00	17.34%	12,251.40	20.00%	14,130.80	1,879.40
1960	Miscellaneous Equipment	401,500.17	20.00%	80,300.03	20.00%	80,300.03	-
				-			
1910	Leasehold Improvements	115,182.77	0.00%	-	10.00%	11,518.28	11,518.28
	Total General	13,105,977.63		357,505.96		386,595.01	29,089.04
	Total Hydro One Remote	71,546,400.87		2,967,308.65		2,978,416.42	11,107.78

APPENDIX C

Depreciation Parameter Comparison

HYDRO ONE REMOTE COMMUNITIES
CURRENT AND PROPOSED DEPRECIATION PARAMETERS
AT DECEMBER 31, 2021

USofA	USofA Description		Current Life	Current Curve	Current Procedure	Proposed Life	Proposed Curve	Proposed Procedure
GENERATION								
1620	Buildings and Fixtures	6,476,934.73	35	S6	SL-VG-RL	35	S6	SL-BG-RL
1665	Fuel Holders, Producters and Accessories	8,470,508.70	35	S6	SL-VG-RL	23	R2	SL-BG-RL
1670	Prime Movers	17,920,519.25	10	S6	SL-VG-RL	14	L1	SL-BG-RL
1675	Generators	7,984,584.58	16	S6	SL-VG-RL	17	S0.5	SL-BG-RL
1680	Accessory Electric Equipment	1,754,985.75	17	S6	SL-VG-RL	22	R3	SL-BG-RL
1685	Miscellaneous Power Plant Equipment	4,530,629.28	25	S6	SL-VG-RL	33	R2.5	SL-BG-RL
	Subtotal	47,138,162.29						
DISTRIBUTION								
		-	50	S6	SL-VG-RL			SL-BG-RL
1806	Improvements to Land	528,582.87	100	S5	SL-VG-RL	65	R2	SL-BG-RL
1830	Poles, Towers and Fixtures	4,120,576.94	55	S2	SL-VG-RL	55	S2	SL-BG-RL
1835	Overhead Conductors and Devices	2,533,743.32	50	S2	SL-VG-RL	65	R2	SL-BG-RL
1845	Underground Conductors and Devices	292,254.19	30	S3	SL-VG-RL	40	S3	SL-BG-RL
1850	Line Transformers	2,544,833.75	40	R2	SL-VG-RL	40	R2	SL-BG-RL
1860	Meters	1,282,269.88	15	R5	SL-VG-RL	12	L1.5	SL-BG-RL
GENERAL								
Depreciated								
1908	Building and Fixtures	12,367,224.69	50	S4	SL-VG-RL	50	S4	SL-BG-RL
1955	Communication Equipment	20,332.37	7	S6	SL-VG-RL	7	S6	SL-BG-RL
Amortized								
1920	Computer Hardware	27,336.46	5	SQ	Amortize	5	SQ	Amortize
1940	Tools Shop and Garage Equipment	103,747.17	6	SQ	Amortize	6	SQ	Amortize
1945	Measurement and Testing Equipment	70,654.00	5	SQ	Amortize	5	SQ	Amortize
1960	Miscellaneous Equipment	401,500.17	5	SQ	Amortize	5	SQ	Amortize
1910	Leasehold Improvements	115,182.77			Amortize	10	SQ	Amortize

APPENDIX D

Summary of Depreciation Book Reserve,

Reallocated Depreciation Reserve,

and Theoretical Depreciation Reserve

HYDRO ONE REMOTE COMMUNITIES
COMPARISON OF BOOK AND REALLOCATED DEPRECIATION RESERVE
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2021

Account	Description	Plant Balance Total at 12/31/2021	Allocated Reserve 12/31/2021	Account	Description	Plant Adjustment	Adjusted Plant Balance 12/31/2021	Per Book Reserve 12/31/2021	Difference
GENERATION									
1620	Buildings and Fixtures	6,476,934.73	2,718,412.20	1620	Buildings and Fixtures		6,476,934.73	1,983,305.47	735,106.73
1665	Fuel Holders, Producters and Accessories	8,470,508.70	3,999,747.44	1665	Fuel Holders, Producers and Accessories		8,470,508.70	1,820,474.03	2,179,273.41
1670	Prime Movers	17,920,519.25	7,446,081.49	1670	Prime Movers		17,920,519.25	11,243,622.78	(3,797,541.29)
1675	Generators	7,984,584.58	3,708,651.45	1675	Generators		7,984,584.58	3,069,525.22	639,126.23
1680	Accessory Electric Equipment	1,754,985.75	1,190,417.97	1680	Accessory Electric Equipment		1,754,985.75	748,001.26	442,416.71
1685	Miscellaneous Power Plant Equipment	4,530,629.28	1,223,149.78	1685	Miscellaneous Power Plant Equipment		4,530,629.28	1,353,277.22	(130,127.44)
140900	Maj Rollup Acc Dep Reserve							240,315.64	(240,315.64)
140940	Acc Dep Contra for Group							(172,061.28)	172,061.28
		47,138,162.29	20,286,460.34				47,138,162.29	20,286,460.34	(0.00)
DISTRIBUTION						-			
1805	Land	-		1805	Land - Depreciable	(294,456.43)	294,456.43	119,897.58	(119,897.58)
1806	Improvements to Land	528,582.87	204,130.57	1806	Land Rights	294,456.43	234,126.44	81,074.08	123,056.49
1830	Poles, Towers and Fixtures	4,120,576.94	909,055.08	1830	Poles, Towers and Fixtures	-	4,120,576.94	761,569.40	147,485.68
1835	Overhead Conductors and Devices	2,533,743.32	550,970.94	1835	Overhead Conductors and Devices	-	2,533,743.32	666,067.16	(115,096.22)
1845	Underground Conductors and Devices	292,254.19	145,449.32	1845	Underground Conductors and Devices	-	292,254.19	183,137.15	(37,687.83)
1850	Line Transformers	2,544,833.75	886,924.52	1850	Line Transformers	-	2,544,833.75	933,275.70	(46,351.18)
1860	Meters	1,282,269.88	427,077.57	1860	Meters	-	1,282,269.88	378,586.93	48,490.64
		11,302,260.95	3,123,608.00				11,302,260.95	3,123,608.00	(0.00)
GENERAL									
Depreciated									
1908	Building and Fixtures	12,367,224.69	3,370,530.94	1908	Buildings and Fixtures		12,367,224.69	3,341,550.06	28,980.88
1955	Communication Equipment	20,332.37	20,332.37	1955	Communication Equipment		20,332.37	32,243.80	(11,911.43)
Amortized									-
									-
1920	Computer Hardware	27,336.46	7,208.97	1920	Computer Equipment - Hardware		27,336.46	7,067.26	141.71
1940	Tools Shop and Garage Equipment	103,747.17	60,168.46	1940	Tools Shop and Garage Equipment		103,747.17	60,168.46	(0.00)
1945	Measurement and Testing Equipment	70,654.00	41,929.00	1945	Measurement and Testing Equipment		70,654.00	41,929.00	-
1960	Miscellaneous Equipment	401,500.17	242,927.80	1960	Miscellaneous Equipment		401,500.17	244,237.48	(1,309.68)
									-
									-
1910	Leasehold Improvements	115,182.77	103,402.47	1910	Leasehold Improvements		115,182.77	119,303.94	(15,901.47)
	Subtotal	13,105,977.63	3,846,500.00		Subtotal		13,105,977.63	3,846,500.00	0.00
	Total	71,546,400.87	27,256,568.34				71,546,400.87	27,256,568.34	(0.00)
				Excluded from Study					
				1615D	Land - Depreciable	Deer Lake Hydro	407,800.00	407,800.00	
				1620D	Buildings and Fixtures	Deer Lake Hydro	527,063.40	527,063.40	

HYDRO ONE REMOTE COMMUNITIES
COMPARISON OF BOOK AND REALLOCATED DEPRECIATION RESERVE
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2021

Account	Description	Plant Balance Total at 12/31/2021	Allocated Reserve 12/31/2021

Account	Description	Plant Adjustment	Adjusted Plant Balance 12/31/2021	Per Book Reserve 12/31/2021	Difference
1650D	Reservoirs, Dams, and Waterways	Deer Lake Hydro	670,777.72	670,777.72	
1675D	Generators	Deer Lake Hydro	1,375,308.29	1,307,733.30	
1685D	Miscellaneous Power Plant Equipment	Deer Lake Hydro	1,399,523.95	1,399,523.95	

APPENDIX E

Summary of Projection Lives by Business Unit

Hydro One Remote BU 650
Asset Category Summary
At December 31, 2021

Description	Current P Life	Current P Life	Proposed P life		Plant
1620 Buidlings and Fixtures					
(blank)				35	157,604.80
GENX-FSL -YD FACILITIES		35		35	204,150.55
GENX-FSL -LANDSCAPING		35		35	235,889.88
GENX-FSL -OTHER SITE IMPR		50		50	395,302.30
GENX-FSL REM- BLDG&STR		35		35	5,483,987.20
Total	35-S6		35 S6		6,476,934.73
1665 Fuel Holders, Producers and Acessories					
(blank)					762,065.12
GENX -FSL REM-FUEL HANDLNG		35		23	7,708,443.58
Total	35-S6		23 R2		8,470,508.70
1670 Prime Movers					
(blank)					896,502.02
GENX -FSL REM- DIESEL ENG		10		14	17,024,017.23
Total	10-S6		14 L1		17,920,519.25
1675 Generators					
(blank)					330,631.57
GENX- HYD REM - TURBINES		50		45	814,818.63
GENX-FSL REM ALT & AUX GEN		15		15	6,839,134.38
Total	16 S6	18	17 S0.5		7,984,584.58
1680 Accessory Electric Equipment					
GENX-FSL REM-WND&SOL GEN		20		25	349,208.51
GENX -FSL REM-STN TRANSF		20		20	497,322.53
GENX - FSL -ELE AUX SYST/CAB		15		20	908,454.71
Total	17 S6		22 R3		1,754,985.75
1685 Miscellaneous Power Plant Equipment					
(blank)				33	612,356.60
GENX-FSL REM FIRE PROT SYS		35		33	647,112.02
GENX-FSL -COMMON SERV SYS		35		33	1,202,014.44
GENX-FSL -INSTR&CNTRL EQU		15			2,069,146.22
Total	25 S6		33 R2.5		4,530,629.28
1806 Land Rights				65	294,456.43
RURAL INTL CLRING & OVRBLDG				65	234,126.44
Total	100-S6		65-R2		528,582.87

Hydro One Remote BU 650
Asset Category Summary
At December 31, 2021

Description	Current P Life	Current P Life	Proposed P life	Plant
1830 Poles Towers and Fixtures				
(blank)				516,823.48
RURAL1995 YE ADJ STRM DAMAG		55	55	684.89
RURALSUPPORTS-WOOD,CONCRET		55	55	3,598,559.31
STEEL POLES SUPPORT		75	75	4,509.26
Total	55-S2			4,120,576.94
			55 S2	
1835 Overhead Conducotrs and Devices				
(blank)				58,783.66
RURAL CONDUCTOR PRIM&SEC OVERH		50	65	1,907,538.56
RURAL INSTALSECTNLZR&RCLSR SW		45	60	1,681.44
RURAL OIL SECTNLZER&RECLSR SW		40	55	72,058.02
RURAL SWITCHES/LOAD INTERPTR		40	55	488,403.64
RURAL VOLTAGE REGULATORS		40	55	5,278.00
Total	50-S2		65 R2	2,533,743.32
1845 Underground Conductors and Devixes				
RURAL U/GRD FUSE HOUSING		30	40	2,834.00
RURAL U/GRD CONDR SEC SERV		30	40	19,828.96
RURAL U/GRD CONDUCTOR-PRIME		30	40	85,869.95
RURAL CONDCTR SUBMARINE CBL		30	40	183,721.28
Total	30 S3		40 S3	292,254.19
1850 Line Transformers				
(blank)				105,927.96
POLE TOP TRFS >200&<=300 KVA		40	40	68,984.08
POLE TOP TRFS >300&<=500 KVA		40	40	16,935.00
RURAL OH TRFMR >75&<=100 KVA		40	40	15,441.67
RURAL OH TRFMRS >25&<=50 KVA		40	40	701,804.09
RURAL OH TRFMRS>50&<=75 KVA		40	40	140,071.53
RURAL OH TRFRMRS <=25 KVA		40	40	1,364,469.24
RURAL-U/GRD TRSF 301-500KVA		40	40	20,685.27
RURAL-U/GRD TRSF 0-50KVA		40	40	110,514.91
Total	40- R2		40 R2	2,544,833.75
1860 Meters				
(blank)				117,690.54
INSTALL-METERS POLYPHASE		15	12	90.73
INSTALL-W/HR&DMD M S PH		15	12	919,466.95
METERING POLYPHASE		15	12	4.83

Hydro One Remote BU 650
Asset Category Summary
At December 31, 2021

Description	Current P Life	Current P Life	Proposed P life		Plant
METERS-WATTHOUR,SINGLE PH		15		12	70,526.01
PRIM M UNIT>=75(INST ONLY)		15		12	174,490.82
Total	15-R5		12 L2.5		1,282,269.88
1908 Buildings and Fixtures					
(blank)					398,483.56
GENRL -ADM & SERV_AUX EQ BLD		50		50	175,624.84
GENRL- ADM & SERV-DISTN SYS		50		50	1,383.89
GENRL -ADM & SERV-FENCE,GATE		50		50	384,054.06
GENRL -COMM - BUILDINGS		50		50	6,279.45
GENRL-ADM & SERV-BLD FRAME		50		50	3,659,962.91
GENRL-ADM&SERV_BLD FRAME&MTL		50		50	7,685,801.11
GENRL-ADM&SERV-LANDSCAPING				50	55,634.87
Total	50-S4		50 S4		12,367,224.69
1910 Leasehold Improvements					
GENRL -ADM & SERV-BLDGS-LEASED					115,182.77
Total					115,182.77
1920 Computer Hardware Minor					
MFA - 5YR SL(DEF)	5 -SQ		5 SQ		27,336.46
Total					27,336.46
1940 Tools Shop and Garage Equipment					
MFA - 6 YR SL(DEF)					103,747.17
Total	6-SQ		6 SQ		103,747.17
1945 Measurement and Testing Equipment					
MFA - 5YR SL(DEF)	5-SQ		5 SQ		70,654.00
Total					70,654.00
1955 Communication Equipment					
GENRL-ADM & SERV -TELCM WIRE					20,332.37
Total	7-S6		7 S6		20,332.37
1960 Miscellaneous Equipment					
MFA - 5YR SL(DEF)					401,500.17
Total	5-SQ		5 SQ		401,500.17

APPENDIX F

Alliance Consulting Group –

Background and Qualifications

Company Profile

Alliance Consulting Group is an international consulting firm formed in 2004 by Dane Watson. In addition to the partner, Alliance also has three full-time Senior Consultants, Dr. Karen Ponder, Ms. Rhonda Watts, and Ms. Rebecca Richards, as well as other support staff. Alliance is dedicated to providing quality consulting and expert services to the utility industry. Our professionals have more than 120 years of combined experience around the utility industry, and we have been employed in the industry as utility employees and consultants.

The Alliance Consulting Group has performed nearly 300 depreciation studies for electric, gas, steam, water, wastewater, cable, and communications utilities across the country and Canada since its founding by Mr. Watson in 2004. These utilities encompass regulated, non-regulated, municipal and federal agencies. The studies were provided in a timely manner with thorough analysis.

Personnel

People

Dane Watson, project Manager

The project manager will be Dane Watson of Alliance. He was previously employed as a Property Accounting Services Manager for TXU and has twenty years of experience at a Fortune 100 utility in property accounting, depreciation and valuation. He has managed fixed asset accounting for regulated entities and non-regulated entities. He has an industry-wide reputation with significant experience as an expert witness in depreciation, valuation and rate base areas and has provided testimony and support in many state regulatory commission dockets. Mr. Watson has conducted depreciation studies for a variety of assets for both regulated and non-regulated companies. He has held a number of national industry roles related to depreciation and property accounting including twice chairing the Plant Accounting and Valuation Committee of the Edison Electric Institute. He has attended all the classes offered by the Depreciation Programs, Inc. (DPI) and continues to re-fresh his training by teaching various depreciation related seminars across the country. He developed the training materials for the Intermediate and Advanced Training sessions of the Society for Depreciation Professionals and teaches a number of courses. He twice served as general editor of the industry publication "Introduction to Depreciation and Net Salvage of Public Utility Plant and Plant of Other Industries", is contributing editor of other industry publications and is a frequent speaker at conferences on depreciation related issues. Mr. Watson led the industry adoption of SFAS 143 and was industry panelist before FERC (FERC Docket 02-0700) testifying on their implementation of SFAS 143. He also served as project lead (functional) in the development of both automated regulated group depreciation and fixed asset systems and item based fixed asset and depreciation systems while at TXU. Mr. Watson is a Licensed Professional Engineer in the State of Texas (PE) and a Certified Depreciation Professional (CDP).

KAREN PONDER, SENIOR CONSULTANT

Dr. Karen Ponder is a Senior Consultant at Alliance with over forty years of experience in utility financial matters. Dr. Ponder has a doctorate degree in engineering valuation from Iowa State University where her dissertation was entitled, "Some Aspects of Statistically Modeling the Simulated Plant Record Method." She is considered a subject matter expert in depreciation and capital recovery in the utility industry and has performed studies for regulated and non-regulated entities involving property of various types. Dr. Ponder has conducted statistical analysis of life and net salvage components and incorporated knowledge of equipment failure, new technological trends, and company practices to develop life and net salvage estimates. She has provided support during rate case litigation including study write-up, testimony, and responses to interrogatories. She was an instructor for many years at Depreciation Programs, Inc. in Kalamazoo, Michigan and serves as a faculty member for the Society of Depreciation Professional's Annual Training courses. Dr. Ponder is a Certified Depreciation Professional. (CDP).

RHONDA WATTS, SENIOR CONSULTANT

Rhonda Watts is a Senior Consultant at Alliance who participates in the various activities related to the completion of the depreciation study and provides Expert Witness testimony if needed. Rhonda has over thirty years of experience in utility accounting, depreciation and regulatory matters. She is considered a subject matter expert in depreciation and capital recovery in the utility industry and has performed studies for regulated entities involving property of electric, gas, water and wastewater and communication utilities. She has conducted statistical analysis of life and net salvage components and incorporated knowledge of equipment failure, new technological trends, and company practices to develop life and net salvage estimates. She has provided support during rate case litigation including study write-up, testimony, and responses to interrogatories. Rhonda has also testified before three state regulatory bodies.

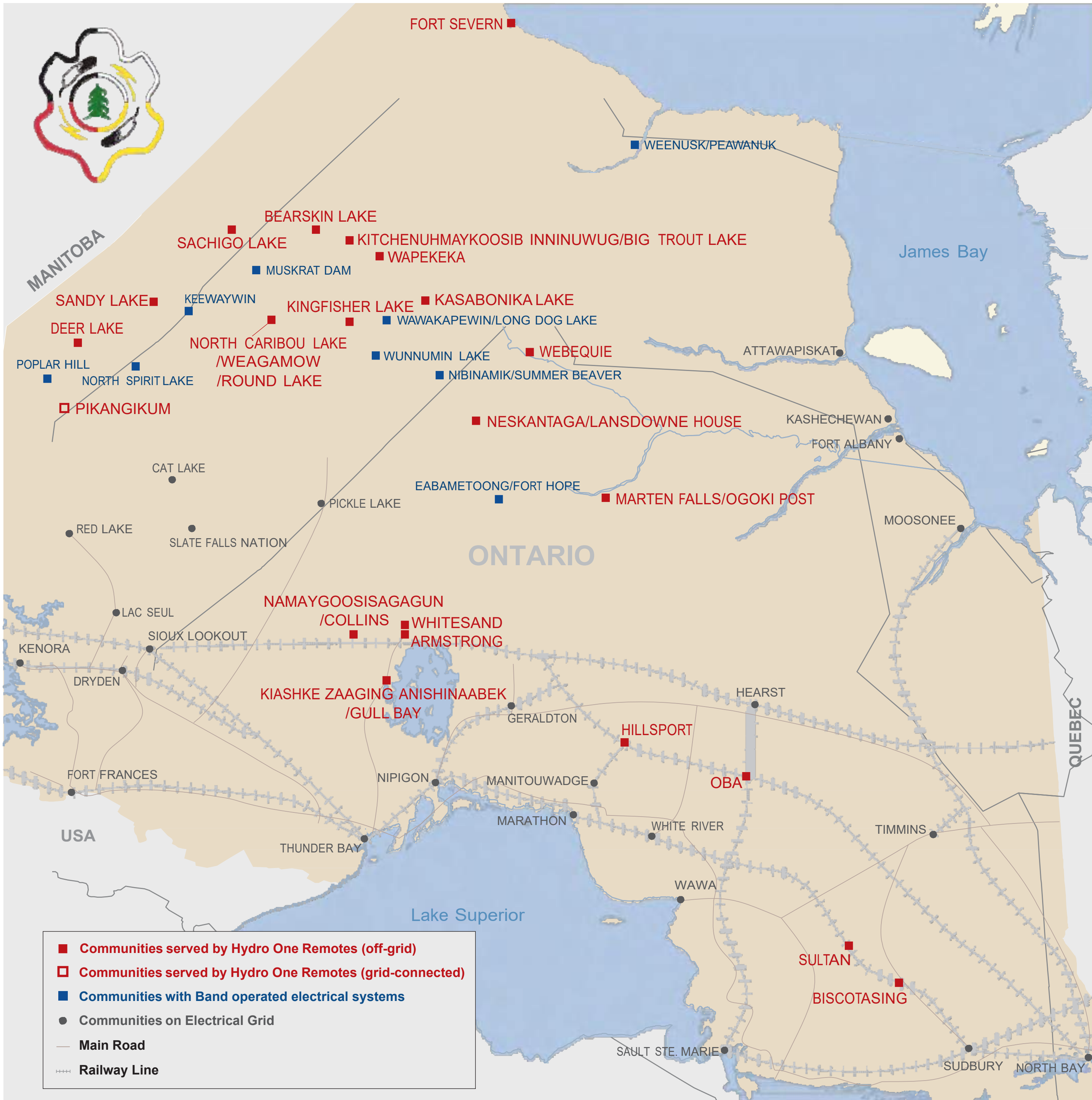
REBECCA RICHARDS, SENIOR CONSULTANT

Rebecca Richards is a Senior Consultant at Alliance and a Certified Depreciation Professional (CDP). She was previously employed as a Team Lead of Property Accounting at We Energies and has nine years of experience at a Fortune 500 company in utility property accounting, depreciation and areas of corporate finance. She has a vast working knowledge of fixed asset and finance systems including SAP, UI, and PowerPlan. Rebecca has managed fixed asset accounting for both regulated and non-regulated entities. She has coordinated depreciation studies for all types of utilities including electric, gas, water, and steam heating.

APPENDIX G

Hydro One Remote Communities

Service Territory Map



22 COMMUNITIES
17 First Nations • 14 air access only

4,200 CUSTOMERS

15,000+ PEOPLE ARE PROVIDED POWER

2 MINI HYDRO STATIONS

20 DISTRIBUTION SYSTEMS

56 DIESEL GENERATORS

ENVIRONMENTAL LEADER: ISO 14001 STANDARD

19M L OF FUEL USED EACH YEAR

17 CUSTOMER-OWNED RENEWABLE PROJECTS IN SERVICE

INTEREST CAPITALIZED AND CAPITALIZATION OF OVERHEADS

1.0 INTEREST CAPITALIZED

Consistent with the Board's Decision in EB-2008-0408, effective January 1, 2012, no allowance for funds used during construction (AFUDC) rate is specified by the Board for use by Hydro One. Hydro One was directed to base its interest capitalization rate on its embedded cost of debt used to finance capital expenditures. This is consistent with Hydro One's adoption of United States generally accepted accounting principles (US GAAP) per the Board's Decision in EB-2011-0399 and US GAAP requirements for determination of interest capitalized. The rates used in calculating capitalized interest for the bridge and test years represent the effective rate of Remotes' forecast average debt portfolio during the year.

The interest capitalization rate/AFUDC rate for historical, bridge and test years are shown in Table 1:

Table 1 - Interest Capitalization Rates

Year		Interest Capitalized / AFUDC	
		Rate (%)	(in thousands, $)
	Board Approved 2018	4.4	117
Historical	**2018**	5.3	126
	2019	4.9	124
	2020	4.8	173
	2021	4.9	219
Forecast	**2022**	4.2	99
	2023	4.1	122

2.0 CAPITALIZATION OF OVERHEADS

Remotes capitalizes costs that are directly attributable to the acquisition and construction of capital projects. Remotes also capitalizes certain overhead and indirect costs that are supporting capital projects. With the Board's approval of US GAAP as the basis for regulatory accounting and rate setting for Remotes and consistent with the Board's Decision in EB-2012-0137, Remotes continues to capitalize attributable overhead costs consistent with US GAAP.

The Remotes' overhead capitalization rate is a calculated percentage representing the amount of Common Corporate Functions and Services (CCFS) overhead costs that are required to support capital projects in a given year. Specifically, this rate reflects the total CCFS amounts to be capitalized as a percentage of total capital expenditures. Due to the lumpiness of Remotes' capital program, CCFS amounts to be capitalized are determined based a 3-year average of direct capital expenditures as a percentage of the total capital and OM&A work program. The overhead capitalization rate for 2023 is 4.9%. Networks in 2007 began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs.

The following table shows capitalized overheads, and the related overhead capitalization rates for the historical, bridge and test years.

Table 2 - Overhead Capitalization - Historical, Bridge and Test Years (*in thousands, $*)

	Board Approved 2018	Historical				Bridge	Test
		2018	2019	2020	2021	2022	2023
Total capitalized overheads	448	559	544	588	596	718	723
Capitalized overhead rate (%)	4.9	4.8	4.8	4.7	4.8	4.9	4.9

Remotes' capitalization policy is primarily consistent with the capitalization policy used by Networks, which has been filed in the EB-2021-0110 proceeding in the interrogatory response to C-SEC-179.[1]

[1] EB-2021-0110, HONI IRRs to SEC (pt4 IRR), Attachment 1 of C-SEC-179, November 29, 2021

This page has been left blank intentionally.

LOAD FORECAST AND METHODOLOGY

1.0 INTRODUCTION

Remotes' load forecast underpins its revenues from customers and its fuel forecast. Remotes has two broad categories of customers, Standard A or government customers whose rates have historically been set above cost, and those Residential and General Service customers who benefit from Rural and Remote Rate Protection. These two categories are set out in O. Reg. 442/01, the regulation under the *Ontario Energy Board Act, 1998,* that establishes the rules for Rural and Remote Rate Protection (RRRP). Most of Remotes' customers pay rates that are subsidized by RRRP and are set well below the per kWh cost to serve from diesel fuel.

Remotes does not have any load transfer agreements with other utilities.

2.0 LOAD FORECAST

Remotes tracks detailed monthly data on customer numbers and kWh usage by community and by class. This historical data provides the baseline for forecasting revenue usage / kWh sold. Adjustments are made to this baseline data for future years based on average historical growth in usage and historical annual customer changes.

Historical trends include the impact of Remotes' Conservation and Demand Management (CDM) program and other conservation efforts undertaken directly by the communities through funding from the federal government and the IESO. CDM program results are not included in the forecast. CDM program results have varied considerably since the program's inception based on the participation of local customers and Band Councils in conservation efforts.

Three additional sources of information are also used in compiling this forecast: Band Councils, ISC, and employees. Each year, Remotes solicits information from Band Councils on planned construction projects. Remotes also holds an annual planning meeting with ISC for information on program activities that could affect load. Finally, field employees share information about pending connections, when these connections are material, such as the construction of a housing subdivision, schools, or water treatment plants. Employees are also canvassed for information on communities where generation capacity has reached its limits, forcing a constraint on future near-term peak load growth. Data and equations used to determine customer/connections and load forecasts is set out in Exhibit C, Tab 1, Schedule 2.

This analysis of forecast load is not checked against external forecasts as these forecasts are not appropriate to use to forecast load in Remotes' service territory. Most of the communities Remotes serves are northern First Nation reserves, which are not specifically addressed in external reports such as the CMHC Outlook. Furthermore, key market indicators for most external reports such as housing growth generally do not apply within remote First Nation reserves. Similarly, an upturn in the overall Canadian or Ontario economy has not historically resulted in a similar increase in economic activity within these communities. In the case of the link between population growth and increases in housing units, for example, increases in population within the communities do not tie directly to an increase in the number of houses.

A February 2011 audit report that evaluated ISC's on-reserve housing support found, for example, that "while housing stock has increased steadily since 1996 through construction of new units and repairs to damaged units, the results have not kept pace with housing needs."[1] Moreover, that same report found that even the rate of new housing construction on reserves does not directly correlate to an increased number of housing units because "the housing build on reserve is not lasting as long as it should and needs replacing sooner than can be afforded."

---

[1] Evaluation of INAC's On-Reserve Housing Support, February 2011, Chapter 5. Available on AANDC's website: http://www.aadnc-aandc.gc.ca/aiarch/arp/aev/pubs/ev/orhs/orhs-eng.asp#exe (this is archived information).

The following table summarizes the factors that influence the load forecast in the Remotes service territory:

Table 1 - Factors that Influence the Load Forecast in the Remotes Service Territory

• Existing customer counts, and historical energy use unique to customer class and community
• Planned construction projects (information gathered from Band Councils, ISC and employees)
• Pending connections, in particular material connections such as the construction of a housing subdivision, schools or water treatment plants
• Circumstances where generation capacity has reached its limits, forcing a constraint on future near-term peak growth
• Program activities in communities including but not limited to CDM program and other conservation efforts undertaken directly by communities (included in historical trends but not in the forecast of load due to considerable variances)
• New IPAs added to Remotes' service territory

Remotes does not normalize its load forecast for weather for three reasons: (i) its communities are very small and are scattered within a wide territory; (ii) reliable historical weather station data is not available for any communities within Remotes' service territory (the closest reliable data is for Thunder Bay); and (iii) because Remotes is operated as a break-even business, it does not stand to profit as a result of forecasting errors.

Once the load forecast is completed, revenues are calculated based on the rate class usage characteristics and the applicable rate schedules.

Table 2 below shows the 2023 load forecast by category and Table 3 below shows the 2022 and 2023 load forecast by customer class. The effective number of customers in the tables below reflect the year-end customer counts. Remotes does not have customers who are demand billed.

Table 2 - 2023 Load Forecast Summary Table

Load Forecast Summary	
Effective # of Standard A Customers	676
Total Standard A MWhs	19,398
Effective # of Non-Standard A Customers	4,515
Total Non Standard A MWhs	78,027
Total Effective # of Customers	5,191
Total MWhs	**97,425**

Table 3 - Load Forecast by Customer Class

	2022			2023		
	Effective # of Customers	**Average kWh's/ Customer**	**Total MWh's**	**Effective # of Customers**	**Average kWh's/ Customer**	**Total MWh's**
Non Std A - Residential	3,372	16,463	55,513	3,938	15,792	62,191
Non Std A - Seasonal	142	2,678	380	142	2,594	368
Non Std A - General 1-Phase	317	23,867	7,566	359	22,620	8,120
Non Std A - General 3-Phase	60	107,374	6,443	68	104,479	7,105
Street Lighting	8	30,542	244	8	30,366	243
Std A - Residential-Road	4	6,226	25	4	6,321	25
Std A - Residential-Air	133	13,053	1,736	70	17,213	1,205
Std A - General-Road	20	42,441	849	20	38,189	764
Std A - General-Air	244	41,697	10,174	112	67,605	7,572
Std A - Grid Connected	151	26,703	4,032	470	20,920	9,832
Total	**4,451**		**86,962**	**5,191**		**97,425**

The increase of 2023 over 2022 load forecast due to load growth, new IPAs connecting to the grid entering Remotes' service territory and increased customer count.

Tables 4 and 5 below show a summary view of the 2023 load forecast by Non-Standard A and Standard A customer class.

Table 4 - 2023 Non-Standard A Load Forecast by Customer Class

	Residential	Seasonal	GS 1 Phase	GS 3 Phase	Streetlight	Total
Effective # of Customers	3,938	142	359	68	8	4,515
Average kWhs/Customer	15,792	2,594	22,620	104,479	30,366	
Total MWhs	62,191	368	8,120	7,105	243	78,027

Table 5 - 2023 Standard A Load Forecast by Customer Class

	Residential Road Rail	Residential Air Access	GS Road Rail	GS Air Access	Grid Connected	Total
Effective # of Customers	4	70	20	112	470	676
Average kWhs/Customer	6,321	17,213	38,189	67,605	20,920	
Total MWhs	**25**	**1,205**	**764**	**7,572**	**9,832**	**19,398**

3.0 VARIANCE ANALYSIS OF CUSTOMER COUNTS (2018-2023)

Table 6 - Customer Count

Year	Customer Count at Year End	Year over Year	
		Customer Count	%
2017	3,598		
2018	3,669	71	2.0%
2019	4,236	567	15.5%
2020	4,279	43	1.0%
2021	4,368	89	2.1%
2022	4,451	83	1.9%
2023	5,191	740	16.6%

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- Increase in customer count, addition of 6 new IPAs and Cat Lake joining Remotes' service territory and increased load growth.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- Increase in customer count, addition of 6 new IPAs and Cat Lake joining Remotes' service territory and increased load growth.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- Increase in customer count, balance of new IPAs and Cat Lake joining Remotes' service territory and increased load growth.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- Increase in load growth and customer count.

2018 ACTUALS VS 2018 OEB-APPROVED

- Immaterial change.

YEAR OVER YEAR

The 2019 variance observed the table is due to the addition of the Pikangikum community. The 2023 variance is due to the addition of 3 new IPAs and Cat Lake joining Remotes territory.

4.0 VARIANCE ANALYSIS OF CONSUMPTION (2018-2023)

Table 7 - Consumption

Year	MWh	Year over Year	
		MWh	%
2017	62,492		
2018	66,379	3,887	6.2%
2019	72,056	5,677	8.6%
2020	82,176	10,120	14.0%
2021	82,208	32	0.0%
2022	86,962	4,754	5.8%
2023	97,425	10,463	12.0%

- 2019 variance is due to the addition of Pikangikum in September 2019.
- 2020 is due to load growth, increased customer count, and Pikangikum.
- 2022 variance is due to the addition of 3 new IPAs, load growth, and customer count.
- 2023 variance is due to the addition of the balance of the IPAs and Cat Lake joining Remotes territory.

Exhibit C, Tab 1, Schedule 3 sets out a variance analysis of 2017 to March 2022 load forecast to actual.

This page has been left blank intentionally.

STATISTICAL DATA FOR 2023 LOAD FORECAST

This exhibit has been filed separately in MS Excel format.

LOAD FORECAST VS ACTUAL

This exhibit has been filed separately in MS Excel format.

COST OF SERVICE SUMMARY, COST DRIVERS AND SUMMARY OF OM&A EXPENDITURES

1.0 INTRODUCTION

This exhibit provides an overview of Remotes' Operations, Maintenance and Administration (OM&A) expenditures over the 2018 to 2023 period, including the 2018 to 2021 historical period, the 2022 bridge year[1], and the 2023 test year.

Remotes' forecast cost of service has been developed consistent with its corporate objectives. The Company's planning process is described in detail in the DSP and in Exhibit A, Tab 7, Schedule 2.

Remotes is seeking approval of a total 2023 test year OM&A of $126,568k. This 2023 budget amount, when normalized to exclude the Watay Transmission Connection Cost and Cost of Power also associated with the Watay Transmission Project, represents approximately an 11% increase relative to the last OEB-approved 2018 amount of $47,243k.

Table 1 - 2023 OM&A Comparison

	Thousands $	2023
A	2023 Test Year OM&A	$126,568
B	Less: Watay Transmission Connection Cost	$66,000
C	Less: Cost of Power	$8,162
D=A-B-C	Normalized OM&A	$52,406
E	2018 OEB-Approved OM&A	$47,243
F=D-E	Variance	$5,163
G=F/E	% Variance	11%

[1] 2022 is provided on a forecast basis

The requested OM&A expenditures result from a business planning and work prioritization process that reflects risk-based decision making to ensure that appropriate, environmentally responsible and cost-effective solutions are in place. A rate of 1.87% is assumed for annual inflation and cost escalators to establish the OM&A budget. The business planning process and economic considerations are further described in Exhibit A, Tab 7, Schedule 2.

The proposed OM&A programs are required to meet public and employee safety objectives, to comply with regulatory requirements and government direction, to protect the environment, to maintain service quality and reliability at targeted performance levels, and to ensure public confidence as stewards of the assets entrusted to Remotes.

Remotes' OM&A budget is grouped by investment categories: Generation, Fuel, Distribution, Other Power Supply Expenses, Customer Care, Community Relations, Shared Services and Other Administrative Costs, External Costs and Property Taxes.

Table 2 provides a summary of Remotes' OM&A expenditures for the historical, bridge and test years.

Table 2 - Summary of OM&A Budget *(in thousands $)*

Description	Board Approved	Historical (Actual)				Bridge	Test
	2018	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Generation	15,222	14,080	14,546	14,234	14,290	14,133	12,574
Fuel	25,900	29,406	30,251	29,166	34,481	41,200	30,365
Distribution	2,014	1,758	2,078	3,075	2,590	2,990	3,745
Customer Care	2,151	1,812	1,982	1,875	1,409	2,218	2,383
Community Relations	496	157	703	459	407	675	682
Watay Transmission Connection Cost	-	-	-	-	-	21,285	66,000
Cost of Power	-	14	1,463	1,779	1,584	2,795	8,162
Shared Services and Other Administrative Costs	1,270	1,160	1,019	989	1,113	2,212	2,375
External Costs	135	589	691	490	731	238	212
Property Taxes	55	52	69	64	66	68	70
TOTAL	**47,243**	**49,028**	**52,802**	**52,131**	**56,671**	**87,814**	**126,568**

2.0 DESCRIPTION OF OM&A CATEGORIES

The categories that comprise the overall OM&A envelope are described below.

2.1 GENERATION OM&A

The Generation OM&A budget represents costs required to maintain and operate the existing generation stations and associated facilities to meet community loads. The proposed costs are intended to ensure that the overall reliability of the generating assets is maintained and that customer commitments are achieved, and that all legislative, regulatory and safety requirements are met. Details of the expenditures under this program are provided at Exhibit D, Tab 1, Schedule 2.

2.2 FUEL OM&A

The Fuel OM&A budget represents costs required to transport, transfer and supply diesel fuel to enable electricity generation and is Remotes' largest OM&A line item. The proposed costs are intended to ensure the continued operation of generation assets and overall system reliability. Details of the expenditures under this program are described in Exhibit D, Tab 1, Schedule 3.

2.3 DISTRIBUTION OM&A

The Distribution OM&A budget represents planned maintenance, forestry and right-of-way maintenance, trouble response, data collection and system condition assessment, and meter re-verification, testing and checking. The proposed costs are intended to ensure that the overall reliability of the distribution systems is improved, that customer commitments are met, and that all legislative, regulatory, environmental and safety requirements are met. Details of the expenditures under this program are described in detail at Exhibit D, Tab 1, Schedule 4.

2.4 CUSTOMER CARE OM&A

The Customer Care OM&A expenses represent the costs associated with meter reading, customer billing, collections, and bad debt expenses. Details of the expenditures under this program are filed at Exhibit D, Tab 1, Schedule 5.

2.5 COMMUNITY RELATIONS OM&A

The Community Relations OM&A work program includes Conservation and Demand Management (CDM) program, the Customer Advisory Board (CAB), Customer Outreach and Program Delivery, and public safety measures. Details of the expenditures under this program are filed at Exhibit D, Tab 1, Schedule 6.

2.6 COST OF POWER OM&A

Cost of Power includes the cost of all electricity energy purchased for resale through grid connection. Details of the expenditures are grouped under Other Power Supply Expenses OM&A and are filed at Exhibit D, Tab 1, Schedule 7.

2.7 WATAY TRANSMISSION CONNECTION COST

Watay transmission connection cost is the revenue requirement impact arising from the Remote Connection Lines capital and OM&A expense that is charged to Remotes as a direct expense, through a rate applicable to service provided from the Remote Connection Lines (refer to EB-2018-0190 and EB-2021-0134), and is filed at Exhibit D, Tab 1, Schedule 7.

2.8 SHARED SERVICES AND OTHER ADMINISTRATIVE COSTS OM&A

The Shared Services and Other Administrative costs include the common corporate functions and services (ie. legal, finance, corporate) to support the Remotes business, as well as the maintenance of existing infrastructure, including business systems, facilities, and information technology. Other OM&A programs also include the credits for overheads capitalized. Details of the expenditures under this program are filed at Exhibit D, Tab 1, Schedule 8.

2.9 COST OF EXTERNAL WORK

Remotes performs a small amount of unregulated external work. There are three main areas of work: assistance to the Electricity Safety Authority to facilitate inspections of Remotes' distribution systems and of customer installations; maintenance of streetlights; and assessments of the Independent Power Authorities. External work is described in Exhibit D, Tab 2, Schedule 1.

2.10 PROPERTY TAXES

Remotes' property taxes payments are regulated under the *Electricity Act 1998*, the *Municipal Act 2001*, and the *Assessment Act 1990*. Details of the expenditures in this category are filed at Exhibit D, Tab 6, Schedule 1.

Additional details specific to each of the OM&A categories listed in the above, including detailed variance explanations, can be found in the exhibit references outlined in Table 3.

Table 3 - OM&A Cost Categories and Evidence References *(in thousands $)*

Program Areas	2023 Test Year	% of Total 2023 OM&A	Reference
Generation	$12,574	9.9%	Exhibit D, Tab 1, Sch 2
Fuel	$30,365	24.0%	Exhibit D, Tab 1, Sch 3
Distribution	$3,745	3.0%	Exhibit D, Tab 1, Sch 4
Customer Care	$2,383	1.9%	Exhibit D, Tab 1, Sch 5
Community Relations	$682	0.5%	Exhibit D, Tab 1, Sch 6
Cost of Power	$8,162	6.4%	Exhibit D, Tab 1, Sch 7
Watay Transmission Connection Cost	$66,000	52.1%	Exhibit D, Tab 1, Sch 7
Shared Services and Other Administrative Costs, including LEAP deductions	$2,129	1.7%	Exhibit D, Tab 1, Sch 8
Cost of External Work	$458	0.4%	Exhibit D, Tab 2, Sch 1
Property Taxes	$70	0.1%	Exhibit D, Tab 6, Sch 1
Total	**$126,568**	**100%**	

GENERATION OM&A

1.0 SUMMARY OF GENERATION OM&A

Due to the lack of grid connection, Remotes generates electricity to meet its obligations under section 29 of the *Electricity Act, 1998*. Diesel generation is currently the prime source of electricity within the communities. Remote also operates two run-of-the-river mini-hydro electric generating facilities. The feasibility of using further renewable technologies is continually examined as new technologies evolve, but diesel is currently the most reliable and cost-effective technology.

There are presently 57 diesel generators in service, ranging in size from 60 kW to 1,500 kW. Most stations have three generators, sized to meet community load at different times of the day. Automated operation ensures that the generation units are run to maximize fuel efficiency by matching the generator size to the community load. Currently, Remotes handles over 20 million litres of fuel each year.

Remotes has fuel storage tanks (tank farms) within each community to ensure adequate diesel fuel supply. Tanks are equipped with measurement and alarm devices to reduce the risk of fuel spills and to enhance fuel control measurement. Most tanks are double-walled to enhance containment.

Due to the high cost of transportation to the communities, Remotes' staff generally reside in the communities while undertaking planned and unplanned maintenance. Remotes maintains staff houses and bush bungalows at 18 sites. Commercial accommodations are used at the other sites.

The forecasted Generation Operation & Maintenance OM&A expenditures for 2023 are $12,574k. These expenditures are required to meet customer, regulatory and statutory requirements regarding service and reliability.

Table 1 provides a summary of Remotes' Generation Operation & Maintenance OM&A expenditures for the historical, bridge, and test years.

Table 1 - Generation OM&A *(in thousands $)*

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Generation Maintenance	10,626	9,790	9,679	9,373	9,703	9,069	7,952
Generation Operations	4,596	4,290	4,867	4,861	4,587	5,064	4,622
Total	**15,222**	**14,080**	**14,546**	**14,234**	**14,290**	**14,133**	**12,574**

Variances are shown below by category.

2.0 GENERATION OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSIONS

The sections below summarize the Test year costs for each of the Remotes Generation OM&A programs.

2.1 GENERATION MAINTENANCE

The forecasted Generation Maintenance OM&A expenditures for 2023 are $7,952k.

PROGRAM INTRODUCTION

Generation maintenance includes planned and unplanned maintenance related to the generation site, buildings, engines, systems and fuel storage and fuel systems. Planned maintenance prevents premature equipment and system failures and contributes to service reliability. Unplanned maintenance includes maintenance and repair related to trouble reports and equipment or component failures.

Maintenance of Diesel Engines

Planned maintenance of diesel engines is prescribed by the engine manufacturer and is required to keep generating units available and operating to meet community load. Intensive maintenance procedures are scheduled based on engine operating hours and vary from year to year. Forecasts of engine planned maintenance are based on forecast engine operating hours, not the age of the unit. Actual engine maintenance performed varies according to actual load in the community and the hours each engine is picked to run by the automated control system.

Maintenance of Hydro Stations

Regular maintenance is performed on the run-of-the-river hydro stations and involves hydraulic system maintenance, gear box maintenance, generator maintenance, switchgear and control maintenance and turbine checks. Unplanned maintenance may also be performed in response to issues identified during routine station operation. This can include, but is not limited to, the water intake and outflow, the generator units and auxiliary equipment, gear, communications, and the station building/site.

Shoulderblade Falls Benefit-Sharing (Hydro Station)

During the 1990s, Ontario Hydro, Deer Lake First Nation and ISC jointly funded the construction of a small hydroelectric station at Shoulderblade Falls as a demonstration of renewable technology in the north. This partnership has been a successful relationship for all parties for over 25 years and currently helps to produce about one quarter of the Deer Lake's annual power needs. This renewable asset is owned by Deer Lake First Nation, operated, and maintained by Remotes, with benefit-sharing to the Deer Lake First Nation for the unrestricted access and use of the Shoulderblade Falls Hydro assets.

Maintenance of Plant and Auxiliary Systems

Planned maintenance of plant and auxiliary systems includes inspection and maintenance of: all electrical system and SCADA systems; secondary heating systems; engine fuel controls, primary cooling, aftercooling systems, and ventilation systems; overhead cranes; and mandatory annual inspection and maintenance of fire suppression systems. The plant auxiliary systems were installed when stations were newly constructed, and must be maintained, tested, inspected, and calibrated to keep them in service.

Maintenance of Buildings

Planned maintenance related to structures includes civil repair work (required to maintain all generating station buildings, fences, yard sites and staff houses), annual inspections, and bi-annual sampling of water facilities for the staff houses and generation stations. Where a station upgrade is planned to replace a station, delays to station upgrades mean that ongoing civil repair work increases significantly as buildings that were expected to be replaced continue to age and require increased maintenance.

Maintenance of Tank Farms

Planned maintenance of tank farms includes expenditures required to inspect, maintain, and address deficiencies in the generating station fuel offload, bulk storage tanks and fuel transfer equipment to keep fuel systems in standard operating condition. Fuel system maintenance is directly related to Remotes' responsibility for station operation as prescribed in the Electrification Agreements, Canadian Standards Association (CSA)'s fuel regulations B-139-15, and Canadian Council of Ministers of the Environment (CCME)'s "Environmental Code of Practice for Aboveground and Underground Storage Tank Systems Containing Petroleum and Allied Petroleum Products".

Design, Construction and Asset Management (Engineering) Support

Design, Construction and Asset Management maintenance programs and projects are related to improvements in the efficiency, safety and operation of generation assets and include engineering investigations, failure analysis investigations, drawing update projects, and support for renewable energy proponents.

TEST EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for Generation Maintenance based on a forecast of engine hours. The forecast for engine maintenance varies according to actual load in the community and the hours each engine is picked to run by the automated control system. Remaining maintenance programs are based on a 5-year historical average, adjusted for CPI and for those communities connecting to the grid. Table 2 below sets out Remotes' planned expenditures for the 2023 test year, along with the forecast and actual spending levels for the bridge and historical years, for the Generation Maintenance program, followed by supporting variance explanations.

Table 2 - Generation Maintenance OM&A *(in thousands $)*

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Generation Maintenance	10,626	9,790	9,679	9,373	9,703	9,069	7,952

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecasted expenditures are $2,674k lower primarily due to decreased DGS operations, and unplanned engine and auxiliary maintenance because of grid connection, and reallocation of $702k of common facility costs to maintenance of General Plant, partially offset by the introduction of backup power maintenance.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $1,751k lower primarily due to decreased unplanned engine and auxiliary maintenance because of grid connection and the reallocation of common facility costs to Maintenance of General Plant, partially offset by the introduction of backup power maintenance.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecasted expenditures are $1,117k lower primarily associated with lower maintenance of engines, auxiliary and plant systems due to grid connection, partially offset by the introduction of backup power maintenance.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $634k lower primarily due to decreased engine and auxiliary maintenance, based on a maintenance schedule that fluctuates year to year, and reallocation of common facility costs to maintenance of General Plant, and the impact of communities connecting to the grid.

2018 ACTUALS VS 2018 OEB-APPROVED

- actual expenditures were $836k lower primarily due to lower maintenance of auxiliary systems and renewable energy maintenance, and decreased costs in drawing design standards and drawing operational support due to shift in resources to focus on corrective measures program. These decreases were partially offset by increases to the corrective measures program and environmental improvements.

2.2 GENERATION OPERATIONS

The forecasted Generation Operations OM&A expenditures for 2023 are $4,622k.

PROGRAM INTRODUCTION

Generation Operations represent expenditures required for safe and reliable day to day operation of the generating plants and are required to keep the generating station and associated facilities in a standard operating condition as required to meet community load. This is associated with Remotes' responsibilities prescribed by the Electrification Agreements, the environmental approval to operate the Generating Station under the *Environmental Protection Act*, and Section 6.2.27 of the Distribution System Code.

The inaccessibility of its service territory is Remotes' greatest operational risk. Within each community, Remotes contracts for local operators, who perform regular routine inspection and maintenance of equipment at generating facilities including the generating units, auxiliary equipment and the bulk storage tank farm. The operators provide on-site monitoring of fuel deliveries, and the safe handling, transportation and disposal of waste. Operators are also responsible for keeping the stations clean, undertaking filter changes, checking diesel plants and reporting and troubleshooting problems to the Thunder Bay Service Centre. Operators are also responsible for responding to emergencies such as power outages, house fires and spills.

Operations staff in Thunder Bay are responsible for ensuring that the diesel plants operate safely and reliably. Operations staff are also the primary contact for the operators, responsible for supervising and scheduling, developing plant-specific procedures, logistical and troubleshooting support, assisting the operator in emergency response, plant reporting and for ensuring that the operators are competent to perform daily maintenance activities. Operations staff are responsible for conducting and documenting operator training. Each operator must successfully complete a comprehensive on-site training program each year. On average, each operator requires annual refresher training of two weeks to operate the plant systems, respond to emergencies and perform day to day maintenance.

Generation operations also include a variety of environmental programs. These programs are conducted to ensure that Remotes complies with all legal and corporate requirements related to environmental protection, including obtaining and respecting environmental approvals, permits for the transportation of dangerous goods, and with various reporting requirements under the *Environmental Protection Act.*

In 1999, Remotes developed an Environmental Management System (EMS) to help improve environmental performance. The EMS is registered to the ISO 14001 standard and requires regular audits, spills prevention, support and training for staff and agents, and internal and public communications.

Generation operations, excluding fuel and power purchases, in the historic, bridge and test years are presented in Table 3 below.

EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for Generation Operations based on a 5-year historical average, adjusted for CPI and communities connecting to the grid. Table 3 below sets out Remotes' planned expenditures for the 2023 test year, along with forecast and actual spending levels for the bridge and historical years, for the Generation Operations program, followed by supporting variance explanations.

Table 3 - Generation Operations OM&A *(in thousands $)*

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Generation Operations	4,596	4,290	4,867	4,861	4,587	5,064	4,622

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecasted expenditures are $26k higher primarily due to increased backup power operations, including IPAs, offset by decreased DGS operations due to communities connecting to the grid.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $35k higher primarily due to increased backup power operations, including IPAs, offset by decreased DGS operations due to communities connecting to the grid.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- Forecasted expenditures are $442k lower primarily due to the impact of communities connecting to the grid.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $477k higher primarily associated with increased post COVID onsite one-on-one operator and environmental training.

2018 ACTUALS VS 2018 OEB-APPROVED

- actuals expenditures were $306k lower primarily due to lower plant operations and reduced spill management and monitoring.

This page has been left blank intentionally.

FUEL OM&A

1.0 SUMMARY OF FUEL OM&A

Diesel generation is currently the most reliable and cost-effective generation method for most remote communities, both in Ontario and abroad. The majority of Remotes' electricity is generated using diesel fuel. The size and isolation of Remotes' service territory means that fuel use, transportation and storage of fuel are the most significant driver of Remotes cost structure, and routinely represent over 60% annually of its direct OM&A costs. Currently, Remotes handles over 20 million litres of fuel each year.

Table 1 provides a summary of Fuel OM&A expenditures for the historical, bridge, and test years.

Table 1 - Fuel OM&A *(in thousands $)*

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Fuel	25,900	29,406	30,251	29,166	34,481	41,200	30,365

2.0 FUEL OM&A PROGRAM DESCRIPTION AND VARIANCE DISCUSSION

The forecast Generation Fuel OM&A expenditures for 2023 are $30,365k.

PROGRAM INTRODUCTION

Fuel Cost Management

Overall fuel costs are affected by three main factors: price, volume and delivery. Two of these factors can be influenced by Remotes, volume and costs of delivery. Remotes has several initiatives underway to address volume. To influence fuel volumes, Remotes makes CDM, and Renewable energy program available to customers, and is also installing new, more fuel-efficient engines when engines are at end of life.

Since 2007, Remotes has been reducing delivery costs, by improving delivery contracts for both air and winter road fuel by improving supplier contracts, requiring that fuel levels are drawn down in advance of winter road openings and by continuing to expand its contracting with First Nation-owned tank farms for the supply and storage of winter road fuel. Fuel commodity prices, on the other hand, are the result of market forces and are not within Remotes' control.

To reduce diesel fuel usage, Remotes has done the following:

- Introduced a CDM program and supported the development of community-led energy planning discussed in Exhibit D Tab 1, Schedule 6;
- Operated and introduced customer-owned Renewable Energy Technologies (REINDEER program) generation facilities discussed in Exhibit A, Tab 1, Schedule 6;
- Invested in improving fuel generating efficiency through a proactive scheduled maintenance program; and
- Maintained an active generation asset replacement program and introduced more efficient technology.

Despite these efforts, fuel volume and usage are contingent on customer demand. Remotes is continuing to see an increase in energy use throughout its communities, as our customers continue to embrace the ever-changing electronic world. As such, Remotes only has limited influence on overall fuel volumes required to meet customer demand.

To mitigate the impact of delivery costs Remotes has done the following:

- Negotiated long-term fuel delivery contracts with multiple suppliers;
- Maximized winter road deliveries (cheaper delivery methods) where possible through supplier relationships and improved tank storage; and
- Negotiated an increased number of fuel contracts directly with the First Nation communities with fuel storage on site where Remotes does not have adequate fuel storage facilities to take advantage of winter road delivery pricing.

Despite these efforts, delivery costs are largely driven by location, distance, and access of which Remotes' has no ability to influence.

TEST EXPENDITURE FORECAST LEVEL

Remotes forecasts load to plan for and meet customer loads, to estimate customer revenues and to forecast its fuel and maintenance costs. As a result of Remotes' break-even business model, cost and revenue differences between forecast loads and forecast fuel costs do not result in a profit or loss to Remotes but are added to or drawn from the RRRP Variance Account. The load forecast methodology and statistics related to load forecast are discussed in more detail in Exhibit C, Tab 1, Schedule 1, and in the supporting schedules to that Exhibit.

Remotes tracks actual historical load data on energy usage by community, customer class, and time period. This historical data provides the baseline starting point for forecasting usage/kWh sold. Adjustments are made to this baseline data on a going-forward basis using average load growth, historical customer growth patterns and seasonality. Feedback is solicited from communities about upcoming construction or community programs that may impact future loads.

The Load Forecast (kWhs sold) forms the basis of the fuel forecast. Once the load forecast is established, historic operating fuel efficiency ratios and load loss rates are utilized to forecast generated kWhs and fuel litres required. The fuel forecast is done on a site-by-site basis, given different load characteristics and plant efficiencies.

Expected fuel commodity prices are based on market prices at the time the forecast is made. Fuel commodity prices are based on New York Harbour Ultra Low Sulfur Diesel (ULSD) future prices. As there is no Canadian forecast for diesel fuel commodity prices, commodity pricing is confirmed through a high-level analysis of the published fuel indices that are used by each supplier.

The cost of delivery accounts for about 50% of the delivered price of fuel. As a result, supply delivery contract data is critical in developing the forecast costs. Supplier contracts are subject to a competitive tendering process and delivery costs are forecast based on supplier contracts and historical deliveries of winter road fuel. Air delivery typically constitutes about 62% of fuel delivered to Remotes' communities, followed by all-weather road delivery at 16%, winter road delivery at 7% and First Nation contracts at about 14%. Table 2 shows how the forecast for the 2023 Test Year Fuel Cost was derived.

Table 2 - 2023 Total Fuel Cost Forecast

Fuel Efficiency (kWh/litre)	3.73
Total litres of fuel issued (in kL)	14,359
Average delivered cost per litre ($)	$2.1147
Total Cost of Fuel (in $k)	$30,365

Table 3 below sets out Remotes' planned expenditures for the 2023 test year, along with forecast and actual spending levels for the bridge and historical years for the Fuel program, followed by supporting variance explanations.

Table 3 - Fuel OM&A *(in thousands $, u.o.s)*

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Total Litres, *in thousands*	17,314	18,728	19,413	20,169	20,449	20,107	14,359
Fuel cost/Litre	$1.4959	$1.5702	$1.5583	$1.4461	$1.6862	$2.0490	$2.1147
Total Fuel Cost	$25,900	$29,406	$30,251	$29,166	$34,481	$41,200	$30,365

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecasted expenditures are $4,465k higher due to the increase in unit price, partially offset by decreased volume associated with lower community load as the balance of the communities are connected to the grid.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $4,416k lower primarily due to decreased volume associated with lower community load as communities are connected to the grid, partially offset by increased unit price.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecasted expenditures are $10,835k lower primarily due to decreased volume associated with lower community load as the balance of communities are connected to the grid, partially offset by increased unit price.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $6,719k higher primarily due to an increase in unit price, partially offset by decreased fuel volumes as communities are connected to the grid.

2018 ACTUALS VS 2018 OEB-APPROVED

- actuals expenditures were $3,506k higher primarily due to increased fuel volumes associated with higher community load and increased unit price.

This page has been left blank intentionally.

DISTRIBUTION OM&A

1.0 SUMMARY OF DISTRIBUTION OM&A

Remotes served approximately 4,368 customers at the end of 2021 through nineteen isolated distribution systems to serve twenty-one communities and one community connected to the province's electricity grid. Within each system, Remotes is responsible for transformation, voltage regulation, delivery and metering of power. The distribution systems are isolated, distinct and stand-alone, due to the distance between each community. These distribution systems operate at distribution voltages ranging from 4.16 kV to 25 kV. The distribution in-service assets maintained by Remotes include approximately 272 kilometers of distribution line and 1,174 transformers distributed throughout the system, which are used for voltage transformation.

The forecasted Distribution OM&A expenditures for 2023 are $3,745k. These expenditures are driven by the need to meet customer, regulatory and statutory requirements regarding service and reliability.

Table 1 provides a summary of Remotes' Distribution OM&A expenditures for the historical, bridge, and test years.

Table 1 - Distribution OM&A (*in thousands $*)

Category	Board Approved	Historic (Actuals)				Bridge	Test
	2018	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Distribution Maintenance	1,898	1,696	1,970	2,921	2,066	2,429	3,268
Distribution Operations	116	62	108	154	524	561	477
Total	**2,014**	**1,758**	**2,078**	**3,075**	**2,590**	**2,990**	**3,745**

Variances are shown below by category.

2.0 DISTRIBUTION OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSIONS

The sections below summarize the Test year costs for each of the Remotes Distribution OM&A programs.

2.1 DISTRIBUTION MAINTENANCE

The forecasted Distribution Maintenance OM&A expenditures for 2023 are $3,268k.

PROGRAM INTRODUCTION

Distribution maintenance includes both planned and unplanned maintenance and trouble calls. Unplanned power interruptions on the distribution system generally result from line component failures and contact by trees or animals. Unplanned maintenance is reactive and varies due to external factors such as storms, variability in equipment deterioration and random equipment failures. Planned maintenance includes equipment maintenance that is primarily cyclical in nature, including maintenance of line equipment (reclosers and line regulators).

Distribution maintenance also includes costs associated with metering. Revenue metering is federally regulated under the *Electricity and Gas Inspection Act* and is governed by Measurement Canada. Under Measurement Canada regulations, all revenue meters must be approved and routinely inspected and maintained. Remotes complies with Measurement Canada rules and regulations. Based on Measurement Canada rules, meters must regularly be removed from service to verify that they are performing accurately and within specifications. Electricity customers require a meter to measure their electricity usage, and the proper functioning of billing meters is essential to ensure customers are accurately billed.

TEST EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for Distribution Maintenance based on a historical 3-year average, adjusted for CPI and communities connecting to the grid. Forecast for new IPAs added to Remotes' service territory are based on existing communities of similar size that Remotes currently serves. Table 2 below sets out Remotes' planned expenditure levels for the

2023 test year, along with the forecast and actual spending levels for the bridge and historical years, for the Distribution Maintenance OM&A program, followed by the supporting variance.

Table 2 - Distribution Maintenance OM&A (*in thousands $)*

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Distribution Maintenance	1,898	1,696	1,970	2,921	2,066	2,429	3,268

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecasted expenditures are $1,370k higher primarily due to increased trouble response and maintenance resulting from new IPAs connecting to the grid and increased meter service provider costs.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $1,202k higher primarily due to increased trouble response and maintenance resulting from new IPAs connecting to the grid and increased meter service provider costs.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecasted expenditures are $839k higher primarily due to three new IPAs connecting to the grid, resulting in increased unplanned maintenance, trouble calls, and meter service provider costs.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $363k higher primarily due to increased trouble response and maintenance resulting from new IPAs connecting to the grid.

2018 ACTUALS VS 2018 OEB-APPROVED

- actuals expenditures were $202k lower primarily due to a delay in executing forestry activities.

2.2 DISTRIBUTION OPERATIONS

The forecasted Distribution Operations OM&A expenditures for 2023 are $477k.

PROGRAM INTRODUCTION

Distribution operations includes data collection and system condition assessment used to plan corrective and preventative maintenance, joint use activities and engineering support for distribution. The Distribution System Code requires that all local distribution companies assess the condition of its assets and patrol their distribution lines to identify structural problems, damaged equipment and components that may cause a power interruption, as well as any hazards such as leaning poles, damaged equipment enclosures and vandalism.

TEST EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for Distribution Operations, other than data collection program, based on a historical 3-year average, adjusted for CPI and communities connecting to the grid. The data collection program is based on the 5-year OEB data requirement cycle. Table 3 below sets out Remotes' planned expenditures for the 2023 test year, along with forecast and actual spending levels for the bridge and historical years, for the Distribution Operations program, followed by supporting variance explanations.

Table 3 - Distribution Operations OM&A (*in thousands $)*

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Distribution Operations	116	62	108	154	524	561	477

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecasted expenditures are $361k higher primarily by the impact of communities connecting to the grid relating to transition costs, project management, and settlement services.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $47k lower primarily due to decreased data collection activities as the bulk of data collection occurred in 2021 in preparation for the 2023 COS filing, partially offset by transition costs, project management, and settlement services relating to grid connected communities.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecasted expenditures are $84k lower primarily due to decreased data collection activities as the bulk of data collection occurred in 2021 in preparation for the 2023 COS filing.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $37k higher primarily due to project management, transition costs, and settlement services relating to grid connection, partially offset by decreased data collection activities as the bulk of data collection occurred in 2021 in preparation for the 2023 COS filing.

2018 ACTUALS VS 2018 OEB-APPROVED

- forecasted expenditures were $59k lower with no significant variance of note.

This page has been left blank intentionally.

CUSTOMER CARE OM&A

1.0 SUMMARY OF CUSTOMER CARE OM&A

Remotes provides general customer account services including in-community customer service activities to all customers connected to its distribution system. These services are established by Remotes' Distribution Licence, rate schedules, and in the Codes and Rules established by the Board and are documented in Remotes' Conditions of Service.

The forecasted Customer Care OM&A expenditures for 2023 are $2,383k and include $111k for bad debt. These expenditures are required for billing, collections, meter reading, and responding to customer inquiries and complaints.

Table 1 provides a summary of Remotes' Customer Care OM&A expenditures for the historical, bridge, and test years.

Table 1 - Customer Care OM&A (*in thousands $*)

Category	Board Approved	Historic (Actuals)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Customer Care	2,151	1,800	1,860	1,563	1,556	2,149	2,272
Bad Debt (Recovery)	0	12	122	312	(147)	69	111
Total	**2,151**	**1,812**	**1,982**	**1,875**	**1,409**	**2,218**	**2,383**

Variances are shown below by category.

2.0 CUSTOMER CARE OM&A PROGRAM DESCRIPTION AND VARIANCE DISCUSSION

The sections below summarize the test year costs for each of the Remotes Customer Care OM&A programs.

2.1 CUSTOMER CARE

The forecasted Customer Care OM&A expenditures for 2023 are $2,272k.

PROGRAM INTRODUCTION

Customer care expenses include costs to read meters, bill customers, collect on outstanding accounts and respond to customer inquiries. Remotes has three staff in the Thunder Bay service centre who are responsible for entering meter readings into the Customer Service System, answering customer calls and inquiries, entering bill payments, organizing collection trips, contacting customers and Band Councils prior to collection activity and negotiating payment arrangements. Field staff undertake collection activities in the communities. Meter reading is primarily contracted out through Band Councils to individuals in the communities.

TEST EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for Customer Care based on the historical 5-year average, adjusted for CPI and IPAs entering Remotes' service territory. Table 2 below sets out Remotes' planned expenditures for the 2023 test year, along with forecast and actual spending levels for the bridge and historical years, for the Customer Care program, followed by supporting variance explanations

Table 2 - Customer Care OM&A (*in thousands $*)

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Customer Care	2,151	1,800	1,860	1,563	1,556	2,149	2,272

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecast expenditures are $121k higher primarily due to increased collection costs and the addition of Pikangikum.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast expenditures are $716k higher primarily due to the balance of IPAs entering Remotes service territory and the resumption of collection activities, which were cancelled due to the COVID-19 pandemic.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecast expenditures are $123k higher primarily due to the inclusion of new IPAs entering Remotes' service territory.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast expenditures are $593k higher primarily due to the inclusion of new IPAs into Remotes' service territory and the resumption of collection activities which were cancelled due to COVID-19 pandemic.

2018 ACTUALS VS 2018 OEB-APPROVED

- actual expenditures were $351k lower primarily because project design and the implementation of Pikangikum into the CIS billing system was less than anticipated and the Customer Service and Community Relation officer position was not in place until the end of 2018.

2.2 BAD DEBT EXPENSE

The forecasted Bad Debt OM&A expenditures for 2023 are $111k.

PROGRAM INTRODUCTION

Bad debt expense is made up of direct write-offs offset by recoveries, plus adjustments to the provision for bad debts. Direct write-offs are generally attributed to customers leaving Remotes' service territory without payment. Recoveries are often made when customers re-enter Remotes' service territory or pay previously written-off arrears. Reviewed annually, the bad debt provision is based on historical data, accounts receivable aging by account type, and approved by management should provision rates change.

TEST EXPENDITURE FORECAST LEVEL

The bad debt allowance is based on a combination of applying a model percentage against outstanding energy accounts receivables and specific identification of high-risk receivables. The provision is an allowance taken against receivables where full recovery is in doubt and is determined using allowance rates on previous actual payment history, the normal payment curve and specific adjustments for large or unusual receivables based on management judgment. Adjustments to this allowance are charged to bad debt expense when outstanding receivables increase. When outstanding balances are reduced, the provision is reduced, and the adjustments are credited to bad debts.

Table 3 below sets out Remotes' planned expenditures for the 2023 test year, along with forecast and actual spending levels for the bridge and historical years, for the Bad Debt expense, followed by supporting variance explanations.

Table 3 - Bad Debt Expense (*in thousands $*)

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Bad Debt (Recovery)	0	12	122	312	(147)	69	111

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- Forecast expenditures are $111k higher due to increased customer count and IPAs entering Remotes' service territory.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- Forecast expenditures are $258k higher because of IPAs entering Remotes' service territory and 2021 year including a successful collection trip that has been postponed since 2020 due to the COVID-19 pandemic, resulting in bad debts recovered.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- Forecast expenditures are $42k higher, which is not a material variance.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- Forecast expenditures are $216k higher because of IPAs entering Remotes' service territory and 2021 year including a successful collection trip that has been postponed since 2020 due to the COVID-19 pandemic, resulting in bad debts recovered.

2018 ACTUALS VS 2018 OEB-APPROVED

- Actual expenditures were $12k higher, which is not a material variance.

This page has been left blank intentionally.

COMMUNITY RELATIONS OM&A

1.0 SUMMARY OF COMMUNITY RELATIONS OM&A, PROGRAM DESCRIPTION & VARIANCE DISCUSSIONS

SUMMARY & PROGRAM INTRODUCTION

The forecasted Community Relations OM&A expenditures for 2023 are $682k. These expenditures are required for various customer outreach activities, including a Conservation and Demand Management (CDM) program, the Customer Advisory Board (CAB), Customer Outreach and Program Delivery, and public safety measures. Most of these activities are fulfilled by the Customer Service and Community Relations officer position, which was implemented after the 2018 COS settlement conference.

There are no costs for dedicated CDM staff to support IESO programs funded under the 2021-2024 CDM Framework are included in the revenue requirement.

TEST EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for the Community Relations program based on 5-year historical costs, programs and expected engagement plans. Table 1 below sets out Remotes' planned expenditures for the 2023 test year, along with forecast and actual spending levels for the bridge and historical years, for the Community Relations program, followed by supporting variance explanations.

Table 1 - Community Relations OM&A *(in thousands $)*

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Community Relations	496	157	703	459	407	675	682

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecast expenditures are $186k higher primarily due to the increased activities of the Customer Outreach and Program Delivery relating to the addition of new IPAs entering Remotes' service territory.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast expenditures are $275k higher primarily due to the increased activities relating to the addition of new IPAs entering Remotes' service territory and a return to pre-COVID-19 activities.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecast expenditures are $7k higher with no significant variances noted.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast expenditures are $268k higher primarily due to the increased activities relating to the addition of new IPAs entering Remotes' service territory and a return to pre-COVID-19 activities.

2018 ACTUALS VS 2018 OEB-APPROVED

- actual expenditures were $339k lower primarily due to Customer Service and Community Relations officer position being delayed until the end of 2018, resulting in lower Customer Outreach and Program Delivery.

OTHER POWER SUPPLY EXPENSES OM&A

1.0 SUMMARY OF OTHER POWER SUPPLY EXPENSES OM&A

The Wataynikaneyap transmission grid connection project (Watay Project) is a generational project that will revolutionize energy in Northern Ontario. The Watay Project corresponds to the construction of a transmission line that will connect 16 remote First Nation communities in Northern Ontario to the provincial Ontario Power Grid by 2024 (2022-2, 2023-9, 2024-5). Cat Lake (currently served by Networks), and 6 additional communities, which are currently unregulated Independent Power Authorities (IPAs), are anticipated to be added to Remotes' service area via transfer or Watay grid connection by the end of 2024. As direct result of the Watay transmission project, 'other power supply expenses' OM&A is expected to increase going forward reflecting the cost of power purchases.

The forecasted Other Power Supply OM&A expenditures for 2023 are $74,162k and include $66,000k related to the Watay transmission connection cost. This expenditure is required to provide power to the grid connected communities. The Cost of Power OM&A is forecasted based on the grid power purchased rates charged for Pikangikum, the load forecast specific to each community, and scheduled timing of grid connection.

Table 1 provides a summary of Remotes' Other Power Supply OM&A expenditures for the historical, bridge, and test years.

Table 1 - Other Power Supply Expenses (*in thousands $*)

Category	Board Approved	Historic (Actuals)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Cost of Power	0	14	1,463	1,779	1,584	2,795	8,162
Watay Transmission Connection Costs	0	0	0	0	0	21,285	66,000
Total	**0**	**14**	**1,463**	**1,779**	**1,584**	**24,080**	**74,162**

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecast expenditures are $74,162k higher primarily due to higher cost of power expenses and a higher Watay transmission connection cost resulting from nine existing communities that Remotes serves, along with five new IPAs connecting to the grid.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast expenditures are $72,578k higher primarily due to higher cost of power expenses and a higher Watay transmission connection cost resulting from nine existing communities that Remotes serves, along with five new IPAs connecting to the grid.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecast expenditures are $50,082k higher primarily due to higher cost of power expenses and a higher Watay transmission connection cost resulting from the balance of new IPAs and remaining communities that Remotes serves, connecting to the grid.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast expenditures are $22,496k higher primarily due to higher cost of power expenses and a higher Watay transmission connection cost resulting from two existing communities that Remotes serves.

2018 ACTUALS VS 2018 OEB-APPROVED

- actual expenditures were $14k higher due to higher cost of power expense with no variance of note.

2.0 OTHER POWER SUPPLY EXPENSES PROGRAM DESCRIPTION & VARIANCE DISCUSSIONS

The sections below summarize the test year costs for each of Remotes' Other Power Supply OM&A programs.

2.1 COST OF POWER

The forecasted Cost of Power expenses for 2023 is $8,162k. The 2023 Test Year Forecast expenses are detailed in Exhibit D, Tab 1, Schedule 7, Attachment 1.

PROGRAM INTRODUCTION

Once communities become Watay grid connected, Remotes will be required to pay the cost of power to the IESO. North Caribou and Kingfisher are expected to be connected in the fall of 2022 and Pikangikum, which is already grid connected, is expected to be re-connected using a higher voltage feed. The remaining communities are expected to be connected by the end of 2024. It is probable that the presented Watay grid connection dates will slip over time given construction and earlier COVID-19 delays.

Customer count and load forecast graphs are provided in the DSP.

TEST EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for cost of power based on the expected load of specific communities, the timing of grid connection and the cost of power currently experienced in Pikangikum. Table 2 below sets out Remotes' planned expenditures for the 2023 test year, along with the forecast and actual spending levels for the bridge and historical years, for the cost of power followed by supporting variance explanations.

Table 2 - Cost of Power Expense (*in thousands $*)

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Cost of Power	0	14	1,463	1,779	1,584	2,795	8,162

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecast expenditures are $8,162k higher primarily due to the addition of 11 Watay grid connected communities.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast expenditures are $6,578k higher primarily due to the addition of 11 Watay grid connected communities.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecast expenditures are $5,367k higher primarily due to due to the addition of 9 Watay grid connected communities in 2023.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast expenditures are $1,211k higher primarily due to the addition of 2 Watay grid connected communities in 2022.

2018 ACTUALS VS 2018 OEB-APPROVED

- actual expenditures were $14k due to the addition of Pikangikum.

2.2 WATAY TRANSMISSION CONNECTION COST

The forecast Watay Transmission Connection Cost expenses for 2023 are $66,000k.

PROGRAM INTRODUCTION

As part of the cost recovery and rate framework approved in the Watay's Leave to Construct Decision (EB-2021-0134), the OEB approved exemptions from the provisions of the Transmission System Code that would otherwise have required Remotes to make a capital contribution towards the cost of constructing the Remote Connection Lines. Instead, Watay will calculate a distinct revenue requirement for the Remote Connection Lines and recover that revenue requirement through a monthly fixed charge to Remotes. In accordance with regulations under the Ontario Energy Board Act, the expense incurred by Remotes in respect of these monthly fixed charges will form part of Remotes' revenue requirement and thereby part of the RRRP funding calculation to Remotes.

The Watay transmission connection cost is the revenue requirement impact arising from the Remote Connection Lines capital and OM&A expense that is charged to Remotes as a direct expense through a rate applicable to service provided from the Remote Connection Lines (please refer to EB-2018-0190 and EB-2021-0134).

TEST EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for the Watay Transmission Connection Cost based on approved amounts through EB-2018-0190. The Watay Transmission Connection Cost is the offsetting expense to the RRRP–Watay as described in Exhibit G, Tab 1, Schedule 1. As per EB-2018-0190, the amount is expected to be paid monthly at a fixed rate and updated should future amounts change.

Table 3 below sets out Remotes' planned expenditures for the 2023 test year, along with forecast and actual spending levels for the bridge and historical years, for the Watay Transmission Connection Cost program, followed by supporting variance explanations.

Table 3 - Watay Transmission Connection Costs (*in thousands $*)

Category	OEB-Approved	Historical (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Watay Transmission Connection Cost	0	0	0	0	0	21,285	66,000

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecasted expenditures are $66,000k higher primarily due to the Watay transmission connection cost.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $66,000k higher primarily due to the Watay transmission connection cost.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecasted expenditures are $44,715k higher primarily due to more communities being connected to the Watay grid and construction progression.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecasted expenditures are $21,285k higher primarily due to the initial introduction of the Watay transmission connection cost.

2018 ACTUALS VS 2018 OEB-APPROVED

- No variance noted.

COST OF POWER CALCULATION

This exhibit has been filed separately in MS Excel format.

SHARED SERVICES AND OTHER ADMINISTRATIVE COSTS

1.0 SUMMARY OF SHARED SERVICES AND OTHER ADMINISTRATIVE COSTS OM&A

The shared service model allows for the delivery of specialized services performed by Hydro One without replicating these functions within each separate subsidiary. The methodology and allocations of shared services and assets from Hydro One to Remotes is supported by the updated 2023 Black & Veatch (B&V) Study filed in EB-2021-0110, Exhibit E, Tab 4, Schedule 8, Attachment 1. A copy has been included as Attachment 1 to this Exhibit.

Shared Services include common corporate functions and services (CCF&S), Enterprise Technology Services (ETS), Telecommunications Services, System Service & Lease of Computer Equipment, Customer System Operations, and Supply Chain Services. In addition to these categories, Remotes also includes Other Administrative Costs, Direct Program Assignments, Capitalized Overheads, Miscellaneous General Expenses, Total Maintenance of General Plant, and Other Post-Employment Benefit (OPEB) adjustments. Other Administrative Costs are further broken down into Regulatory Expenses and Low-Income Energy Assistance Program (LEAP) expenses.

The funding associated with these programs:

- Ensures availability of required specialized professional expertise and resources in diverse areas;
- Ensures application of consistent policies, governance frameworks, business processes;
- Rationalizes and offers consistent levels of service across all Hydro One subsidiaries irrespective of size (human resources, pay and financial services, infrastructure support);
- Uses common technology systems and platforms providing better access to high quality and accurate information and to required services; and
- Allows Remotes to benefit from economies of scale in such areas as accounts payable processing, procurement processes and management of supplier relationships.

The forecasted Shared Services and Other Administrative Costs OM&A expenditures for 2023 are $2,375k and include $826k related to deductions for direct program assignments and capitalized overheads and $190k related to OPEB adjustments.

Table 1 provides a summary of Remotes' Shared Services and Other Administrative Costs expenditures for the historical, bridge, and test years.

Table 1 - Total Shared Services and Other Administrative Costs (*in thousands $*)

Description	Historical					Bridge	Test
	2018 OEB Approved	2018	2019	2020	2021	2022	2023
Shared Services							
CCF&S	954	688	617	628	798	877	891
Telecommunications Services	140	145	129	140	132	131	133
System Services & Lease of Computer Equipment	261	327	327	327	327	327	402
Other Services	208	442	394	399	370	291	290
Customer System Operations*	47	44	37	35	25	26	27
Supply Chain Services*	76	76	76	76	76	76	76
Total Shared Services	**1,686**	**1,722**	**1,580**	**1,605**	**1,728**	**1,728**	**1,819**
Other Administrative Costs							
Other Admin - Regulatory Expenses	103	66	17	18	11	101	32
Other Admin - LEAP	51	51	79	65	71	65	82
Less Direct Program Assignments*	(123)	(120)	(113)	(111)	(101)	(102)	(103)
Less Capitalized Overheads	(448)	(559)	(544)	(588)	(596)	(718)	(723)
Total Miscellaneous General Expenses	-	-	-	-	-	246	246
Total Maintenance of General Plant	-	-	-	-	-	702	832
Add OPEB Adjustments	-	-	-	-	-	190	190
Total Shared Services and Other Administrative Costs	**1,269**	**1,160**	**1,019**	**989**	**1,113**	**2,212**	**2,375**

**CSO and Supply Chain Services are recovered through direct program assignments.*

2.0 TOTAL SHARED SERVICES PROGRAM DESCRIPTIONS & VARIANCE DISCUSSIONS

PROGRAM INTRODUCTION

Descriptions of key service components of Shared Services OM&A are included below. All services may not be listed.

CCF&S	General counsel services – legal, governance, compliance, etc. Financial services - business planning, financial reporting, taxation, internal audit, risk management etc. Corporate services – human resources, labour relations, ISD, security operations, corporate communications, real estate, etc.
Other Services	Applications and infrastructure related to CSO, Finance, Human Resources applications, and related infrastructure services. ISD Information Management services include Internet access, IT Security tools provision, and management for internet services and telecom.
Telecommunications Services	Various telecommunications services including field and engineering, logistics, corporate, construction, telecommunication and information technology services.
System Services & Lease of Computer Equipment	SAP enterprise Asset Management Solution including various modules including customer and billing. Other system software, data management software, operating systems, system tools. Computer hardware and equipment.
Customer System Operations	Provision of bill production, dispatch and settlements service, customer contact centre services, and data services.
Supply Chain Services	Management & procurement, vendor management, process development, data management and investment recovery.

TEST EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for Shared Services are based on the current allocation model, as adjusted annually. Other Administrative Costs are based on historical data and upcoming plans.

Total program variances are as discussed below.

2023 Test Year vs. 2018 OEB-Approved (last OEB-Approved)

- forecasted expenditures are $1,106k higher primarily due Miscellaneous General Expenses and Maintenance of General Plant resulting from reallocation of costs from Generation Maintenance of Structures account.

2023 Test Year vs. 2021 Actuals (most recent actuals)

- forecasted expenditures are $1,261k higher primarily due to higher Miscellaneous General Expenses and Maintenance of General Plant resulting from reallocation of common facility costs from Generation Maintenance of Structures and Costs and Expenses of Merchandising accounts.

2023 Test Year vs. 2022 Bridge Year

- forecasted expenditures are $163k higher with no significant variances noted.

2022 Bridge Year vs. 2021 Actuals (most recent actuals)

- forecasted expenditures are $1,099k higher primarily due to higher Miscellaneous General Expenses and Maintenance of General Plant resulting from reallocation of common facility costs from Maintenance of Structures and Costs and Expenses of Merchandising accounts.

2018 Actuals vs 2018 OEB-Approved

- forecasted expenditures are $109k lower with no material variances noted.

Hydro One Networks Inc.

REPORT ON CORPORATE COST ALLOCATION REVIEW

JUNE 9, 2021

BLACK & VEATCH

Table of Contents

List of Tables

List of Figures

1 Glossary

Affiliate: A corporation is an affiliate of another if one of them is a subsidiary of the other or both are subsidies of the same corporation or each is controlled by the same person, as further defined in the Business Corporations Act (Ontario).

Affiliate Relationships Code: Ontario Energy Board's Affiliate Relationships Code for Electricity Distributors and Transmitters, revised March 15, 2010, sets out rules that govern the conduct of utilities as that conduct relates to their respective Affiliates. This code covers a number of objectives with the following two relating to the content of this report and the 2020 Review: (1) protecting ratepayers from harm that may arise as a result of dealings between a utility and its affiliate; (2) preventing a utility from cross-subsidizing affiliate activities.

Capitalized Common Corporate Costs: A portion of applicable Common Corporate Costs that support capital expenditures and are included as overhead costs on Transmission and Distribution capital expenditures.

Common Corporate Costs: Costs incurred to provide Shared Services to Hydro One and its affiliate companies.

Corporate & Shared Cost Allocation Methodology: The methods and processes employed to allocate common corporate costs among Hydro One, its Affiliates, and the Tx and Dx businesses comprised of three components: (1) the allocation of Common Corporate Costs, (2) a methodology for capitalizing Common Corporate Costs for the Tx and Dx businesses, and (3) a methodology to allocate the use of Shared Assets.

Cost Causation: The guiding principle for cost allocation is that cost responsibility should follow cost causation. Cost causation means that there is a causal relationship between the basis used to allocate a cost, and the cost that has been incurred. Costs are recognized as being caused by a service or group of services if (a) the costs are brought into existence as a direct result of providing the service or group of services; or (b) the costs are avoided if the service or group of services is not provided.

Cost Center: The lowest tier of Hydro One's organizational structure where Costs Centers roll-up into individual Line of Businesses.

Overhead Capitalization Rate: Percentages that are applied to the cost of Transmission and Distribution capital expenditures to recover the Capitalized Common Corporate Costs.

Overhead Capitalization Rate Methodology: The methods and processes employed to develop the Overhead Capitalization Rate for the Transmission business and the Overhead Capitalization Rate for the Distribution business.

Shared Assets: Tangible and intangible fixed assets that are held by Hydro One Networks and are utilized by multiple businesses of Hydro One.

Shared Services: Centralized business operations that support multiple businesses, affiliated companies, or multiple parts of the same organization.

2 Summary

2.1 PURPOSE AND ORGANIZATION OF REPORT

Black & Veatch Canada Company ("Black & Veatch") is pleased to submit to Torys LLP, as legal counsel on behalf of Hydro One Networks Inc. ("Hydro One"), this Report which describes our Corporate & Shared Cost Allocation Methodology review. The review conducted by Black & Veatch establishes a methodology to allocate corporate costs among Hydro One, its affiliate companies, and between the Transmission ("Tx") and Distribution ("Dx") businesses with three components: (1) a methodology to allocate Hydro One's common corporate operation, maintenance, and administrative ("OM&A") costs ("Common Corporate Costs"), (2) a methodology for capitalizing a portion of Common Corporate Costs for the Tx and Dx businesses, and (3) a methodology to allocate the use of Shared Assets. In general, the methods employed across these three components are described collectively as Hydro One's Corporate & Shared Cost Allocation Methodology. Our work updating and evaluating Hydro One's Corporate & Shared Cost Allocation Methodology began in April 2020 and continued through May 2021. The focus of this review was to ensure that the Corporate & Shared Cost Allocation Methodology distributes costs in an accurate manner that is consistent with Ontario Energy Board ("OEB") precedent as well as generally acceptable regulatory practices for cost allocation.

Black & Veatch is experienced in conducting affiliate cost allocation reviews across North America and have provided reports to Hydro One on their Corporate & Shared Cost Allocation Methodology since 2005. The general methodology first recommended by Black & Veatch, adopted by Hydro One, and accepted by the OEB during Black & Veatch's first engagement in 2005 has been applied to Hydro One's Business Plans, and reviewed by Black & Veatch with subsequent reports issued in numerous Tx and Dx base rate proceedings. A list of these past reviews and reports is provided in Appendix A.

In the OEB's March 7, 2019 decision in the matter of Hydro One's Distribution Rates for 2018 to 2022 (EB-2017-0049), the OEB indicated that, as part of Hydro One's rebasing application for Transmission revenue requirement and Distribution rates for 2023-2027, the OEB intends to examine Hydro One's Corporate & Shared Cost Allocation Methodology in detail. The OEB reiterated this expectation in its decision on Hydro One's Transmission Rate application for 2020-2022 (EB-2019-0082). The goal of this Report is to provide details on Hydro One's methods to aid in the OEB's understanding and review. Further, during past reviews, reports were prepared and submitted independently for the three components (allocation of Common Corporate Costs, capitalization of Common Corporate Costs, and allocation of Shared Assets) and separately for the Tx and Dx businesses. This report will cover the three components jointly and discuss the results for both the Tx and Dx businesses. The major sections of this report are described below.

1. Glossary –Definitions of key terms used within this report.

2. Summary – Provides a description of the report, Black & Veatch's assignment, descriptions of the three components, and executive summary of the conclusions.

3. Corporate Cost Allocation Framework – Discusses the use of and reliance on Shared Services and Shared Assets and provides a description of the Hydro One organization.

4. Guiding Principles of Cost Allocation – Covers the primary principles employed in developing the Corporate & Shared Cost Allocation Methodology.

5. Allocation of Common Corporate Costs – Describes the methodology used to allocate Hydro One's Common Corporate Costs among Hydro One, its affiliate companies, and between the Tx and Dx businesses.

6. Overhead Capitalization Rate Methodology – Describes the methods used to develop the Overhead Capitalization Rates which are applied to the cost of Transmission and Distribution capital expenditures to recover the Capitalized Common Corporate Costs.

7. Allocation of Shared Assets – Describes the method used to allocate the use and cost of Shared Assets among Hydro One, its affiliate companies, and between the Tx and Dx businesses.

2.2 BLACK & VEATCH'S ASSIGNMENT

Black & Veatch focused our effort during this review on evaluating and identifying changes in the methodology that may be appropriate due to changes in the business of Hydro One, changes arising from outside factors (e.g., governmental or regulatory requirements), technological change (e.g., availability of additional or more detailed information), or other relevant considerations. The goal of this detailed and methodical review was to recommend and establish a best practice Corporate & Shared Cost Allocation Methodology for Hydro One for each of the three components described in detail below.

Consistent with Black & Veatch's standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., headcount, budgeted amounts) subject only to their overall reasonableness and factual accuracy, but without our independent confirmation.

2.3 COMPONENTS OF HYDRO ONE'S CORPORATE & SHARED COST ALLOCATION METHODOLOGY

The three components of Hydro One's Corporate & Shared Cost Allocation Methodology are described below.

2.3.1 Allocation of Common Corporate Costs

Common Corporate Costs are incurred to provide Shared Services to Hydro One and its affiliate companies. The provision of these Shared Services is centralized so there is a need to allocate costs across the various Affiliates utilizing either cost drivers (e.g., certain Human Resources costs are allocated on company headcount) or time surveys and studies (e.g., interview and time tracking studies). The purpose of these allocations is to ensure no cross-subsidization between Affiliates nor between the Tx and Dx businesses by allocating Common Corporate Costs in accordance with the level of services being received.

An overview of the methodology is described below:

- Through interviews with Hydro One personnel, identify the Shared Services included in Common Corporate Costs and the particular activities performed to provide these Shared Services.
- Through interviews with Hydro One personnel, time surveys, and analyses of time spent by employees, distribute the costs of each Shared Service among the activities performed by that Line of Business to provide that Shared Service.
- Distribute the cost of each activity among Hydro One, its affiliate companies, and between the Tx and Dx businesses based on direct assignment (see Section 4.3) or on cost drivers (see Section 4.4) when direct assignment is not possible.

Further, in instances when costs associated with Common Corporate Costs can be directly attributed to work for a specific affiliate and are expected to be for a minimum period of three months, those costs are transferred via variable timesheets or automatic transfers. These costs are not included in Hydro One's Corporate & Shared Cost Allocation Methodology given they are recorded and transferred prior to determining the total Common Corporate Costs that are included in the allocation methodology.

2.3.2 Capitalizing Common Corporate Costs for Tx and Dx Businesses

Common Corporate Costs support both OM&A expenditures and capital expenditures; so there is a need to further distinguish Common Corporate Costs between those that (a) only support OM&A expenditures, (b) directly support capital expenditures, and (c) are overhead costs that support both OM&A expenditures and capital expenditures. Those costs that directly support capital expenditures and a portion of the overhead costs that support both OM&A expenditures and capital expenditures, are recovered through an Overhead Capitalization Rate. This rate is an additional charge on capital expenditures to recover Common Corporate Costs in proportion to the amount of Shared Services used to support those projects. Costs that only support OM&A expenditures are excluded from this calculation.

The general methodology employed is first to review Shared Service activities to ascertain if the activity directly supports OM&A, directly supports capital, or supports both capital and OM&A. Second, to split the costs that support both capital and OM&A between (a) costs that remain OM&A, and (b) costs that will be included in the Overhead Capitalization Rate calculation and thereby capitalized (by applying a 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio). Third, the total Capitalized Common Corporate Costs are calculated by adding (1) the portion of overhead costs directly relating to capital and (2) the Shared Service activities relating to capital - the result of splitting costs that support both capital and OM&A. The total Capitalized Common Corporate Costs is then divided by the total Capital Expenditures to determine the Overhead Capitalization Rate.

2.3.3 Allocation of Shared Assets

In addition to the allocation of Common Corporate Costs it is necessary for compliance with the Affiliate Relationships Code to also allocate the use of Shared Assets among Hydro One, its affiliate companies, and between the Tx and Dx businesses. The general process employed to conduct this review was to gain an understanding of the particular nature of the Shared Assets, the Shared Services that the Shared Assets provide support for, and the use of the Shared Assets by Hydro One, its Affiliates, and the Tx and Dx businesses. With this understanding, allocation options were reviewed and decided upon to allocate the costs of these Shared Assets among Hydro One, its

Affiliates, and the Tx and Dx businesses. The results of this allocation support the development of the Tx and Dx revenue requirements and transfer pricing relating to the use of Shared Assets.

2.4 EXECUTIVE SUMMARY - RESULTS OF REVIEW

Black & Veatch believes that Hydro One's Corporate & Shared Cost Allocation Methodology is appropriate for Hydro One, because it achieves the purposes for which it was designed: to distribute costs in a manner that is consistent with OEB precedent and established regulatory practice for cost allocation, to ensure legislative compliance (i.e., Hydro One Accountability Act), and to promote transparency and efficiency.

While the general methodology employed by Hydro One remains the same as past Corporate & Shared Cost Allocation Methodologies, there are a few modifications and improvements made during the 2020 review. The 2020 Review conducted by Black & Veatch resulted in the following enhancements:

Time Surveys - In each of the past reviews, some of the allocation factors were developed using time studies, whereby individuals across specific Shared Services (customer relations, asset management, and operations) tracked their daily time for a four-week period. As a result of feedback and considerations made by Black & Veatch during this 2020 Review, the four-week time study was replaced with a time survey in which individuals were asked about time spent by a particular Cost Center's employee or those employees were asked directly. Rather than review a specific four-week period through a time study, interviews were conducted, and details were provided on how the employees in these Cost Centers spend their time across the entire year by using a time survey.

Hydro One Accountability Act, 2018 (Bill 2) - During the 2020 review Black & Veatch recommended updating the methodology to reflect cost-causative principles when allocating all executive costs but to flag Hydro One Accountability Act, 2018 (Bill 2) costs so they can easily be traced through the method and excluded when developing any costs for ratepayer recovery.

Three-Factor Allocation Driver - For Hydro One's Corporate & Shared Cost Allocation Methodology the three-factor allocation driver based on Capital, Labour, and Revenue was utilized to reflect the fact that the effort associated with a certain activity relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity or by any particular allocation factor. Previously the methodology utilized two multi-factor allocations; (a) an equal weighting of total revenue and total assets and (b) an equal weighting of total revenue and total OM&A.

The methods being employed by Hydro One are directly in alignment with past methods resulting from the previous reviews conducted by Black & Veatch. While each review is unique and enhancements to the general methods have been made incrementally during each review they are in alignment with methods first recommended by Black & Veatch, adopted by Hydro One, and accepted by the OEB during Black & Veatch's first engagement in 2005. These methods have since been applied to Hydro One's Business Plans and reviewed by Black & Veatch with subsequent reports issued in numerous Tx and Dx rate proceedings. In these past rate proceedings, the results of Hydro One's Corporate & Shared Cost Allocation Methodology have directly been utilized in the development of Tx and Dx revenue requirements, subjected to intervenor and regulatory scrutiny and accepted by the OEB as part of the approved revenue requirement calculation methodology.

2.4.1 Summary Tables of Corporate & Shared Cost Allocation Methodology

Hydro One's Corporate & Shared Cost Allocation Methodology has been applied by Hydro One to its Business Plan data for 2023 and the results of this methodology for the three components are provided below.

Table 1 - Distribution of Annual Common Corporate Costs

Business	2023
($ Millions)	$
Transmission	130.59
Distribution	139.61
Other	33.62
Total	303.81
(% of Total)	%
Transmission	43%
Distribution	46%
Other	11%
Total	100%

Table 2 - Overhead Capitalization Rate for Tx and Dx Businesses

OVERHEAD CAPITALIZATION RATE	2023
Transmission Rate	8.00%
Distribution Rate	9.00%

Table 3 - Allocation of Shared Assets to Tx and Dx Businesses

Type	Asset Value	Transmission	Distribution	Other	Tx %	Dx %	Other %
Major Assets							
Buildings and Fixtures	$ 44.60	$ 19.96	$ 24.29	$ 0.35	44.75%	54.46%	0.79%
Communication equipm	$ 12.72	$ 6.41	$ 6.20	$ 0.11	50.38%	48.77%	0.85%
Computer Equip Major	$ 19.37	$ 7.48	$ 11.72	$ 0.16	38.63%	60.53%	0.83%
Computer Software	$ 144.25	$ 63.20	$ 76.12	$ 4.93	43.81%	52.77%	3.42%
Intangible-ContCap	$ 12.01	$ 11.16	$ 0.85	$ -	92.95%	7.05%	0.00%
Intangibles Software	$ 92.37	$ 23.80	$ 67.57	$ 1.00	25.76%	73.16%	1.08%
Land	$ 61.97	$ 29.41	$ 32.56	$ -	47.46%	52.54%	0.00%
Leasehold improvemnt	$ 3.18	$ 1.10	$ 2.08	$ -	34.61%	65.39%	0.00%
Syst supervisry equp	$ 0.36	$ 0.02	$ 0.34	$ 0.00	6.04%	93.65%	0.32%
Subtotal - Major Assets	$ 390.82	$ 162.54	$ 221.73	$ 6.55	41.59%	56.73%	1.68%
Minor Assets							
Transportation equip	$ 167.39	$ 54.15	$ 113.24	$ -	32.35%	67.65%	0.00%
Power operated equip	$ 88.97	$ 28.78	$ 60.19	$ -	32.35%	67.65%	0.00%
Aircraft & Railway	$ 5.48	$ 4.12	$ 1.36	$ -	75.18%	24.82%	0.00%
Comp Equip / Telecom	$ 8.07	$ 3.81	$ 4.06	$ 0.20	47.23%	50.30%	2.47%
Tools,shop,garag equ	$ 2.39	$ 1.29	$ 1.10	$ -	54.09%	45.91%	0.00%
Office furnitre Equp	$ 2.62	$ 1.27	$ 1.35	$ -	48.42%	51.58%	0.00%
Measurement & testin	$ 1.19	$ -	$ 1.19	$ -	0.00%	100.00%	0.00%
Misc. service equipm	$ 0.15	$ 0.08	$ 0.07	$ -	54.09%	45.91%	0.00%
Stores equipment	$ 0.18	$ 0.10	$ 0.08	$ 0.00	53.87%	45.72%	0.41%
Subtotal - Minor Assets	$ 276.45	$ 93.61	$ 182.64	$ 0.20	33.86%	66.07%	0.07%
Total - All Shared Assets	**$ 667.27**	**$ 256.15**	**$ 404.37**	**$ 6.75**	**38.39%**	**60.60%**	**1.01%**

3 Corporate Cost Allocation Framework

3.1 THE USE OF AND RELIANCE ON SHARED SERVICES AND ASSETS

Large corporations utilize Shared Services as an effective and efficient strategy for providing support services to affiliate companies and different business segments. The choice to provide Shared Services rather than to deliver services within each affiliate separately is dependent on the balance between the costs and benefits of decentralized and centralized provision of the services. The centralized provision of services benefits from economies of scale, efficient transfer of knowledge, common systems & support, and the ability of management to identify efficiencies and alignment across Affiliates. Decentralized operations can result in higher costs and different standards but also may provide a benefit of flexibility and recognition of specific requirements. For those services whose benefits outweigh the costs, the provision of the services centrally to multiple Affiliates is more desirable. For those services that require unique functions that only relate to one affiliate or in instances where the service benefits from the flexibility and ability to take into account the unique requirements of an affiliate these should remain decentralized. In the end, the balance of centralized vs. decentralized services is largely a question of corporate organizational strategy and will not be exactly the same for all entities. This is a similar question for Shared Assets, where questions of when to share the use of assets across multiple Affiliates and when to purchase assets solely to service one affiliate will depend on the nature of the asset and the particular requirements of the affiliate. Savings can be expected from economies of scale when investing in assets that serve multiple Affiliates; even if those Affiliates may be serving different markets (e.g., software infrastructure, office buildings).

Hydro One has developed an organizational structure to take advantage of the benefits of Shared Services and Shared Assets. There are still many functions and assets that remain decentralized given they are directly serving one affiliate or the Tx or Dx businesses, and benefit from direct fulfillment of specific and unique requirements of that affiliate or the Tx or Dx business.

3.2 HYDRO ONE'S ORGANIZATIONS

The Hydro One group of companies includes the wholly owned subsidiaries and partnerships listed in **Table 4**. The OEB regulates, separately, the businesses identified as such in **Table 4**. Each regulated business is required to account separately for its assets, revenues and costs, for both regulatory and financial accounting purposes.

Table 4 – Hydro One Affiliates and Businesses

SUBSIDIARY	BUSINESS SEGMENT	REGULATED	DESCRIPTION
Hydro One Ltd.	Holding	No	Public company that owns Hydro One Inc. and Hydro One Telecom Inc. and other non-regulated businesses. Hydro One Ltd. is owned by public shareholders as well as the Province of Ontario.
Hydro One Inc.	Holding	No	Subsidiary of Hydro One Ltd. Acts as the holding company of Hydro One's rate regulated businesses, including Hydro One Networks Inc.
Hydro One Networks Inc.	Distribution	Yes	Owns and operates a distribution system which spans approximately 75% of Ontario and serves over 1.3 million customers.
	Transmission	Yes	Owns and operates substantially all of Ontario's electricity transmission system.
	Non-Regulated	No	Costs incurred by Hydro One Networks in support of the Dx and Tx businesses that are not recoverable from ratepayers.
Hydro One Sault Ste. Marie Limited Partnership	HOSSM	Yes	Subsidiary company of Hydro One Inc. that connects Northern Ontario to Southern Ontario and is the second-largest electricity transmitter in the Province
Hydro One Remote Communities Inc.	Remotes	Yes	Subsidiary company of Hydro One Inc. that owns, operates, maintains and constructs generation and distribution assets used to supply of electricity to remote communities in northern Ontario.
B2M Limited Partnership	B2M Transmission	Yes	B2M is a partnership that carries on the business of owning and operating a continuous transmission line between the Bruce Nuclear Power Development and Hydro One's Milton Switching station.
Niagara Reinforcement Limited Partnership	NRLP Transmission	Yes	NRLP is a partnership that carries on the business of owning and operating a transmission circuit between the Allanburg Transmission Station near Niagara Falls and Hydro One's Middleport Transmission Station.
Hydro One Telecom Inc.	Telecom	No	Subsidiary company of Hydro One Ltd. that sells high bandwidth telecommunication services to carriers, Internet service providers, and large public and private sector organizations.

4 Guiding Principles of Cost Allocation

4.1 THE NEED FOR COST ALLOCATION

Cost allocation is required when costs are not tracked for each activity that relates to an individual recipient of services. For instance, a Shared Service employee in accounts payable could track time spent processing each invoice and the entity being charged for that invoice and this time sheet record could be used to allocate costs for that employee to each entity. However, this is not practical or desirable given invoices may relate to multiple entities, time spent may be on improving or ensuring the process of reviewing invoices is effective, and activity-based time tracking requires significant time for the employee simply to track their time spent. If this was always practical, then there would be no need for cost allocation principles or methods; costs would simply follow the time sheets for all employees. This however is not practical given the time and effort for employees to track their time and the fact that there will always be employees who work on processes or projects that simultaneously benefit multiple business entities (i.e., the accounts payable manager who trains employees and works with the information systems division to develop more streamlined processes).

4.2 PRINCIPLES OF COST ALLOCATION

The guiding principle for cost allocation is that cost responsibility should follow cost causation. As such, company policy and allocation methodology should satisfy the following criteria:

- The method should be based on cost causation. Cost causation means that there is a causal relationship between the basis used to allocate a cost, and the cost that has been incurred. Costs are recognized as being caused by a service or group of services if (a) the costs are brought into existence as a direct result of providing the service or group of services; or (b) the costs are avoided if the service or group of services is not provided.

- If cost causation cannot be used or is determined to be inappropriate in the circumstances, the method usually considered next is benefits received (i.e., allocated to the business that received the benefits).

- The method should be based on data that can be obtained at reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.

- When relying on estimates, results should be unbiased, reasonably consistent with comparable data, and provided by employees familiar with the costs.

4.3 METHODS OF COST ALLOCATION

There are two methods to allocate or distribute shared costs among a utility's businesses – **Direct Assignment** and **Allocation**.

Direct Assignment is used when it can be reasonably determined that all or a designated portion of an activity is performed for a particular business. Direct Assignment is completed through the use of time studies or time surveys; where participants either fill out time sheets during a sample period or provide an indication of how their time is spent throughout the year.

Allocation is used when more than one business uses an activity, but the portions of the activity that each use cannot be directly established through a time study or time survey. In this case, a cost driver must be assigned to distribute the costs of the activity. A cost driver is a formula for sharing the cost of an activity among those entities that cause the cost to be incurred.

4.4 COST DRIVERS

As stated above, a cost driver is a formula for sharing the cost of an activity among those entities that cause the cost to be incurred. The guiding principle that Black & Veatch uses in assigning cost drivers is cost causation and, in cases when cost causation cannot be easily established, cost drivers are assigned based on a review of the level of benefits received (e.g., diversity and inclusion activities may not be caused by a particular affiliate or group of businesses, but the benefits of the programs can accrue to the Affiliates and businesses who participate in the strategies, plans, programs and policies).

Other factors considered in assigning cost drivers include:

- **Practicality** – The cost driver should be understandable, obtainable at reasonable cost, and objectively verifiable in the initial year as well as in subsequent years.
- **Stability** – Cost driver values should be reasonably stable from year to year. When estimates are used, the cost driver should be able to be estimated with reasonable accuracy, and estimates should be unbiased.
- **Materiality** – When choosing between cost drivers, small differences can often be ignored in favor of the above-listed factors, Practicality and Stability.

4.5 TYPES OF COST DRIVERS

Cost drivers can be classified as **External** or **Internal**. **External** drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts. **Internal** drivers are based on values computed as an integral part of the cost allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the salaries of the people being supervised, and the cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities.

Table 5 – Types of Cost Drivers

TYPE	DESCRIPTION	EXAMPLES
External Cost Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Headcount (of employees), Kilometers of Lines
Financial	Financial information from accounting or management reports, budgets or projections	Capital expenditures, Net utility plant, Program Project Costs, Total capital, Total revenue
Blended or Multi-Factor	Weighted combinations of other drivers, used when one or more drives are applicable, and none is clearly preferable	Equal weighting of Capital, Labour, Revenue
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	Cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities

4.6 BLENDED OR MULTI-FACTOR ALLOCATION

The use of a multi-factor allocation to allocate costs that cannot be directly charged and for which a single cost allocation factor cannot be easily identified, is a broadly respected and common practice across the utility industry. The most common multi-factor allocation is a three-factor formula, with each factor equally weighted (generally referred to as the Massachusetts Formula), where the three components of the factor are representative of: (1) Capital, (2) Revenue, and (3) Labour. The implementation of the Massachusetts Formula varies slightly as entities use different measures to represent the three components (e.g., net plant/rate base, revenue/margin, labour/headcount).

Often the multi-factor allocator is chosen to account for the idea that the size and scope of a business impacts the level of services provided to that entity from certain common corporate services. The corporate services that are impacted by the size and scope of the business are typically executive costs, board of directors, corporate affairs, CFO/controller, general counsel, and strategic planning. These are high-level costs that relate to the oversight and strategy of the business. The inability to find a single direct assignment that is most appropriate leads to the use of a multi-factor allocation that reasonably represents the size and scope of the business, which impacts the time and effort spent or the service received from these common corporate services. In short, it is more common to see multi-factor allocations as the requirement for an allocation moves away from direct operations up the organization to high-level support and strategy where multiple factors relate to the time and effort spent and benefits received.

For Hydro One's Corporate & Shared Cost Allocation Methodology the three-factor allocation driver based on Capital, Labour, and Revenue was utilized as appropriate to reflect the fact that the effort associated with a certain activity relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity or by any particular allocation factor.

5 Allocation of Common Corporate Costs

5.1 PURPOSE OF ALLOCATING COMMON CORPORATE COSTS

Hydro One's organizational structure takes advantage of the benefits of Shared Services and as a result it is necessary to allocate the costs for these Shared Services among Hydro One, its affiliate companies, and between the Tx and Dx businesses. While this allocation is in place to avoid cross-subsidization and comply with the Affiliate Relationships Code it also allows Hydro One leadership to evaluate all costs incurred by each affiliate.

5.2 SHARED SERVICES

Hydro One provides Shared Services through the Lines of Business identified in **Table 6**, to the Affiliates and businesses identified in Table 4. Appendix B further describes the Lines of Business listed below.

Table 6 – Lines of Business Providing Shared Services

Cost Grouping	Line of Business
Corporate	Board of Directors Ombudsman President/CEO Office
Customer & Corp Affairs	Corporate Affairs Corporate Sustainability Customer Service External Relations Indigenous Relations
Finance	Audit Business Analysis Chief Financial Officer Corporate Controller Corporate Development Data Governance Facilities & Real Estate Investor Relations Outsourcing Pension Risk Strategic Finance Strategy & Innovation SVP Finance Tax

Cost Grouping	Line of Business
	Treasury
Human Resources	Change Management Labour Relations Talent Management Total Rewards Workforce Acquisition & Support Center
Information Solutions Division	Information Solutions Division
Legal & Secretariat	Corporate Secretariat General Counsel Regulatory Affairs
Operations	Chief Operating Officer Planning System Control

The Lines of Business in **Table 6** organize themselves into Cost Centers which may represent a single activity or multiple activities. For instance, the Audit Line of Business contains two Cost Centers one of which supports financial control assurance and the other provides four services relating to (1) financial statement support, (2) IT and technical audits, (3) operational audits, and (4) Telecom's audit support.

5.3 COST ALLOCATION METHODOLOGY

The allocation methodology for Hydro One's Common Corporate Costs was designed to address the following considerations:

- Compliance with relevant provisions of the Affiliate Relationships Code
- Cost incurrence- Are the costs needed to perform services required by the business?
- Cost allocation- Are costs appropriately allocated among businesses, based on the application of cost drivers /allocation factors supported by principles of causality?
- Cost/benefit- Do benefits received equal or exceed the cost?

An overview of the methodology is described below:

- Through interviews with Hydro One personnel, identify the Shared Services included in Common Corporate Costs and the particular activities performed to provide these Shared Services.

- Through interviews with Hydro One personnel, time surveys, and analyses of time spent by employees, distribute the costs of each Shared Service among the activities performed by that Line of Business to provide that Shared Service.
- Distribute the cost of each activity among Hydro One, its affiliate companies, and between the Tx and Dx businesses based on direct assignment (see Section 4.3) or on cost drivers (see Section 4.4) when direct assignment is not possible.

Further, in instances when Common Corporate Costs can be directly attributed to expenditures for a specific affiliate and are expected to be for a minimum period of three months, those costs are transferred via variable timesheets or automatic transfers. These costs are not included in Hydro One's Corporate & Shared Cost Allocation Methodology given they are recorded and transferred prior to determining the total Common Corporate Costs that are included in the allocation methodology.

The Corporate & Shared Cost Allocation Methodology was first applied to Hydro One's Business Plan (BP 2006-2010). Black & Veatch has also reviewed the application of the methodology to subsequent business plans, as listed in Appendix A. The purpose of this portion of the 2020 Review is to evaluate if the methodology is still appropriate, evaluate what changes may be appropriate, and to provide support to Hydro One in implementing those changes that are recommended.

Based on our discussions with Hydro One personnel and detailed review of the past methods employed, Black & Veatch determined that the Corporate & Shared Cost Allocation Methodology continues to be appropriate for Hydro One because:

- It meets best generally acceptable regulatory practices for cost allocation since it distributes costs based on cost causation, including the use of direct assignment when possible, and then through the use of cost drivers.
- It has been accepted by the OEB.
- It has the support of Hydro One management and is understood and accepted by Hydro One, its affiliate companies, and the Tx and Dx businesses.
- It allows Hydro One, its affiliate companies, and the Tx and Dx businesses to determine precisely what amounts they are charged by department and by activity within the department, and this transparency provides a basis for understanding the nature of the charges and value of the services received.

- It is well-integrated with Hydro One's annual business planning process and produces reasonably stable results over time.
- It accommodates changes in Hydro One's organization, and it can be adapted easily to reflect those changes.

5.4 UPDATES TO METHODOLOGY IN 2020

While the general methodology employed by Hydro One remains the same as past Corporate & Shared Cost Allocation Methodologies there are a few modifications and improvements made during the 2020 review.

5.4.1 Use of and Reliance on Time Studies

In each of the past reviews, some of the allocation factors were developed using time studies of individual employees' time spent between Tx and Dx businesses as well as between OM&A activities and capital expenditure activities. The time study involved individuals across specific Shared Services relating to customer relations, asset management, and network operations tracking their daily time for a four-week period. The time spent across these four weeks were then extrapolated across the entire year to allocate a full year of costs to the Affiliates and between supporting OM&A and capital. The reasonableness of this approach depends highly on two considerations, namely (1) whether the activities conducted during this four-week period accurately represent the activities across the entire year, and (2) whether the individuals are able to accurately track and determine which Affiliates they are serving during each day of the survey.

One area of focus with our detailed evaluation and review was to ascertain the appropriateness of time studies given the change in business operations due to the COVID-19 pandemic. In addition, Hydro One was interested in exploring whether Cost Centers that previously utilized a time study could be accurately allocated using an allocation factor or a time survey (i.e., the questions were asked, "Is there an allocation factor that can more accurately capture the split of responsibilities than a time study that occurs over a single four-week period? Is it reasonable to utilize a time survey and request management and/or employees to develop an estimate of time spent across the course of all twelve months?").

During the interviews with Hydro One personnel most familiar with the Shared Services, we discussed the current challenges of conducting a time study. One item of feedback received was the difficulty of conducting the time study given individuals were switching back and forth regularly between transmission support and distribution support. In the past, the three areas that were allocated on time studies were customer relations, asset management, and network operations. These areas have undergone changes in their organizational structures such that individuals are more often dedicated to either transmission or distribution, whereas in the past there was more time switching back and forth across the Tx and Dx businesses. As such, the new organizational structure facilitated a more direct allocation where employees were fully dedicated to one line of business or where management and/or employees could split an employee's time across Tx or Dx throughout a full twelve months.

As a result of this feedback and considerations made by Black & Veatch, the four-week time study was replaced with a time survey in which individuals were asked about time spent by a particular Cost Center's employee or those employees were asked directly. Rather than review a specific four-week period through a time study, interviews were conducted, and details were provided on how the employees in these Cost Centers spend their time across the entire year by using a time survey. Black & Veatch believes the replacement of the four-week time studies with time surveys more accurately captures the time spent by these Costs Centers on activities across the entire year and improves the allocation methodology.

5.4.2 Allocation of Certain Executive Costs to Shareholders - Hydro One Accountability Act, 2018 (Bill 2)

In the last review, Hydro One's Corporate & Shared Cost Allocation Methodology was updated to ensure compliance with section 78(5.0.2) of the Ontario Energy Board Act, which was introduced under the Hydro One Accountability Act, 2018 (Bill 2), requiring the OEB to ensure that Hydro One does not recover certain executive compensation costs from ratepayers and instead has those costs borne by Hydro One's shareholders. The previous methodology did this by directly assigning these costs to Hydro One's shareholders and as a result the methodology departed from a cost-based approach for those instances where such direct assignments were made. Black & Veatch found that departure and direct assignment to be appropriate given they were solely for legislative compliance purposes. During the 2020 evaluation and review Black & Veatch recommended updating the methodology to reflect cost-causative principles when allocating these executive costs but to flag those costs so they can easily be traced through the method and excluded when developing any costs for ratepayer recovery. This results in the same outcome, compliance with the Hydro One Accountability Act, 2018 (Bill 2), but allows for an accurate allocation of these costs to Hydro One, its affiliate companies, and the Tx and Dx businesses. This recommendation was adopted by Hydro One and is incorporated in the current methodology.

5.4.3 Use of a Three-Factor Allocation Driver

The use of a multi-factor allocation to allocate costs that cannot be directly charged and for which a single cost allocation factor cannot be easily identified, is a broadly respected and common practice across the utility industry. In past reviews these multi-factor allocations were (a) an equal weighting of total revenue and total assets and (b) an equal weighting of total revenue and total OM&A. The most common multi-factor allocation is a three-factor formula, with each factor equally weighted, and is generally referred to as the Massachusetts Formula, where the three components of the factor are representative of: (1) Capital, (2) Revenue, and (3) Labour. The implementation of the Massachusetts Formula varies slightly as entities use different measures to represent the three components (e.g., net plant/rate base, revenue/margin, labour/headcount).

For Hydro One's Corporate & Shared Cost Allocation Methodology the three-factor allocation driver based on Capital, Labour, and Revenue was utilized to reflect the fact that the effort associated with a certain activity relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity or by any particular allocation factor. Based on Black & Veatch's expertise and experience in performing cost allocation studies the use of the Capital, Labour, and Revenue multi-factor allocation is in alignment with industry practices, and its use reflects the nature of the activity and availability of information. For more details on the use of a multi-factor allocation please see Section 4.6.

Table 7 summarizes the allocation methods and costs drivers used to distribute the Common Corporate Costs among Hydro One, its Affiliates, and the Tx and Dx businesses.

Table 7 - Percentage Allocation of Common Corporate Costs Based on Direct Assignment and Cost Drivers

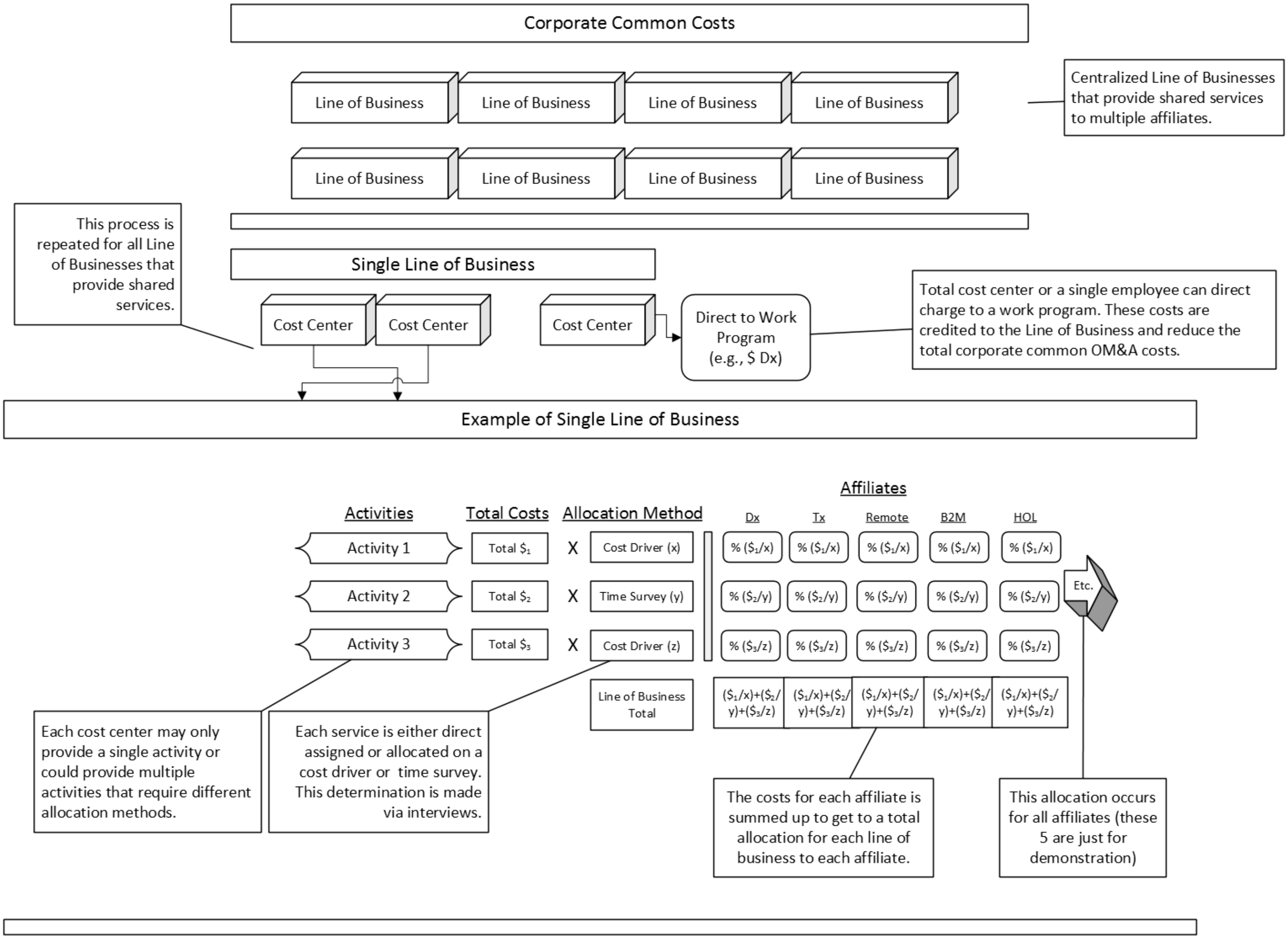
Cost Allocation Method	2023
Direct Assignment - Time Survey	43.98%
Capital, Labour, Revenue	20.00%
Headcount	10.34%
Customer Service (for CSO Sustainment)	7.62%
Internal - Total Cost Center Labour	6.16%
OM&A & Capital Expenditures	4.34%
Total Assets	2.51%
Direct Non-Labour Assignment	2.06%
Capital Expenditures	0.94%
Kilometers of Lines	0.84%
Other Allocators <0.5% for each	1.21%
Total	**100%**

These percentages are in alignment with previous reviews with respect to the percentage of total costs allocated based on direct costs (time survey or time study). In the previous Black & Veatch's Transmission report filed in EB-2019-0082 it was indicated that approximately 59% of costs were allocated using a direct assignment. In the current analyses the direct assigned costs are also approximately 59%, which is the sum of the rows (1) Direct Assignment – Time Survey (2) Customer Service Labour (for CSO Sustainment) (3) Internal – Total Cost Center Labour (for Non-Labour) and (4) Direct Non-Labour Assignment.

5.5 **REVIEW PROCESS EMPLOYED BY BLACK & VEATCH**

The general process employed to conduct this review was to evaluate the Lines of Business that provide Shared Services to identify specific activities undertaken, review allocation options for those activities, and develop those allocation factors or time surveys to allocate the costs associated with each activity among Hydro One, its Affiliates, and the Tx and Dx businesses. The method is depicted below in Figure 1.

Figure 1 –Common Corporate Cost Allocation Methodology



Task 1. Review Hydro One's current organizational structure and identify Lines of Business that provide Shared Services

The purpose of this Review was to evaluate which Lines of Business provide Shared Services to Hydro One, its Affiliates, and the Tx and Dx businesses. Hydro One captures these Common Corporate Costs within several Lines of Business which are listed in Table 6. Appendix B further describes the Lines of Business and Shared Services based on information provided by Hydro One in discussions and documents. The completion of this task resulted in the total Common Corporate Costs that provide Shared Services by Line of Business and the Cost Centers within each Line of Business.

Task 2. Identify the major activities performed in the provision of Shared Services

The purpose of this task was to identify the activities that are performed in order to provide each of the Shared Services. In short, it is the process of breaking down the Lines of Business into specific activities through reviewing budgeted data for Cost Centers and conducting interviews with each of the Lines of Business. To distribute the resources required to provide the Shared Services based on cost causation, the activities performed were identified and described by Hydro One to Black & Veatch. The activities performed often aligned with the budgeted Cost Centers or a subset of the Cost Center was determined to provide a particular activity. For example, the Line of Business 'Planning' contains four separate Cost Centers which were broken down into seven separate activities, each with a unique allocation factor applied.

Task 3. Review if the major activity provides support directly to OM&A, directly to Capital, or to both OM&A and Capital

The activities identified in Task 2 were also reviewed to ascertain if the activity directly supports OM&A, directly supports capital, or supports both capital and OM&A. This task does not directly support the allocation of Common Corporate Costs but rather supports the development of the Overhead Capitalization Rate calculation by simply flagging all Common Corporate Costs as one of these three categories. The purpose of this task was to flag those costs into three categories: (1) costs that should remain out of the overhead capitalization rate calculation as they are purely OM&A in nature, (2) costs that should be fully recovered from capital expenditures as they directly and wholly support capital expenditures, and (3) costs that support both OM&A and capital and must therefore be split between OM&A and capital within the Overhead Capitalization Rate calculation.

Task 4. Determine the level of costs incurred to perform the activities defined in Task 2

Once the activities were defined for each of the Lines of Business, the costs for each of these activities is derived using budgeted information for each Cost Center. If a Cost Center provides more than one activity, then the total Cost Center's cost was split across those activities based on input from Hydro One personnel familiar with the activities of that Cost Center.

Task 5. Review and choose an allocation methodology for each activity defined in Task 2

The purpose of this task was to choose which allocation method - either a time survey or a cost driver - is most appropriate for each activity. There are advantages and disadvantages to both time surveys and cost drivers. Time surveys can provide specific insights into how an employee or groups of employees spend time throughout a twelve-month period but also require judgement and estimation. Cost drivers are based on data but may not fully reflect the diversity in workload or the multi-faceted nature of what causes a cost to be incurred. Black & Veatch selected an allocation methodology and specific cost drivers based on applying the cost allocation principles discussed in Section 4, its expertise and experience in performing cost allocation studies, industry practices, and consultations with Hydro One as to the nature of each activity and availability of information. Section 4.5 Types of Cost Drivers describes the types of cost drivers.

Task 6. Determine which Affiliates and businesses are causing the activity to be performed or receiving the benefit of the activity

Once the allocation methodology was determined for a particular activity it was necessary to understand which affiliate companies or businesses were causing and/or receiving a benefit from that activity. The primary goal of this task was to ensure that costs were not being allocated to Affiliates who were not being served by the Shared Service activities. For instance, the Line of Business Strategic Finance provides Shared Services activity relating to capital expenditure decision support, for which the cost driver was determined to be Capital Costs, but Strategic Finance does not provide this support to Telecom. Thus, it was necessary to review each defined activity to determine which Affiliates should receive an allocation from the chosen cost driver.

Task 7. Review and determine allocation of non-labour costs

In addition to the detailed review conducted to determine the appropriate allocation methodology for labour costs, a review was completed to ensure non-labour costs were accurately allocated. In some instances, non-labour costs solely represent administrative and general departmental expenses for the Cost Center such as training for which those costs were allocated on the same basis as the labour dollars. In other instances where non-labour costs are unique in nature and should not follow the same allocation as labour a determination was made as to the appropriate cost driver.

Task 8. Populate cost drivers

The purpose of this task was to determine the values of each cost driver that are attributable to Hydro One, its Affiliates, and the Tx and Dx businesses in order to distribute the costs of each activity. The supporting information to develop these cost drivers was provided by Hydro One.

Task 9. Compute total Common Corporate Costs for Hydro One, its Affiliates, and the Tx and Dx businesses

The purpose of this task was to distribute the total cost of each activity based on the results of the time surveys and the chosen cost drivers. For allocations based on cost drivers, the amount allocated was computed by multiplying the activity cost to be allocated by the cost driver value for Hydro One, its Affiliates, and the Tx and Dx businesses. The culmination of Tasks 1-8 is the methodology for allocating the Common Corporate Costs which is applied in Task 9 to the costs within each Business Plan year for development of inputs into Hydro One's operating budgets.

5.6 CONCLUSIONS AND RESULTS

With the inclusion of the enhancements described above, Black & Veatch believes that Hydro One's current Common Corporate Cost allocation methodology is appropriate for Hydro One because it achieves the purposes for which it was designed: to distribute costs in a manner that is consistent with OEB precedent and regulatory practice for cost allocation, ensures legislative compliance (i.e., Hydro One Accountability Act), and promotes transparency and efficiency.

Table 8 presents the results of Hydro One's distribution of the Common Corporate Costs in Business Plan year 2023, among its Transmission, Distribution, and Other businesses.

Table 8 - Distribution of Annual Common Corporate Costs for Ratepayer Recovery

Business	2023
($ Millions)	$
Transmission	130.59
Distribution	139.61
Other	33.62
Total	303.81
(% of Total)	%
Transmission	43%
Distribution	46%
Other	11%
Total	100%

The Common Corporate Costs Allocation Methodology results in a similar outcome as the methods in the past with respect to the percentage of Common Corporate Costs allocated to the Transmission business, Distribution business, and Hydron One and its affiliates (the Other category). There was an approximate 3% movement from the Transmission business to the Distribution business between the results of the affiliate allocation methods applied to 2020 during the 2018 review with the results presented above for 2023 in **Table 8** (i.e., in the past Black & Veatch's Transmission report filed in EB-2019-0082 where the percentages were 46% Transmission and 43% Distribution, with the same 11% as Other). This movement of 3% is not concerning because (1) the results of the 2018 review for 2022 are not directly comparable to the results of the current allocations applied to 2023, and (2) changes in organizational structure and focus are to be expected as Hydro One evolves and adapts to new circumstances. For instance, reviewing past time surveys provided by Network Operations it was noted that this Line of Business is allocating a higher percentage to Distribution that reflects a higher focus on this area on the Distribution business and in particular on system planning activities for the Distribution business. Thus, the Common Corporate Costs Allocation Methodology reflects these changes in the organizational focus in the inputs to the methodology, impacting the allocation of costs to Hydro One, its Affiliates, and the Tx and Dx businesses.

6 Overhead Capitalization Rate Methodology

6.1 PURPOSE OF OVERHEAD CAPITALIZATION RATE

Overhead Capitalization Rates are percentages that are applied to the cost of Transmission and Distribution capital expenditures resulting in a portion of Common Corporate Costs being included as part of capital expenditures for each business. The Overhead Capitalization Rate is used to recover Common Corporate Costs that are not directly recorded to capital expenditures due to the nature of the costs; either employees who support capital expenditures but do not directly charge time to a specific capital project (assigned for less than three months or work on multiple projects simultaneously) or employees who perform work that impacts both capital and OM&A projects. For instance, time spent on risk evaluation and risk mitigation simultaneously impacts both capital and OM&A projects; without an efficient and effective risk evaluation and mitigation Hydro One would be unable to undertake OM&A and capital expenditures as effectively. In summary, the Overhead Capitalization Rate allocates to capital both (1) costs for Shared Service activities that directly support capital expenditures but are not billed directly to capital; and (2) costs for a portion of Shared Service activities that relate to both capital and OM&A simultaneously.

6.2 APPLICATION OF COST ALLOCATION PRINCIPLES TO OVERHEAD CAPITALIZATION RATE METHODOLOGY

In addition to alignment with the general principles of cost allocation discussed in Section 4 - Guiding Principles of Cost Allocation, the methodologies for overhead capitalization should address a set of formal, objective criteria that align with company and policy objectives. Guiding regulatory principles for the Capitalized Common Corporate Costs allocation methodology include:

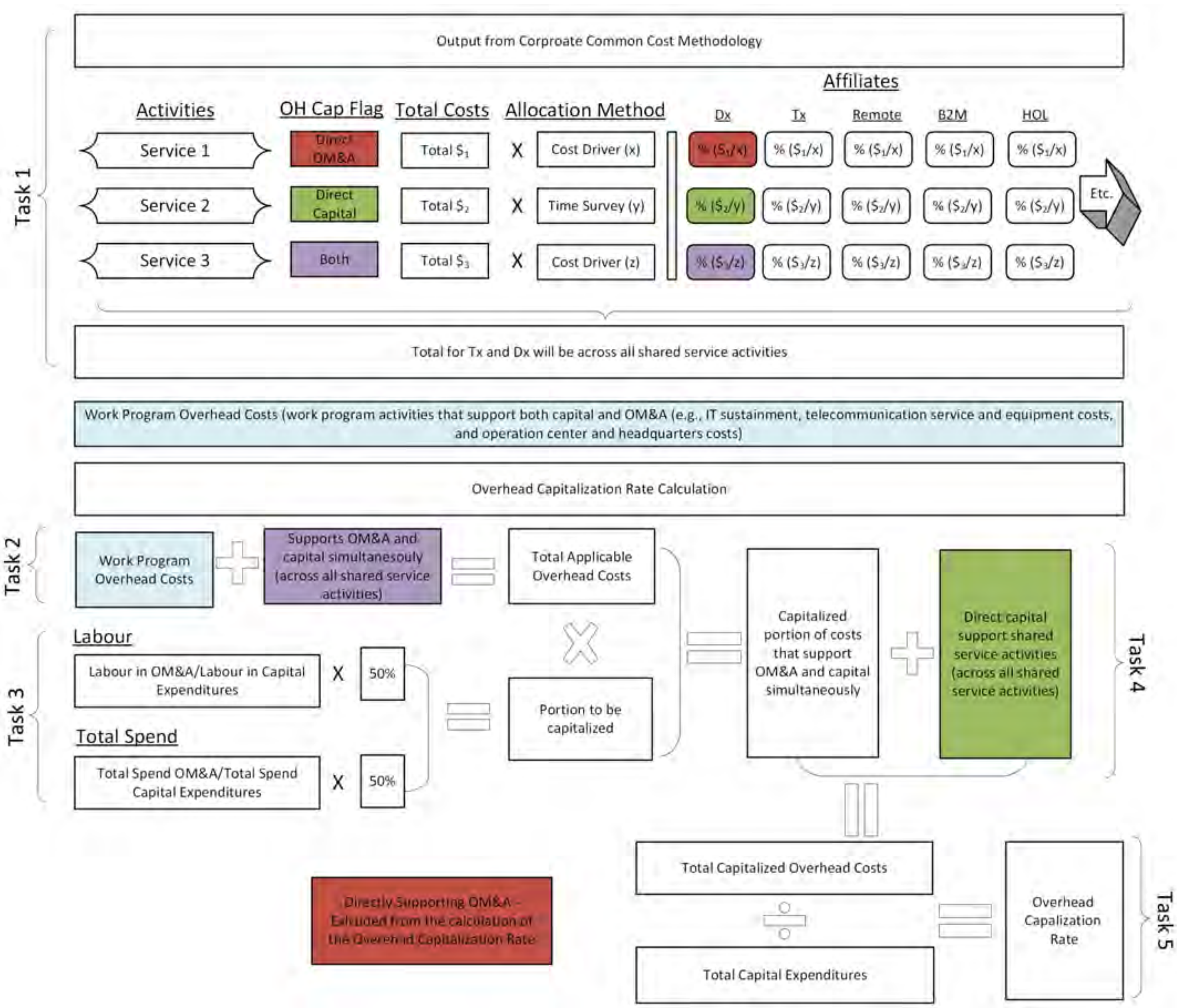
- **Defensible Cost Causation:** To conform to regulatory principles, the methodology should show a causal link between capitalized overhead and capital activity.
- **Distinguishable from Directly Allocated Capital Costs:** The overhead costs must be distinguished from those that are directly charged to capital (i.e., no duplication of costs and distinct sets of costs that are to be included in overhead).
- **Transparency:** The methodology and calculations should be easy to follow and understand by internal users and external reviewers.
- **Freedom from Bias**: The methodology should not contain a bias in the allocation of costs toward either operating or capital activities.

- **Stability:** The methodology should remain stable from year-to-year and not result in disproportionately large variations in the amounts of capitalized overhead from year-to-year.
- **Accuracy of Underlying Data:** Any data used in the methodology should be accurate and able to be relied upon for the purposes intended (i.e., provide an appropriate measure and reasonable approximation of the underlying volume of activity or output).
- **Flexibility/Adaptability:** The methodology should accommodate changes in organizational structure, availability of data, business processes, and information systems with reasonable ease. Where possible, the method should automatically adjust for changes in circumstances.
- **Cost-effectiveness:** Methodologies should be cost-effective to implement. Additional accuracy may require significant additional cost, and thus an appropriate balance is required between precision and cost, with respect to both implementation costs and on-going costs.

6.3 OVERVIEW OF METHODOLOGY

The purpose of this portion of the 2020 Review is to evaluate if the methodology is still appropriate, evaluate what changes may be appropriate, and to provide support to Hydro One in implementing those changes that are recommended. The final result of the Overhead Capitalization Rate Methodology is to develop two percentages (Overhead Capitalization Rates for Tx and for Dx) that are applied to the cost of Tx and Dx capital expenditures in order to recover a portion of Common Corporate Costs that support capital expenditures for each business. This process is depicted in **Figure 2** below.

Figure 2 - Overhead Capitalization Rate Methodology



The process to do so is described below and each task described is uniquely undertaken for each of the Tx and Dx businesses, since each business has a unique Overhead Capitalization Rate.

Task 1. Review if the major activity provides support directly to OM&A, directly to Capital, or to both OM&A and Capital

As noted in Task 3 of the review process for Common Corporate Cost allocation (section 5.5) each Shared Service activity was reviewed to ascertain if the activity directly supports OM&A, directly supports capital, or supports both capital and OM&A. The purpose of this task was to flag those costs into three categories: (1) costs that should remain out of the Overhead Capitalization Rate calculation as those costs are OM&A Only, (2) costs that should be fully recovered from capital expenditures as they directly and wholly support capital expenditures, and (3) costs that support both OM&A and capital and should therefore be split between OM&A and capital within the Overhead Capitalization Rate calculation. The result of this task and the outcome of the allocation of Common Corporate Costs is that each Shared Service activity allocated to the Tx and Dx businesses is within one of these three categories. (See the OH cap flag column within **Figure 4** above).

Task 2. Calculate Total Applicable Overhead Costs

In addition to the Lines of Business included and reviewed in the Common Corporate Cost allocation process, there are some additional work programs that provide Shared Services. These relate to IT sustainment, telecommunication service and equipment costs, and operation center and headquarters costs. The sum of the activities that support both OM&A and capital resulting from the Common Corporate Cost allocation process and the work programs that support both OM&A and capital is the Total Applicable Overhead Costs. This is a combination of both the centralized Line of Business and the work program costs that support both OM&A and capital.

Task 3. Split Applicable Overhead Costs that support both OM&A and capital

These Total Applicable Overhead Costs (costs associated with activities that support both OM&A and capital and are allocated to the Tx and Dx businesses) need to be split between (a) costs that remain in OM&A, and (b) costs that will be included in the Overhead Capitalization Rate calculation and capitalized. The method employed to do this is to split Total Applicable Overhead Costs between (a) and (b) by multiplying the Total Applicable Overhead Costs by a ratio developed using a 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio.

- **Labour Content-Capital Ratio** - Labour in Tx OM&A versus Labour in Tx capital expenditures OR Labour in Dx OM&A versus Labour in Dx capital expenditures
- **Total Spending-Capital Ratio -** Total Spending on Tx OM&A versus Total Spending on Tx capital expenditures OR Total Spending on Dx OM&A versus Total Spending on Dx capital expenditures

Prior to applying the 50/50 weighting of Labour Content-Capital Ratio and the Total Spending-Capital Ratio to the Shared Service costs that support both OM&A and capital, all Hydro One Accountability Act, 2018 (Bill 2) related costs are removed to ensure no such costs are recovered from capital expenditures for Tx or Dx.

Task 4. Calculate total Capitalized Common Corporate Costs to be recovered from capital expenditures

The total overhead costs to be recovered from capital expenditures is the sum of two components, namely (1) the resulting portion of Total Applicable Overhead Costs after applying the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio in **Task 3** above, and (2) those Shared Service Costs that were flagged as directly and wholly supporting capital expenditures. Any costs that were flagged as OM&A only were excluded from the Overhead Capitalization Rate calculations. The result of this task is the Total Capitalized Common Corporate Costs, i.e., sum of Shared Service and work program costs that will be recovered from capital expenditures.

Task 5. Calculate the Overhead Capitalization Rate

The Overhead Capitalization Rate is derived by dividing the Total Capitalized Common Corporate Costs resulting from **Task 4** by Total Capital Expenditures. The resulting unique Overhead Capitalization Rates for each of the Tx and Dx businesses are then applied to all Tx and Dx capital expenditures, respectively, in order to include these Capitalized Common Corporate Costs as overhead costs on Transmission and Distribution capital expenditures.

Task 6. Application and Monitoring of the Overhead Capitalization Rates

As mentioned above, this entire process is done for Tx and Dx separately to develop unique Tx and Dx Overhead Capitalization Rates. These rates are developed based on Business Plan numbers and other estimates. Hydro One reviews and adjusts the Overhead Capitalization Rates periodically to reflect changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up (in-year) to reflect actual results. Therefore, no adjustments are needed in subsequent years.

6.4 UPDATES TO METHODOLOGY IN 2020

The general methodology for calculating the Overhead Capitalization Rate is the same as past Corporate & Shared Cost Allocation Methodologies, subject to one key enhancement made during the 2020 review.

In past studies the Common Corporate Costs to be split based on the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio were derived by only removing costs for specific Shared Services relating to customer relations, asset management, and operations. These are the Shared Services that were subject to the four-week time study which required employees to track time between each affiliate and projects relating to capital and OM&A. Based on the results of the time study the portion of their time that was spent on capital expenditures was directly included as Capitalized Common Corporate Costs and time spent on OM&A was excluded. All remaining Shared Service costs were split based on the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio.

The enhancement made during the 2020 review involves a more extensive review of activities that should be excluded from the costs split based on the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio. Rather than only directly assigning the results of a time study for specific Shared Services relating to customer relations, asset management, and operations, the 2020 review is providing for the direct assignment of activities across all Shared Services. As such, the review is providing for any Shared Service activity to flag time spent as OM&A only or capital only and either not included in the total Capitalized Common Corporate Costs or directly included. This enhancement has refined the methodology as the determination of directly supporting OM&A or capital is done for each activity rather than just those Lines of Business that participated in the four-week time survey in the past.

In Black & Veatch's Transmission report filed in EB-2019-0082 approximately 69% of Common Corporate Costs were included in the Total Applicable Overhead Costs and split on the 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio. This can be compared to the 55% of Common Corporate Costs included in the Total Applicable Overhead Costs in the current analysis. This change represents a larger percentage of costs directly assigned, which improves the precision of the methodology and is a result of extending the review of time spent as OM&A only or capital only and either to all Shared Service activities.

6.5 CONCLUSIONS AND RESULTS

Black & Veatch believes that Hydro One's current Overhead Capital Rate calculation is appropriate for Hydro One because it aligns with the objectives for which it was designed; to fairly attribute to and recover appropriate overhead costs for capital expenditures. Not all costs can be directly attributed to OM&A or to Capital. The current methodology ascertains which activities wholly and directly relate to each of OM&A and capital and which are overhead supporting both OM&A and capital and a causal link between overhead costs and capital activity exists. When interview or time survey results allowed, certain activities were split between activity directly supporting OM&A,

directly supporting capital, or supported both capital and OM&A. In short, where appropriate, activities were further subdivided into groupings of costs across these three overhead capitalization categories. For instance, a portion of the Planning Line of Business Cost Center relating to Distribution Planning is directly assigned to OM&A only and a portion is directly assigned to Capital only based on time surveys. This detailed level of review results in a method that is accurate and transparent. It also directly couples the review and allocation of Common Corporate Costs with the Overhead Capitalization Rate review providing some cost effectiveness in its implementation (e.g., while a review is being done on understanding the nature of the activity with regard to allocating those costs to Affiliates and businesses, discussions on the activities' support of capital or OM&A can occur). Details on the computations utilized to develop the Overhead Capitalization Rate are provided in Appendix C.

Below are the resulting Overhead Capitalization Rates for the Business Plan year 2023 for both the Tx and Dx businesses.

Table 9 – Overhead Capitalization Rate for Tx and Dx Businesses

OVERHEAD CAPITALIZATION RATE	2023
Transmission Rate	8.00%
Distribution Rate	9.00%

In general, the updates to the methodology employed in the 2020 review resulted in a decrease in the total Common Corporate Costs being recovered through the Overhead Capitalization Rate. This was a result of directly assigning more costs to OM&A only rather than only excluding those costs that were within the historical Time Study groups. This however does not necessarily result in a lower Overhead Capitalization Rate given there are different levels of capital expenditures from which to recover these overhead costs. For the Transmission business the Black & Veatch's Transmission report filed in EB-2019-0082 indicated the Overhead Capitalization Rate was calculated at 8.0% in 2023 which is the same as the rate of 8% **Table 9** above. For the Distribution business the Black & Veatch Distribution report filed in EB-2017-0049 indicated the Overhead Capitalization Rate was calculated at 12% in 2018 which is higher than the 9% calculated and shown in Appendix C of this report.

7 Allocation of Shared Assets

7.1 PURPOSE OF ALLOCATING SHARED ASSETS

In addition to the allocation of Common Corporate Costs it is necessary for compliance with the Affiliate Relationships Code to allocate the use and costs of Shared Assets among Hydro One, its affiliate companies, and between the Tx and Dx businesses. Black & Veatch's objective in reviewing the method of allocating Shared Assets was to ensure that the allocation is reasonable, reflects regulatory principles, does not result in cross-subsidization between businesses, and is consistent with the allocation of Common Corporate Costs.

Hydro One provided Black & Veatch with a list of all Shared Assets which is summarized by asset group and subgroup in **Figure 3** below.

Figure 3 – Types of Shared Assets

ASSET GROUP	ASSET SUBGROUPS
Major Assets	■ Software • Intangibles Software • Computer Equipment • Computer Software ■ Buildings and Telecommunication Equipment • Land • Buildings and Fixtures • Leasehold Improvements • Communication Equipment • System Supervisory Equipment
Minor Assets	■ Aircraft ■ Transportation & Work Equipment ■ Computer Hardware ■ Office Equipment ■ Measurement and Testing ■ Service Equipment- Miscellaneous ■ Service Equipment- Storage ■ Tools

7.2 OVERVIEW OF METHODOLOGY

Most fixed assets are directly purchased by the Transmission or Distribution business and the remaining assets, considered Shared Assets, are held by Hydro One Networks. These assets are allocated to Hydro One, its Affiliates, and the Tx and Dx businesses. The percentage of Shared Assets that are not allocated to Tx or Dx are utilized to develop applicable transfer prices which are costs charged by Hydro One Networks Inc. to its Affiliates for the use of these Shared Assets. The revenues received by Hydro One Networks Inc. from these charges are used to offset the revenue requirements for the Transmission and Distribution businesses associated with the Shared Assets.

The general process employed to conduct this review was to gain an understanding of the particular nature of the Shared Assets and the use of the Shared Assets by Hydro One, its Affiliates, and the Tx and Dx businesses. With this understanding, allocation options were reviewed and decided upon to allocate the costs of these Shared Assets among Hydro One, its Affiliates, and the Tx and Dx businesses. The results of this allocation support the development of the Tx and Dx business revenue requirements and transfer pricing for Hydro One's affiliates.

Task 1. Review the nature and use of the Shared Assets

The asset subgroups listed in **Figure 3** are comprised of dozens of fixed assets. These fixed assets are reviewed to gain an understanding as to the nature of the Shared Asset, the support the Shared Asset provides to the Shared Services, and support provided to particular businesses. This understanding was gained by reviewing documentation and interviews with Hydro One personnel.

Task 2. Review and choose an allocation methodology for the Shared Assets

Black & Veatch selected an allocation methodology and specific cost drivers for each fixed asset based on applying the cost allocation principles discussed in Section 4, its expertise and experience in performing cost allocation studies, industry practices, and consultations with Hydro One as to the nature of each fixed asset and availability of information.

Major Assets

- **Software -** Most of the software included in Shared Assets is enterprise software and Hydro One's SAP system also known as Cornerstone, an enterprise-wide system to support work management, asset management, human resources, financial and other functions. The cost of this software was allocated using cost drivers that reflect the activities supported. For example, capitalized software implementation costs related to Human Resources was allocated based on headcount. Further, some software was directly assigned to one of the businesses (e.g., direct assignment of the customer information system to the Dx business).

- **Buildings and Telecommunications Equipment -** Each asset included in Buildings and Telecommunications Shared Assets was allocated using one of the following methods:
    - **Specific estimation for a building** - For example, the Sudbury Service Centre has estimated usage of Transmission-20% and Distribution-80%.
    - **Direct assignment based on type of usage** - For example, Hydro One summarized Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2014-1st quarter 2020 and determined that Fleet usage was Transmission- 32% and Distribution- 67%; therefore the costs for buildings used for Fleet were allocated using these percentages.
    - **Cost Drivers** - For example, buildings used to manage both Distribution and Transmission projects are allocated using the cost driver OM&A and capital expenditures, developed as part of the Allocation of Common Corporate Costs methodology.

Minor Assets

Black & Veatch reviewed the lists of individual items and determined that the following allocations are appropriate:

- **Aircraft** – Includes helicopter and supporting components. Usage was based on an analysis of time charges (which are recorded to time sheets concurrently with usage) for years 2014 - 1st quarter 2020.
- **Transportation & Work Equipment** – Includes primary vehicles and associated equipment. Allocated using the cost driver "Fleet", which represents Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2014 - 1st quarter 2020.
- **Computer Hardware** – Includes Laptops, Desktops, Network Equipment, Printers, etc. Allocated using the cost driver Headcount.
- **Office Equipment** – Includes office furniture and other office equipment. Allocated using the cost driver Headcount.
- **Measurement and Testing Equipment** – Includes testing and measurement equipment and tools used for Distribution. Directly assigned to Distribution.
- **Service Equipment- Storage** – Includes Waste Storage and Other Storage equipment. Allocated using the cost driver based on total OM&A expenditures and capital expenditures for Tx and Dx businesses.

- **Service Equipment - Miscellaneous** – Includes miscellaneous equipment. Allocated using Total Common Corporate Costs cost driver, developed as part of the Common Corporate Cost allocation methodology.
- **Tools** – Includes Rental tools. Allocated Distribution-20% / Transmission-80% reflecting estimated usage based on information as to which business units are renting the tools.

Task 3. Populated cost drivers

The purpose of this task was to determine the values of each cost driver that are attributable to Hydro One, its Affiliates, and the Tx and Dx businesses in order to distribute the costs of each activity. The majority of the cost drivers were also used in the allocation of Common Corporate Costs so they were already populated during that process (see Task 8 within section 5.5 – Common Corporate Cost Allocation Review Process). Outside of the cost drivers utilized from the Common Corporate Costs Allocation allocations factors were developed for aircraft, fleet, total Common Corporate Costs (outcome of Common Corporate Costs Allocation), central maintenance services, and field offices.

Task 4. Allocated Shared Asset costs to the businesses

The next step in the Shared Asset allocation methodology is to multiply the cost for each fixed asset by the chosen Cost Driver resulting in an allocation of total Shared Asset costs among Hydro One, its Affiliates, and the Tx and Dx business. The Shared Assets allocated to the Tx and Dx businesses are included in the revenue requirement calculation for those businesses.

Task 5. Calculate transfer price charge rates for Affiliates

The full costs of the Shared Assets are allocated to Hydro One, its Affiliates, and the Tx and Dx businesses. The percentage of Shared Asset costs that is not allocated to the Transmission or Distribution businesses is utilized to develop applicable transfer prices which are costs charged to Affiliates for the use of these Shared Assets and applied as an offset to the revenue requirements for the Transmission and Distribution businesses that are associated with these Shared Assets.

Black & Veatch understands that the revenue requirements calculated for the Tx and Dx businesses will initially include 100% of revenue requirement associated with all of the Shared Assets. However, the other revenues received by Hydro One Networks Inc. by means of the transfer pricing are applied as a reduction to the revenue requirements that are ultimately requested for recovery through Transmission and Distribution rates.

The transfer price charge rates represent the usage of the Shared Assets by Hydro One's affiliate businesses. The approach to developing the transfer price charge rates is as follows:

- The portion of each asset that should be allocated to Hydro One and each Affiliate based on the appropriate cost driver was determined (result of Task 4 above).
- A revenue requirement was developed for the Shared Assets subgroup based on the components of the revenue requirement (return on debt, return on equity, taxes, and depreciation expense) for the Tx and Dx businesses for each Shared Asset subgroup.
- This revenue requirement for each Shared Assets subgroup was multiplied by the portion of the Shared Assets subgroup allocated to each affiliate with transfer pricing.
- These resulting dollar amounts were summed for each Shared Asset subgroup for each Affiliate with transfer pricing to develop the total transfer price.

7.3 UPDATES TO METHODOLOGY IN 2020

The general methodology for allocating Shared Assets and developing the transfer pricing is the same as past Corporate & Shared Cost Allocation Methodologies. The 2020 review included a detailed review of the Shared Assets with a particular emphasis on reviewing documentation and gathering details from Hydro One personnel on the 30 capital assets that made up 90% of the total capital costs. Further, the methods employed in allocating Shared Assets is in alignment with the allocation of Common Corporate Costs; where Shared Services and Shared Assets are providing a similar service the allocation factor was the same across the two methodologies.

As noted above in Section 5.4.3 the three-factor allocation driver based on Capital, Labour, and Revenue was utilized to reflect the fact that the effort associated with a certain activity relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity or by any particular allocation factor. This three-factor allocation driver was applied to computer software and enterprise systems that relate to the overall operations and enterprise applications that utilized by Hydro One, its Affiliates, and the Tx and Dx businesses. Given the nature of these Shared Assets and availability of information the use of the three-factor allocation driver based on Capital, Labour, and Revenue is appropriate for the allocation of these Shared Assets and results in a methodology that is in alignment with regulatory practices.

7.4 CONCLUSIONS AND RESULTS

Black & Veatch believes that Hydro One's current allocation of Shared Assets is appropriate for Hydro One because it aligns with the objectives for which it was designed; to fairly attribute and recover the Shared Assets from Hydro One, its Affiliates, and the Tx and Dx businesses in a manner consistent with regulatory practice and the requirements of the Affiliate Relationships Code. Hydro One's other affiliated businesses which is used to develop any applicable transfer pricing for those Affiliates.

Table 10 below provides the resulting allocation of Shared Asset values as of March 31, 2020 for the Transmission and Distribution businesses. In addition, this table provides a column with "Other" which represents the allocations to Hydro One's other affiliated businesses which is used to develop any applicable transfer pricing for those Affiliates.

Table 10 - Allocation of Shared Assets to Tx and Dx Businesses

Type	Asset Value	Transmission	Distribution	Other	Tx %	Dx %	Other %
Major Assets							
Buildings and Fixtures	$ 44.60	$ 19.96	$ 24.29	$ 0.35	44.75%	54.46%	0.79%
Communication equipm	$ 12.72	$ 6.41	$ 6.20	$ 0.11	50.38%	48.77%	0.85%
Computer Equip Major	$ 19.37	$ 7.48	$ 11.72	$ 0.16	38.63%	60.53%	0.83%
Computer Software	$ 144.25	$ 63.20	$ 76.12	$ 4.93	43.81%	52.77%	3.42%
Intangible-ContCap	$ 12.01	$ 11.16	$ 0.85	$ -	92.95%	7.05%	0.00%
Intangibles Software	$ 92.37	$ 23.80	$ 67.57	$ 1.00	25.76%	73.16%	1.08%
Land	$ 61.97	$ 29.41	$ 32.56	$ -	47.46%	52.54%	0.00%
Leasehold improvemnt	$ 3.18	$ 1.10	$ 2.08	$ -	34.61%	65.39%	0.00%
Syst supervisry equp	$ 0.36	$ 0.02	$ 0.34	$ 0.00	6.04%	93.65%	0.32%
Subtotal - Major Assets	$ 390.82	$ 162.54	$ 221.73	$ 6.55	41.59%	56.73%	1.68%
Minor Assets							
Transportation equip	$ 167.39	$ 54.15	$ 113.24	$ -	32.35%	67.65%	0.00%
Power operated equip	$ 88.97	$ 28.78	$ 60.19	$ -	32.35%	67.65%	0.00%
Aircraft & Railway	$ 5.48	$ 4.12	$ 1.36	$ -	75.18%	24.82%	0.00%
Comp Equip / Telecom	$ 8.07	$ 3.81	$ 4.06	$ 0.20	47.23%	50.30%	2.47%
Tools,shop,garag equ	$ 2.39	$ 1.29	$ 1.10	$ -	54.09%	45.91%	0.00%
Office furnitre Equp	$ 2.62	$ 1.27	$ 1.35	$ -	48.42%	51.58%	0.00%
Measurement & testin	$ 1.19	$ -	$ 1.19	$ -	0.00%	100.00%	0.00%
Misc. service equipm	$ 0.15	$ 0.08	$ 0.07	$ -	54.09%	45.91%	0.00%
Stores equipment	$ 0.18	$ 0.10	$ 0.08	$ 0.00	53.87%	45.72%	0.41%
Subtotal - Minor Assets	$ 276.45	$ 93.61	$ 182.64	$ 0.20	33.86%	66.07%	0.07%
Total - All Shared Assets	**$ 667.27**	**$ 256.15**	**$ 404.37**	**$ 6.75**	**38.39%**	**60.60%**	**1.01%**

There are no material changes to the outcome of the Shared Asset allocations to the Transmission and Distribution businesses. The current analysis is resulting in 38.39% to Tx and 60.60% to Dx as shown on **Table 10**; compared to the 38.3% to Tx and 61.7% to Dx provided in the summary Table 3 within Black & Veatch's Transmission report filed in EB-2019-082.

Appendix A – Past Affiliate Cost Allocation Reviews and Reports

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by Black & Veatch with subsequent reports issued, as follows:

Table 11 - History of Black & Veatch's Common Corporate Cost Reviews and Reports

BLACK & VEATCH REVIEW	BLACK & VEATCH REPORT
2006 Review	*Report on Implementation of Common Corporate Costs Methodology* dated May 31, 2006
2008 Review	*Report on Implementation of Common Corporate Costs Methodology* dated September 10, 2008
2009 Review	*Report on Shared Services Costs Methodology* dated June 29, 2009
2010 Review	*Report on Shared Services Costs Methodology – 2011* dated February 26, 2010
2012 Review	*Review of Shared Services Cost Allocation (Transmission) – 2012* dated February 1, 2012
2013 Review	*Review of Allocation of Common Corporate Costs (Distribution) – 2013* dated September 19, 2013
2014 Review	*Review of Allocation of Common Corporate Costs (Transmission) – 2014* dated March 17, 2014
2015 Review	*Review of Allocation of Common Corporate Costs (Transmission)- 2015 dated May 4, 2016*
2016 Review	*Review of Allocation of Common Corporate Costs (Distribution) – 2016* dated December 21, 2016
2018 Review	*Review of Allocation of Common Corporate Costs (Transmission)- 2019 dated January 31, 2019*

Table 12 - History of Black & Veatch's Shared Asset Allocation Reviews and Reports

BLACK & VEATCH REVIEW/ASSET VALUES	BLACK & VEATCH REPORT
2006 Review	*Report on Common Assets Methodology 2006* dated May 31, 2006
2008 Review	*Report on Common Assets Methodology 2008* dated September 10, 2008
2009 Review	*Report on Common Assets Allocation- 2009* dated June 29, 2009
2009 Review	*Report on Common Assets Allocation (Transmission) - 2010* dated February 26, 2010
2011 Review	*Report on Shared Assets Allocation (Transmission) 2012* dated February 1, 2012
2013 Review	*Report on Shared Assets Allocation (Distribution) 2013* dated September 19, 2013
2014 Review	*Report on Shared Assets Allocation (Transmission) 2013* dated March 17, 2014
2015 Review	*Report on Shared Assets Allocation (Transmission) 2015* dated May 4, 2016
2016 Review	*Report on Shared Assets Allocation (Distribution) 2016* dated December 21, 2016
2018 Review	*Review of Shared Assets Allocation (Transmission)– 2019* dated January 31, 2019

Table 13 - History of Black & Veatch's Overhead Capitalization Reviews and Reports

BLACK & VEATCH REVIEW	BLACK & VEATCH REPORT
2006 Review	*Transmission Overhead Capitalization Rate Method* dated April 30, 2006
2008 Review	*Implementation of Transmission Overhead Rate Capitalization Methodology – 2009 / 2010* dated September 10, 2008
2009 Review	*Review of Overhead Capitalization Rates* dated June 29, 2009
2009 Review	*Review of Overhead Capitalization Rates (Transmission) – 2011/2012* dated February 26, 2010
2011 Review	*Review of Overhead Capitalization Rates (Transmission)– 2013-2014* dated February 1, 2012
2013 Review	*Review of Overhead Capitalization Rates (Distribution)– 2015-2019* dated September 19, 2013
2013 Review	*Review of Overhead Capitalization Rates (Transmission)– 2015-2016* dated March 17, 2014
2015 Review	*Review of Overhead Capitalization Rates (Transmission)– 2017-2018* dated May 4, 2016
2016 Review	*Review of Overhead Capitalization Rates (Distribution)– 2018-2022* dated December 21, 2016
2018 Review	*Review of Overhead Capitalization Rates (Transmission)– 2019* dated January 31. 2019

Appendix B – Common Corporate Costs Allocation - Details on the Lines of Business

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
Hydro One Inc. Corporate Office (HOI)		
Board of Directors	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary.	Costs are allocated using the results of a time survey and the capital, labour, revenue allocator.
Ombudsman	The Ombudsman Office commenced activity following the Initial Public Offering, in order to address complaints escalated from the Customer Service. Prior to that, the Province of Ontario's Ombudsman had authority to investigate issues related to Hydro One customers.	Labour costs are allocated using the results of a time survey. Non-Labour costs are allocated based on labour costs.
President-CEO Office	Leadership of the staff of the Corporation to ensure that their culture and behaviours lead to achievement of its strategic objectives. Develops and updates strategy and establishes performance targets to assess progress towards the goals and objectives defined by the strategy.	Labour costs are allocated using the results of a time survey, the capital, labour, revenue allocator, and the resulting allocation of the Board of Directors line of business. Non-labour costs are allocated based on labour costs.
Customer & Corp Affairs		
Corp Affairs	The Communications team supports external and internal communications initiatives, including traditional media and social media. The team is also accountable for customer education and safety programs, corporate reputation, media relations, community investment, employee communications, and web communications for Hydro One's corporate website. The External Relations team also manages the company's relationship with key external stakeholders, such as the government, Ministry of Environment, energy regulators, elected officials, municipal associations, industry associations, and energy sector stakeholders, in order to address customer needs. The team is responsible	Labour and non-labour costs are allocated using the results of a time survey, the capital, labour, revenue allocator, and based on headcount.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	for providing various lines of business with public affairs and community relations advice during the environmental, legal and regulatory approvals phases of a project to ensure requirements are met and public consultations are conducted. The team leads public consultation, environmental assessments, and community engagement functions in support of new development projects, maintenance and forestry programs.	
Corp Sustainability	Work on behalf of entire company to help develop and implement sustainability, including Social and Governance initiatives. Work internally on policies and programs to ensure they are supporting sustainability goals, setting goals and reviewing these - data governance and non-financial data to ensure the right data and governance procedures are in place.	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Cust Service	Activities and functions include all touch points with customers. These touch points include billing, account management for large customers, support for self-service tools. Activities also include the long-term strategy and planning for Hydro One's interaction with customers.	Labour costs are allocated using the results of a time survey, kilometers of lines (for Tx key account management), capital expenditures, as well as the capital, labour, revenue allocator. Some direct assignment of non-labour costs to Dx and Tx and non-labour costs allocated based on labour costs.
Ext Relations	Three groups (1) Community Relations – almost entirely facilitating capital maintenance and forestry programs – people in between the company and the physical footprint of the operations. Less of communication element but really an integration of supporting project success. Very integrated project and runs through asset manager, planning departments and environment. (2) Government Relations – enterprise roll with a focus on high level policy implications for the successful implementation of projects and relationship between strategic plans and government policy.	Labour costs are allocated using the results of a time survey, work program costs, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	(3) Policy and Partnerships – public policy and stakeholder relations – high amount of interaction and engagement with various organizations across industry and broader advocacy groups across Ontario.	
Indigenous Relations	Develops and maintains mutually beneficial relationships with Indigenous communities serviced by Hydro One. The team promotes effective relationships with Indigenous customers and communities and promotes business and workforce development for Indigenous peoples. The team also conducts consultations with Indigenous peoples and communities in the early stages of, and throughout, projects or other activities that may impact their Aboriginal rights and/or treaty rights.	Labour costs are allocated based on headcount, OM&A expenditures, and capital expenditures. Non-labour costs are allocated based on labour costs.
Finance		
Audit	Provides assurance that internal controls continue to operate effectively, identification and recommendations for areas where controls can break down or need improvement to meet corporate objectives.	Labour costs are allocated using the results of a time survey, work program costs, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs, the results of a time survey, work program costs, as well as the Capital, Labour, Revenue allocator.
Business Analysis	Business Analysis provides financial analysis and analytics for senior leadership team (net income graphs and bridges), input that goes into Board Material, and investor relations and executive leadership team. Customers of these services are primarily Hydro One Networks – some of the consolidated work supports HOL and some supports investors and the Board.	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
CFO	Provide Hydro One and subsidiaries with strategic review and approval for all financial and investment decisions. Review policies and procedures, treasury operations and tax planning, financial control and reporting.	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Corp Controller	Primarily responsible for corporate	Labour costs are allocated using the

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	accounting, internal reporting, and external consolidated reporting to stakeholders, including Hydro One's regulator, the Ontario Energy Board. Supporting these are the back-office accounting and payroll functions, outsourced to Inergi. The Corporate Controller is also accountable for financial master data management, capital accounting, and the expense management policy and process.	results of a time survey, headcount, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs, the results of a time survey, headcount, capital expenditures, and using the capital, labour, revenue allocator.
Corp Development	Develops the strategy by generating innovative new business opportunities. Responsible for the planning and execution of Hydro One's objectives through identifying and acquiring target companies in line with Hydro One's strategic plan and growth strategy. Costs are directly assigned to Shareholder and non-regulated affiliates.	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labor costs and using the results of a time survey.
Data Governance	Tasked with improving confidence in data, across Hydro One's Lines of Business through the delivery of an enterprise-wide Data Governance Framework.	Labour costs are allocated using the resulting allocation from the ISD line of business and using the capital, labour, revenue allocator. Non-labour costs are allocated using the labour costs.
Facility & Real Estate	Manage and acquire rights of way and easements; manage property taxes; manage SLU revenue programs; manage Employee Relocation Program.	Labour costs are allocated using the results of a time survey and based on work program costs. Non-labour costs are allocated based on labour costs.
Invest Relations	Investor Relations commenced activity following the Initial Public Offering, in order to communicate with Shareholders and potential investors and address their concerns. Costs are directly assigned to Shareholder only.	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labour costs.
Outsourcing	Contract governance for Inergi IT, Finance and Accounting, Payroll, and Supply Chain, as well as supporting BGIS. Work on new contract terms, pricing, and contractor governance.	Labour costs are allocated using BGIS contract amounts, headcount, work program costs, capital expenditures, the results of a time survey, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Pension	Pension fund contributions.	Non-labour costs are allocated using the defined contributions headcount.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
Risk	The Risk office creates an enterprise-wide comprehensive and uniform approach to anticipate, identify, prioritize, measure, treat and report on key business risks impacting the organization. It puts in place the policies, common processes, competencies, accountabilities, reporting and enabling technology to execute that approach successfully.	Labour costs are allocated using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Strategic Finance	3 primary functions: (1) Long Term Financial Planning: extends to both regulated and consolidating non-regulated segments of Hydro One (2) Decision Support Function: Oversees entire business case/project approval process for capital-based projects – facilitating this entire process and providing financial support. (3) Productivity/Governance Function: Support productivity achievement and calibrating and validating new initiatives throughout the Company.	Labour costs are allocated based on capital expenditures, the results of a time survey, and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Strategy & Innovation	The mandate of the Strategy & Growth team is to support the non-regulated affiliates growth with unregulated electrification business growth opportunities.	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labour costs.
SVP Finance	Supports regulatory filings, tax group, strategic finance, data governance across the group with a significant focus on regulated businesses. Remaining activities support undertakings by the holding companies and time on the Board of Directors for Hydro One Remotes.	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Tax	Meet internal and external tax compliance requirements and reduce overall corporate tax liability through tax planning for current and new businesses, acquisitions and dispositions, special projects, tax compliance (including income tax, HST, and DRC returns for all entities), tax accounting, and	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labour costs.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	government tax audits.	
Treasury	Debt and equity issuance, capital structure management and oversight of Finance and Treasury function.	Labour costs are allocated using the capital, labour, revenue allocator. Non-labour costs are allocated using the results of a time survey and based on labour costs.
Human Resources		
HR-Change Management	The Change Management team supports (1) companywide change management – big broad corporate initiates company values, rolling out new strategies and (2)change management focused on affiliates/lines of business when they are undertaking major projects. The Diversity & Inclusion team, develops and manages Hydro One's diversity and inclusion strategies, plans, programs and policies.	Labour costs are allocated based on headcount and capital expenditures. Non-labour costs are allocated based on labour costs.
HR-Labour Relations	HR Operations and Corporate Groups that provides frontline support to labour groups – Tx, Dx, telecom, remotes, etc. Support includes discipline process, compensation reviews, workforce planning, reviewing labour risk for operations, organizational design, labour contract provisions, etc. This support is provided for employee/employer relations from the first line works to the executive level.	Labour costs are allocated based on the headcount, union employee headcount, and using the resulting allocation of the Board of Directors line of business, the results of a time survey, and the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
HR-Talent Management	Primarily employee-related services, including administer compensation & benefits programs; decision support for businesses; talent management (hiring, succession, development, coaching; high potential employee assessments); recruitment (diversity programs, grad program, student/co-op, line of business resourcing); data administration; consulting support to LOBs and corporate functions; VP Human Resources.	Labour costs are allocated based on headcount. Non-labour costs are allocated using labour costs.
HR-Total Rewards	Manage the Pensions (administration of plan, assisting to responding to questions notifying enrollments of new members, etc.). Compensation (job evaluation, salary recommendation, compensation	Labour costs are allocated based on headcount. Non-labour costs are allocated based on labour costs and headcount.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	reviews for management, merit increase, base wage increases, short term and long-term incentives, and collective bargaining units). Health and Wellness Benefits (core health and dental programs, Disability Management, and oversee Health and Wellness training and support).	
HR-Work force Acquisition &Support Centre	Service Center is primarily responding for employee inquires (pensions, benefits, etc.) for all employees across Hydro One except for casual workforce Workforce Acquisition (WAS Team) which focuses on casual workforce and are fully recoverable through work programs. HR Technology supports all HR tools and programs including recruiting, talent management, compensation, etc. as well as supporting entire HR functions and modules within the system that relate to recruiting, compensation, etc.	Labour costs are allocated based on headcount. Non-labour costs are allocated using labour costs.
Information Solutions Division		
Information Solutions Division	The Information Services Division is an integration of business process, information, applications, infrastructure, network and security. The Technology team is responsible for information systems architecture, information security, project delivery and management of information services. The Security Operations team provides services for personnel and physical security, business continuity management, IT security, and compliance sustainment.	Labour costs are allocated based on fixed assets & construction in progress as well as using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.
Legal & Secretariat		
Corporate Secretariat	Provide direction and analysis in areas of: Board and Committee(s); Office of Chair and Board members; Code of Business Conduct; Community Citizenship; Freedom of Information and Privacy, Corporate Archives, Corporate Records, Corporate Secretariat. Oversee and support Law, Regulatory and Corporate	Labour costs are allocated using the results of a time survey and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	Secretariat General Counsel functions.	
General Counsel	The law group provides legal and strategic advice across all the entities, as well as record management and privacy services. Services and support as required are provided to both capital- and maintenance-related work.	Labour costs are allocated based on work program costs, the resulting allocation of the Board of Directors line of business, and using the capital, labour, revenue allocator. Non-labour costs are allocated based on labour costs and using the capital, labour, revenue allocator.
Regulatory Affairs	Coordinate applications with OEB; compliance with OEB orders; design and implement regulatory policy; manage relationship with OEB. Tasks include: cost allocation and rate design for regulated Tx and Dx, especially rate structures and rates for Tx and Dx tariffs; implement approved rates; support transmitters' representative on IESO Technical Panel; manage settlement.	Labour costs are allocated using the results of a time survey. Non-labour costs are allocated based on labour costs and using direct non-labour assignment.
Operations		
COO	The COO office is responsible for the day-to-day operations and success of the Tx and Dx - accountable for end-to-end delivery of Hydro One's work and improving the efficiency and effectiveness of the Companies including both time and effort on sustainment activities and capital expenditures.	Labour costs are allocated using work program costs. Non-labour costs are allocated using labour costs.
Planning	Develop and commit prioritized, defensible transmission and distribution development plans, consistent with corporate strategy, to meet government policy, OPA plans, customer needs, regulatory requirements and industry standards. Conduct Regional Infrastructure Planning to meet OEB requirements and to develop regional plans to meet regional supply needs.	Labour costs are allocated using the results of a time survey and based on work program costs. Non-labour costs are allocated based on labour costs and fixed assets & construction in progress.
System Control	The System Ops team monitors and operates the Ontario electricity grid 24/7 using distribution and transmission grid teams. These teams do scheduling, coordinating of planned outages, and real time management of the electricity	Labour costs are allocated using results of a time survey and kilometers of lines. Non-labour costs are allocated based on labour costs.

LINE OF BUSINESS	DESCRIPTION OF ACTIVITIES	METHOD OF ALLOCATION
	network. There is also a systems operation support team, which provides support to the grid team, including training, engineering support, etc.	

Appendix C - Overhead Capitalization Rate Calculation

This appendix provides details on the method used to compute the Overhead Capitalization Rate, providing specific descriptions of each calculation presented in **Figure 4** on page 58.

Capital Expenditures (rows 1-7)

Total Capital Expenditures represents the cost of Capital Expenditures and is the total cost of Capital Expenditures to which the Overhead Capitalization Rate is applied. Total Capital Expenditures equals total spending for Capital Expenditures reported for financial accounting, adjusted as follows:

- Minor Fixed Assets (such as vehicles) and Interest Capitalized are removed because they require little Shared Service support.
- Capitalized Overhead is removed to avoid redundancy.
- Capital Contributions by Customers are added because the Shared Services support required is related to gross capital cost, not net capital cost.
- Removal Costs are added because removal of capital assets requires Shared Services support.

Total OM&A (rows 8-10)

Total OM&A is used in computing the portion of Total Spending (capital plus OM&A) related to capital (rows 21-24). The amounts are based on the Business Plan, with adjustments to remove those Work Program costs which are included in Applicable Cost for OH Cap Labour/Spend Allocation (Row 12).

Applicable Cost for OH Cap Labour/Spend Allocation (rows 11-16)

Applicable Cost for OH Cap Labour/Spend Allocation (row 16) represents the combination of both the centralized Line of Business and the work program costs that support both OM&A and capital and are split between (a) costs that remain OM&A and (b) those that will be included in the overhead capitalization rate calculation and capitalized. The calculation of Applicable Cost for OH Cap Labour/Spend Allocation (row 16) is the combination of the below items:

- Total Common Corporate Costs resulting from the Common Corporate OM&A Cost allocation methodology.
- In addition to the Lines of Businesses included and reviewed in the Common Corporate OM&A Cost allocation there are some work program costs that provide Shared Services. These relate to IT sustainment, telecommunication service and equipment costs, and operation center and

headquarters costs; and are included. (row 12)

- Directly assigned Capital total Shared Services are removed because the capitalization of those costs was determined in the Common OM&A Cost allocation. (row 13)
- Directly assigned OM&A total from the Common Corporate OM&A Cost allocation are removed because it was determined that these costs relate directly to OM&A. (row 14)
- Any Hydro One Accountability Act, 2018 (Bill 2) costs that are included in the Common Corporate OM&A Cost allocation are removed. (row 15)

The resulting amount (row 16) represents the combination of both the centralized Line of Business and the work program costs that support both OM&A and capital and are split between (a) costs that remain OM&A and (b) those that will be included in the overhead capitalization rate calculation and capitalized.

Labour Content-Capital Ratio (rows 17-20)

Labour Content-Capital Ratio is derived by summing total work program labour costs within OM&A and total labour costs within Capital Expenditures; then dividing the total labour for Capital Expenditures into this sum; resulting in the portion of Total Labour relative to Capital Expenditures Labour (Row 20)

Total Spending-Capital Ratio (rows 21-24)

Total Spending-Capital Ratio is derived by summing total work program OM&A costs and total Capital Expenditures costs; then dividing the total Capital Expenditures costs into this sum; resulting in the portion of Total Costs relative to Capital Expenditures Costs (Row 24).

Percentage to be Capitalized (rows 25-27)

The percentage of Applicable Cost for OH Cap Labour/Spend Allocation to be capitalized is the average of Labor Content-Capital Ratio (from row 20) and Total Spending Capital Ratio (from row 24), using the appropriate weights (rows 25-26). This percentage is multiplied by the Applicable Cost for OH Cap Labour/Spend Allocation (row 28) to compute Capitalized Portion of Applicable Cost for OH Cap Labour/Spend Allocation (row 29).

Capitalized Common Corporate Costs (rows 29-31)

Capitalized Overhead Coast (row 31) represents the amount of Shared Services work program costs that should be capitalized through an overhead charge to Capital Expenditures projects. The Total Capitalized Common Corporate Costs is derived by summing the Capitalized Portion of Applicable Cost for OH Cap Labour/Spend Allocation (row 29) and the directly assigned Capital total Shared

Services excluding Hydro One Accountability Act, 2018 (Bill 2) costs that were determined in the Common Corporate OM&A Cost Allocation methodology (row 30).

Overhead Capitalization Rate (rows 31-33)

The Overhead Capitalization Rate (row 33) is derived by dividing the total Capitalized Common Corporate Costs (row 31) by Total Capital Expenditures (row 32).

Figure 4 – Overhead Capitalization Illustrative Calculation

	($ millions)	Tx 2023	Dx 2023
1	Capital Expenditures	1,434.0	991.2
2	Less: Minor fixed assets	(29.5)	(57.7)
3	Less: Capitalized overhead	(118.1)	(89.9)
4	Less: Capitalized interest	(36.4)	(7.6)
5	Add: Capital contributions	100.4	70.4
6	Add: Removal costs	61.2	77.5
7	Total CapExp	1,411.6	983.9
8	Total OM&A (direct w ork program / SDOC)	332.6	519.6
9	Less: Work programs applicable for overhead cap	(67.5)	(86.1)
10	Total OM&A	265.0	433.5
	Capitalized Common Corporate Costs		
11	Total Common Corporate Costs per CCCM	134.8	144.0
12	Work programs applicable for overhead cap	67.5	86.1
	Less: Non-applicable CCC for OH Cap		
13	Directly Assigned Capital CCC Excl. Bill 2	(31.0)	(13.5)
14	OM&A Only Costs	(57.8)	(100.1)
15	Bill 2 Costs for Capitalizable OH Teams	(4.0)	(4.3)
16	Applicable Cost for OH Cap Labour/Spend Allocation	109.5	112.2
	Development of OH Cap Labour/Spend Allocation		
	Portion capitalized based on labour content:		
17	Labour in OM&A	137.7	238.8
18	Labour in capexp	412.8	478.4
19	Total	550.4	717.1
20	% capexp	75.0%	66.7%
	Portion capitalized based on total spending:		
21	OM&A	265.0	433.5
22	Capexp	1,411.6	983.9
23	Total	1,676.6	1,417.4
24	% capexp	84.2%	69.4%
	Weighting:		
25	Labour content	50.0%	50.0%
26	Total spending	50.0%	50.0%
27	Portion capitalized based on w eighting of tw o methods	79.6%	68.1%
28	Applicable Cost for OH Cap Labour/Spend Allocation	109.5	112.2
29	Capitalized Portion of Applicable CCC	87.2	76.4
30	Directly Assigned Capital CCC Excl. Bill 2	31.0	13.5
31	**Total CCC Capital Overheads**	**118.1**	**89.9**
32	Total CapExp	1,411.6	983.9
33	Calculated overhead capitalization rate	8.37%	9.14%
34	Rounded	8.00%	9.00%

COST OF EXTERNAL WORK

1.0 SUMMARY & PROGRAM INTRODUCTION

Remotes performs a small amount of external work for other parties. Descriptions of the external work provided are discussed in Exhibit D Tab 1, Schedule 1. Costs related to external work are shown in Table 1. Revenues from external work are an offset to the revenue requirement and are discussed in Exhibit F, Tab 3, Schedule 1.

TEST EXPENDITURE FORECAST LEVEL

Remotes develops forecast expenditure levels for the Cost of External Work program based on the expected external revenue and cost to incur the work noted. Table 1 below sets out Remotes' planned expenditures for the 2023 test year, along with forecast and actual spending levels for the bridge and historical years, for the Cost of External Work program, followed by supporting variance explanations.

Table 1 - Costs Related to External, Unregulated Work (*in thousands $*)

Category	OEB-Approved	Historical (Actuals)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
External Work	135	589	691	490	731	238	212

2023 Test Year vs. 2018 OEB-Approved (last OEB-Approved)

- forecasted expenditures are $77k higher primarily due to higher ESA requests.

2023 Test Year vs. 2021 Actuals (most recent actuals)

- forecasted expenditures are $519k lower primarily due to fewer streetlight maintenance projects and reallocation of other costs to Miscellaneous General Expenses.

2023 Test Year vs. 2022 Bridge Year

- forecasted expenditures are $26k lower with no significant variances noted.

2022 Bridge Year vs. 2021 Actuals (most recent actuals)

- forecasted expenditures are $493k lower primarily due to fewer streetlight maintenance projects and reallocation of other costs to Miscellaneous General Expenses.

2018 Actuals vs 2018 OEB-Approved

- actuals expenditures were $454k higher primarily due to higher streetlight maintenance programs, backup generation report and Fort Severn micro-grid project.

COSTING OF WORK

1.0 OVERVIEW

Remotes' work program costs are comprised primarily of expenditures associated with labour, equipment, material acquisition and sundry. Consistent with common industry practice, trade labour and equipment hours are distributed directly to benefiting programs and projects by weekly time-entry. Standard hourly labour and equipment rates are then used to convert the reported hours into costs. Both labour and equipment rates are "fully loaded" to ensure that all associated support costs required to deploy resources and equipment are accurately and cost effectively distributed to the benefiting work.

In terms of material and contract costs, a material surcharge is included in this cost category to capture material and contract services procurement costs benefiting the program or project. In the case of distribution capital projects and external sales, a freight surcharge is also included to distribute the freight costs associated with the winter road delivery of distribution line materials into the remote communities.

As fourteen of the communities Remotes serves are not accessible by year-round road, staff, equipment, and cargo are transported to the communities by aircraft. Remotes contracts out the passenger and cargo transportation services. Flight costs are charged to the project that the personnel are working on. Cost efficiencies achieved by co-ordination of work crew scheduling are captured whenever possible.

Remotes staff most often stay several days at a time in the company's staff house in the remote community in which they are working. To efficiently reflect the cost of food to direct work, food expense is allocated to all projects in which there are labour hours incurred by trade and technical staff. This cost is implicit in the labour rate ("fully loaded") and is $8 per hour in the test year.

In terms of estimating and costing capital work, there may be circumstances when removal costs or customer contributions need to be separately identified. The cost of removal work is accounted for as Depreciation and Amortization and customer contributions are netted against the gross capital costs. Capital work also receives a monthly charge for its share of Corporate Common Functions and Services, overhead costs and capitalized interest where applicable.

2.0 PROJECT / PROGRAM MAJOR COST CATEGORIES

2.1 STANDARD LABOUR RATES

On an annual basis, Remotes' standard labour rates are derived based on information gathered through the annual budgeting process. Resource budgets for each major resource category are calculated and categorized into three basic cost components; forecast billable (direct charged) hours, forecast non-billable hours, and forecast non-billable expenses. Total payroll costs include allowances (as per negotiated contracts), company benefits, government obligations and contractual time away from work (vacation, statutory holidays, sick leave) along with assigned Remotes' administrative costs. Total payable costs are then divided by the forecast billable hours, to create the Remotes standard labour rates. The cost elements embedded in the standard rate are illustrated in Table 1 and explained in the pages following, using the Remotes Technician rate as an example.

Table 1 - Remote Communities Technician (Regular Staff) 2023 Forecasted Labour Rate

Rate Component	Billable $ per Hr.
Meal Surcharge	$8
Payroll Obligations	$79
Non-Labour Administration Costs	$8
Non-Project, Administration, Management and Support Services Labour	$81
Total	**$176**

2.1.1 PAYROLL OBLIGATIONS

A brief description of the cost elements included in this category is provided below.

Labour and Payroll Allowances (73.8% of Payroll Obligations)

- Base Pay: Contractually negotiated and reflected in union wage schedules.
- Overtime: Contractually negotiated.
- Payroll Allowances: Allowances are also contractually negotiated and stated in union collective agreements. Staff are entitled to travel, on-call allowances, footwear, and other allowances where circumstances permit. Staff are also entitled to Northern and Remote overnight and lodging allowances when working directly in communities served by local diesel generation.

Company Benefits (21.9% of Payroll Obligations)

- Regular Staff: Comprised of Pension (16.7% of base pensionable earnings) and current and post-employment benefits; health, dental, etc. (29.0% of base pensionable earnings).

Government Obligations (4.3% of Payroll Obligations)

- Consists of Canada Pension Plan, Employment Insurance, Employee Health Tax and Workplace Safety and Insurance Board Schedule 1 Premiums;
- In 2023, 5.9% is to be applied against total earnings (includes base pay, bonus, overtime, benefits and taxable allowances) to recover these costs.

2.1.2 NON-LABOUR ADMINISTRATION COSTS

This category consists primarily of non-labour expenses incurred by the business necessary for the business operations. This includes facility costs related to the main office, property taxes, utilities, telephone, insurance, maintenance, materials and supplies. It also includes items such as travel, training, advertising, postage, office supplies and low value computer equipment and services. Non-labour administration costs are budgeted based on historical trends and consider current company initiatives and individual interdepartmental needs.

2.1.3 NON-PROJECT, ADMINISTRATION AND SUPPORT SERVICES LABOUR

This category consists of labour costs incurred in non-project, administrative, management or support service roles. These costs include management and technical staff providing support services to manage and monitor the status of the assigned programs and projects. Some other functions include finance, stock-keeping, fuel management and flight logistics. Additionally, it includes time for attendance at safety meetings, housekeeping and downtime often resulting from inclement weather. This category includes employee vacation and statutory holidays, all established and identified in union collective agreements; sickness costs are also included. These estimates are based on staff count, historical trends and consider current company initiatives.

2.2 TRANSPORT & WORK EQUIPMENT (T&WE)

Remotes utilizes Networks owned fleet assets as per the conditions of the Service Level Agreement (SLA) with Networks. This SLA is for fleet management, maintenance, repair and rental services relating to the use of transport and work equipment used by Remotes. Remotes incurs the cost of transporting work equipment into remote locations, as well as flight costs associated with sending the Networks fleet mechanic to these locations. Periodically, Remotes also incurs fuel and maintenance costs outside of those incurred by Networks (and included in the SLA). Each equipment class has a standard equipment rate which is calculated by dividing the annual forecast cost by the annual forecast hours the class of equipment is required to work (utilization hours). Utilization hours are derived based on a review of historical trends and an annual review of the upcoming work program.

2023 T&WE Cost Forecast (including SLA)	$1,537k
2023 Forecasted T&WE Hours	24,510
2023 Total Average T&WE Rate/Hour	$60

2.3 MATERIAL COSTS AND SURCHARGES

Material costs charged to a project or program are based on the issue cost from Inventory, which is the Average Unit Price or the direct-shipped purchase order price. On a monthly basis, the total monthly material and contract charges are surcharged with a fixed percentage to cost effectively recover the Corporate Common Functions and Services cost allocation to Remotes for services provided by Supply Management Services (SMS). These are costs associated with purchasing, negotiating contracts and transportation management. The percentage rate is derived by assigning the costs of SMS to projects based on an annual material and contract forecast. The 2022 SMS rate is 0.8%, with forecasted 2023 rates expected to be similar.

A freight surcharge is applied to all distribution capital and external work to allocate freight costs incurred for winter road delivery of distribution inventory line materials to remote communities. The percentage rate is derived by using the forecasted freight expense and projected material expense for planned distribution capital.

2.4 SUNDRY - PASSENGER FLIGHT COSTS AND MEALS

The cost of transporting staff to remote locations is charged to the project that is benefiting from this expense. Flight service is tendered to obtain the most cost competitive contract and is split amongst a variety of providers. Efficiencies are achieved with coordinating the schedule of work and work groups to share flights.

To carry out operating, maintenance and capital work activities, it is necessary for trade and technical staff to stay overnight in remote communities at Remotes' staff houses on an ongoing basis. Food supplies are required, and the cost of these supplies is allocated to direct work programs based on labour hours charged by the two primary trade and technical labour groups and is therefore recovered in the hourly charge out rate. The rate per hour is based on forecasted meal expense and planned labour hours.

This page has been left blank intentionally.

CORPORATE STAFFING

1.0 STAFFING STRATEGY AND OVERVIEW

Remotes' workforce planning and staffing strategy is focused on building a highly skilled and knowledgeable workforce necessary to execute its strategy. In an industry faced with an aging workforce, and the challenges of a competitive labour market, Remotes must position itself to attract, motivate and retain talent, to maintain and renew its generation and distribution systems.

Remotes' work is performed by regular staff, hiring hall staff, apprentices, students, and services purchased from Networks, contracts with external firms who provide environmental services and by contracts for services with local communities, for agents and meter readers, and for casual resources related to land assessment and remediation, construction and CDM projects.

As of June 2022, Remotes has 61 full-time, regular staff. Additional resources used to supplement Remotes' regular employees include casual skilled trades staff contracted through the Hiring Hall (Power Workers' Union) and temporary staff. Remotes employs approximately ten to fifteen hiring hall staff, apprentices, and students each year. Remotes' work program has increased significantly over the past four years due to a more active role in generation upgrade construction projects. Most of the increased work program has been handled through the use of non-regular staff, seasonal or project specific trade staff.

Remotes staff complement performs the following functions: design and manage generation and distribution assets, construction planning, project management and commissioning, environmental management and support services, financial support and services, regulatory support and services, customer outreach, contact and billing/collection services, program management, work execution, planning and management/supervision, skilled electrical and mechanical trades work and fuel and material inventory management.

Due to the nature of Remotes' service territory, extensive travel and time away from home may be required. Staff recruitment and retention can therefore be challenging. Additionally, about one third of Remotes employees are eligible for an undiscounted retirement over the next five years. Remotes has several regular staff positions that are essentially "one of" positions or blended roles. If an employee leaves the company to retire or pursue other opportunities, Remotes' work program can be negatively affected until the job duties are mastered by the departing employee's replacement.

To address the training risk associated with staff retirements, Remotes creates succession plans for key employees and attempts to offer some overlap between new employees and retiring employees so that a skill and knowledge transfer can take place. Remotes also participates in Networks' established recruitment, apprenticeship and training programs, and benefits from opportunities to employ skilled staff on a temporary basis (on rotations for example). Apprentices and co-op/summer students are also used to supplement regular and hiring hall (casual) staff resources.

Contracts with First Nation Agents/Operators through Band offices provide the following functions: minor maintenance on diesel generators; initial emergency response and assessment; fuel delivery, receipting and inventory monitoring; diesel station and staff house janitorial work; line switching in the event of a house fire; and meter reading. External workers are also secured through Band offices for meter reading services, translation, and logistical assistance for community/customer meetings, to work on construction projects and on Land Assessment and Remediation projects.

Remotes also contracts with Networks for various services. These contracts give Remotes access to a greater pool of employees than would otherwise be the case for a small utility. Remotes also contracts supplemental lines and trouble response services, forestry services, purchasing services, legal services, information technology services, corporate accounting services, safety and work methods and training services from Networks under Service Level Agreements. All services between affiliates follow the Affiliate Relationships Code (ARC) for Electricity Distributors and Transmitters. These agreements allow Remotes to supplement their regular staff and to access professional and trades staff required on a less than full-time basis and in specialized fields. Additional information about affiliate service agreements is found in Exhibit A, Tab 5, Schedule 2.

2.0 STAFFING STRUCTURE

There are seven main categories of labour resources:

i. PWU-represented staff: The Power Workers Union (PWU) is an industrial union that represents the trades, technicians, and clerical workers. Within Remotes, PWU staff perform line work, electrical, mechanical, protection and control, civil, stock keeping, other technical and clerical/administrative work. These include Hydro One electrical maintainers, line maintainers, mechanical maintainers, engineering technicians and administrative employees.

ii. Society-represented staff: The Society of United Professionals (SUP) is a professional union that represents engineers, accounting, technical, administrative, and supervisory staff. They perform engineering, high level technical and administrative work as well as supervisory functions.

iii. Management staff (often referred to as 'MCP' or 'MGT/Non-Represented – MGT/N-R') are excluded from representation because they carry out managerial duties or work on confidential labour relations matters or legal matters.

iv. Temporary Employees who are employees performing work in any of the three categories set out above and who are engaged in work that is not of a continuing nature.

v. Contracted Staff are individuals engaged as independent contractors and are not on Remotes' payroll. They are engaged for varying amounts of time and paid varying amounts commensurate with their skill sets and the market rate for that skill. Contract staff are tracked and charged to Remotes by work programs or activities and not by headcount. Where applicable, the procurement of contract staff is governed by the terms of the collective agreements between the Corporation and its respective unions.

vi. Station operators and meter readers are community-based resources normally contracted through the local Band Council. Station operators are responsible for routine inspections of the diesel plants; minor maintenance such as changing oil filters; reporting station problems to the Thunder Bay service centre; monitoring fuel deliveries; emergency response; and the safe handling and disposal of waste. Remotes has a primary operator and a back-up operator for each station. Local meter readers are responsible for reading meters and for reporting meter readings to the Thunder Bay Service Centre.

vii. Casual workers are used for building projects, Land Assessment and Remediation projects and other projects. Casual workers may be acquired through the PWU hiring hall, or contracted through local Band Councils, depending on the type of work and skills available in the community.

As of June 30, 2022, the internal staff count for Remotes is as follows:

Table 1 - Staffing Count

	All Staff	% All Staff	Regular Staff	% Regular Staff
MCP/Non Represented	5	7%	5	8%
Society of United Professionals	16	22%	16	26%
Power Workers Union	40	55%	40	66%
Power Workers Union Hiring Hall	12	16%		
Total	73	100%	61	100%

The management structure at Remotes is very lean, versatile, and flexible. Although a subsidiary of Hydro One, Remotes is a small business, and like most small businesses, many managers and supervisors wear multiple hats and require a wide breath of knowledge. Ground level employees also require that same flexibility and knowledge, given some of the logistical and operational obstacles needed to overcome when working largely independently in a remotely located, isolated community.

3.0 COMPENSATION

As a subsidiary of Hydro One, Remotes is subject to the same collective agreements as Hydro One Networks. PWU and Society-represented staff comprise over 90% of Remotes' staff and are compensated in accordance with the collective agreements negotiated by Hydro One. Remotes' Management Staff are non-Executive management and are compensated through base salaries and an incentive plan that rewards performance. Detailed information on wages, salaries and overtime payments related to regular, temporary, and hiring hall employees can be found in Exhibit D, Tab 3, Schedule 1, Attachment 1. Further information about Hydro One workforce planning and employee compensation, including employee benefit programs, pensions, other post-employment retirement benefits can be found within Networks filing EB-2021-0110, Exhibit E, Tab 6, Schedule 1. A copy has been included as Attachment 2 to this Exhibit. Information regarding Hydro One's Remotes pension and other post-employment benefit costs (OPEB) including accounting can be found in Exhibit D, Tab 4, Schedule 1.

Remotes has not undertaken any relevant studies (e.g., compensation benchmarking) conducted by or for the distributor, unique to Remotes.

There are few minor compensation items that are unique to Remotes relative to Networks and other utilities. Given the small business structure of Remotes, some employees perform additional paid duties outside of normal job classification. By example, the Remotes stock keeper also fulfills the role of inventory analyst on occasion and is paid a modest premium for the extra duties. Represented employees are also entitled to negotiated overnight field allowances and subsistence allowances related to overnight stays in isolated communities. Remotes field staff also generally work increased amounts of overtime relative to other organizations. Given travel and logistics in remote locations, field tool time can often be cut short while work requires completion. In these situations, it is significantly more cost effective for Remotes to pay added overtime than to organize a return trip via charter aircraft the following week.

PERFORMANCE PAY

There are five management employees within Remotes who are eligible for an annual incentive-based payment (known as STIP) as a component of their total cash compensation.

The Short-Term Incentive Program (STIP) is designed to reward participants for the achievement of annual team (corporate) and individual performance goals. This performance pay program, introduced in 2016, is the same program that applies to all other Hydro One managerial employees (classified as MCP), such as those at Networks. STIP rewards are based on performance measured against the broader Hydro One Limited scorecard, Remotes' scorecard, and individual performance measured against annual business, departmental or personal objectives. STIP amounts are provided to eligible employees in the first quarter of the following year.

Senior level management, of which Remotes has one employee, are also eligible to participate in a Long-Term Incentive Plan (LTIP). It is an important component of executive and senior management compensation, encouraging retention of experienced senior managers who have the skills and experience necessary to execute on Remotes' goals. LTIP amounts are accrued on an annual basis and paid to eligible employees on three-year cycles. The first LTIP amounts for eligible employees in Networks and Remotes was paid out in 2018.

4.0 WORKFORCE PLANNING & VARIANCE DISCUSSIONS

Table 2 below provides a summary of Remotes' staffing expenditures for the historical, bridge and test years.

Table 2 - Number of Employees and Total Compensation Costs (*in thousands $*)

	2018 OEB-Approved	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Number of Employees (FTEs including Part-Time)							
Total	61.3	64.7	68.0	69.0	70.7	70.6	72.4
Total Compensation (Salary, Wages, & Benefits[1])							
Total	$9,481.7	$9,895.4	$10,262.7	$10,273.3	$11,176.7	$11,240.6	$11,766.6

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

Total forecasted compensation expenditure variance of $2,284k reflects growth in workforce of approximately 11 FTEs from 2018 to 2023. Secondly, increases in annual compensation costs are attributable to negotiated increases for represented staff as well as salary adjustments for non-represented employees.

Total forecasted staff count includes the increased use of Hiring Hall construction employees and the addition of a Community Relations & Customer Programs Coordinator, distribution metering and engineer technician, Regional Lines maintainer(s), Stockkeeping, P&C technician, Operations officer, Customer Care administration and Customer operations support.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

Total forecasted compensation expenditure variance of $590k reflect annual negotiated increases plus non-represented adjustments to base salary.

The PWU and SUP agreements will expire in March of 2023 and will be re-negotiated by Hydro One. The results of these negotiations will be applied to employees of the Remotes' workforce that are represented by these unions.

---

[1] Refer to Appendix 2K in Exhibit A-02-02, Attachment 1

Total forecasted staff count includes the increased use of Hiring Hall construction employees and the addition of Environmental planner, and Customer Care administration.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

Total forecasted compensation expenditure variance of $526k reflect negotiated wage increases plus adjustments to non-represented base salaries, and minor increase to overall FTE levels.

The PWU and SUP agreements will expire in March of 2023 and will be re-negotiated by Hydro One. The results of these negotiations will be applied to employees of the Remotes' workforce that are represented by these unions.

Total forecasted staff count includes the increased use of Hiring Hall construction employees and the addition of Customer Care administration.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

Total forecasted compensation expenditure variance of $64k reflect negotiated wage increases plus adjustments to non-represented base salaries.

Total forecasted staff count includes the increased use of Hiring Hall construction employees and the addition of a P&C technician.

2018 ACTUALS VS 2018 OEB-APPROVED

Total compensation expenditure of $413k reflect increased staff count and increased performance pay due to plan design (see page 6, above).

2018 OEB-approved figures were based on target performance scores, whereas 2018 Actuals reflect total amounts paid based on actual performance scores. In 2017, Hydro One Limited performance scores significantly exceeded target. Performance payouts issued in 2018 were higher than forecasted. As Remotes MCP employees are subject to the same STIP as Networks employees, the 2018 performance pay reflects the above-target performance outcomes from 2017. 2018 Actuals also include an LTIP payment which began accruing in 2016.

Total staff count includes the increased use of Hiring Hall construction employees and the addition of new Community Relations & Customer Programs Coordinator as per the settlement conference.

5.0 WORKFORCE PLANNING IMPACTS 2023-2027

Over the next five years, Remotes is expecting that the staff count will grow approximately 10-15% (7-10 FTEs) as the business transitions to a hybrid business model offering both off-grid and on-grid services and serving additional communities. The increase in staff is largely related to the Watay grid which drives new business requirements and processes. Most of the increase is expected on the distribution service side including the addition of lines journeyperson(s), distribution metering and engineer technicians, customer operations or care administration staff. Increased P&C resources necessary to support both revenue metering, back-up power, IT and communications infrastructure are expected. The Generation group will remain relatively flat, depending on Remotes' involvement necessary to support and provide back-up power. An additional MCP manager is also under consideration depending on the need to better align the organization with the future requirements. Contracted work with both external suppliers and First Nation partners is expected to increase as more communities are served. In the 2026-2027 period, Remotes is anticipating a slow-down in generation-related construction and upgrade projects, which will result in a slight reduction of seasonal Hiring Hall construction staff.

Work programs for both distribution and generation are largely contingent on federal First Nation infrastructure funding programs related to education, health, water, and housing. The current federal government has committed strongly to improving the quality of life experienced by indigenous Canadians. Customer programs and initiatives will continue to take priority and will impact Remotes' overall staffing needs.

All new expected positions are identified based on need and require written justification and approval during the business planning process. New positions added to Remotes would likely be subject to existing collective agreements. Any new positions will be staffed on a full-time basis only if the work plan indicates the need for labour will be persistent and on-going for multiple years.

Please refer to Exhibit A, Tab 7, Schedule 2 for forecasted inflation rates and expected labour escalation.

COMPARISON OF WAGES

This exhibit has been filed separately in MS Excel format.

CORPORATE STAFFING AND COMPENSATION

1.0 INTRODUCTION AND OVERVIEW

This exhibit describes the aspects of the workforce that build, operate, and support Hydro One's Transmission and Distribution systems; and details the compensation paid to this workforce, as well as the steps taken by Hydro One to prudently and efficiently manage its size and overall cost. To optimize workforce size and composition (i.e. workforce mix), Hydro One will leverage the workforce flexibility achieved in previous rounds of collective bargaining to manage the increase in planned work without significantly increasing the size of its regular workforce. In terms of relative compensation levels, Hydro One has made significant progress in addressing its position relative to market (compared to prior years). Furthermore, Hydro One will continue to pursue market competitiveness through its labour relations strategy, and anticipates moving even closer to market by the end of the rate period.

Part One of this exhibit describes the composition and size of the workforce that Hydro One requires over the 2023-27 rate period to execute its Investment Plan and to operate the Transmission and Distribution systems. As described in this part, Hydro One has undertaken a rigorous workforce planning process to determine the appropriate level and types of resources to deliver its planned work.

Part Two of this exhibit describes the compensation paid to Hydro One's workforce, both unionized (represented) and non-represented, and details the forms of compensation the workforce receives. Given the preponderance of unionized employees, Part Two of this exhibit also discusses the labour relations context that influences the workforce. Additionally, Part Two also addresses the relative competitiveness of Hydro One's levels of compensation, as reflected in the updated 2020 results of the benchmarking study conducted by Mercer Canada (the Mercer Report). As directed by the OEB in EB-2019-0082, this part includes Hydro One's plan to further align its compensation levels with market.

2.0 PART ONE – DESCRIPTION OF HYDRO ONE'S WORKFORCE & RESOURCE PLANNING PROCESS

This section describes the size and composition of Hydro One's workforce and how that workforce is used to deliver Hydro One's planned work. Overall compensation costs are impacted by the size of the workforce, the types of resources engaged (the level and type of FTE[1], known as the workforce mix), as well as the level and form of compensation paid to the workforce. Hydro One's rigorous workforce planning is therefore an essential component of ensuring cost-effective and efficient work delivery.

To execute the planned work, each line of business within Hydro One determines the amount of employees (the level of FTEs[2]) required. Resourcing plans vary across functions (Distribution, Transmission, and Corporate) and between the Transmission and Distribution Lines of Business (LOBs). These plans encompass the increases or decreases required to the workforce, as well as determining whether external resources (contracting out) will be needed and can be used to support increasing levels of work.

Hydro One's workforce is comprised of three types of employees according to their status: (i) regular, (ii) casual, and (iii) temporary. Regular employees make up 67% of the total workforce. Casual employees are approximately 31% of the total workforce, and temporary employees are about 2% of the total workforce as shown in Figure 1.

As shown in Figure 2, approximately 92% of Hydro One's total workforce (regular, casual and temporary) is represented by a union and subject to the terms of a collective agreement.

---

[1] Full Time Equivalent (FTE)

[2] At Hydro One, FTEs represent average monthly headcount over a 12 month period. A regular status employee who is budgeted for one year of work, represents one FTE. For casual employees, one FTE equates to 12 person months of work. As causal employees may not work a full twelve months, the resources required are evaluated by FTE levels, not by actual casual headcount.

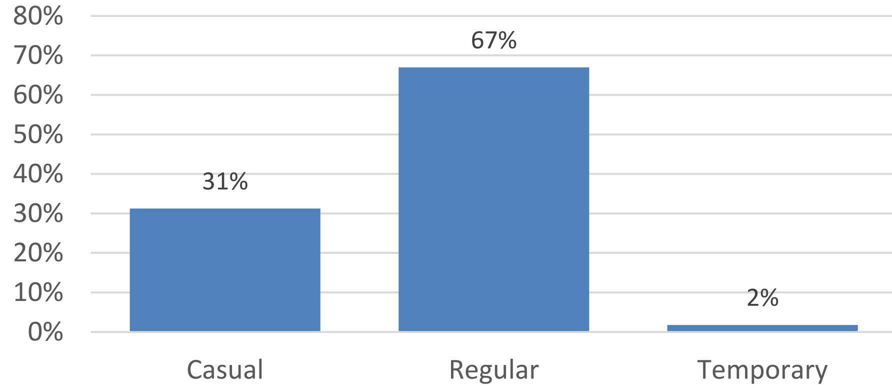


Figure 1: Total Workforce Segments 2020

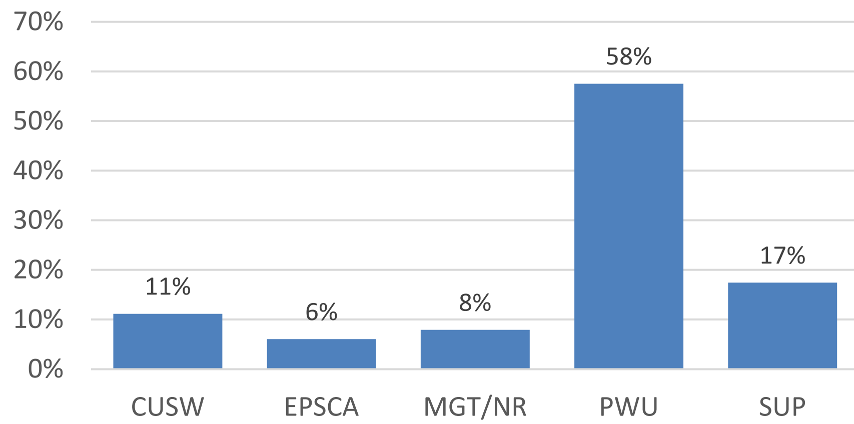


Figure 2: Total Workforce Representation[3] Groups 2020

[3] CUSW is the Canadian Union of Skilled Workers; EPSCA refers to those employees represented by a casual trades union that negotiates with the Electrical Power Systems Construction Association; MGT/NR refers to management/non-represented, which captures employees in managerial roles, and those who are not represented by a union; PWU refers to the Power Workers' Union; SUP is the Society of United Professionals.

2.1 REGULAR EMPLOYEES

2.1.1 REPRESENTED GROUPS

Approximately 88% of regular employees (and 92% of all employees) are represented by unions. About 63% of regular employees (and 58% of all employees) are represented by the Power Workers' Union (PWU). Approximately 25% of regular employees (and 17% of all employees) are represented by the Society of United Professionals (SUP). In respect of both PWU and SUP represented employees, Hydro One competes to attract, retain, develop and motivate these highly skilled workers in order to execute Hydro One's growing work program. These employees are sought after by other employers, including the Ontario Hydro successor organizations and other utilities.

Employees represented by the PWU perform technical, trades, or clerical work under the main PWU agreement, or customer service and call centre work under the CSO agreement. These employees perform lines, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operations and clerical/administrative work. A significant portion of this workforce is trained internally through the apprenticeship program described below and other trainee programs.

Approximately 40% of regular, full time PWU-represented employees (15% of the entire Hydro One workforce) work as Regional Maintainers (RMs), a role unique to Hydro One. RMs are qualified members of a skilled trade in the areas of Lines, Electrical, Forestry, Civil, or Mechanical work. In addition to obtaining a trades certification, RMs are also expected to be capable of lead hand type duties, contract monitoring, and protection and control duties, in addition to their trade-related responsibilities. On average, it takes four to five years to become minimally qualified in a skilled trade specific to the utility sector through a combination of an apprenticeship/trainee programs and on-the job training. Becoming a fully qualified RM takes another one to three years.

Employees represented by the SUP occupy roles related to technical, engineering, supervisory and/or financial and analytical work. An example of a supervisory role includes the First Line Managers (FLMs) who oversee the work of PWU staff in areas such as Lines, Forestry, and other technical services. SUP-represented staff also play key role in the oversight, analysis, and business planning of network operations, as well as protection and control work and project management.

The collective agreements between Hydro One and the PWU and SUP originate with Ontario Hydro, the predecessor company that was split into five entities in 1999 (referred to hereafter as the OH demerger). The terms of the PWU and SUP agreements are comprehensive and complex. Changes to the terms of these agreements are negotiated through the collective bargaining process. Among the terms of these agreements are:

- conditions of employment: wages, leave (vacation and sick leave etc.), pension and benefits;
- selection language: provisions relating to candidate qualifications for vacancies/job competitions;
- employment security language and severance entitlements: processes for layoffs, seniority, displacement of workers in event of layoffs;
- provisions pertaining to scheduling, hours of work, overtime rates; and
- a description of work jurisdiction and contracting-out provisions.

2.1.2 MANAGEMENT AND NON-REPRESENTED (MGT/N-R) EMPLOYEES

The remaining 12% of the regular workforce (8% of the total workforce) are not represented by a union. These are primarily employees in managerial roles, as well as those positions that are excluded from union representation for reasons such as confidentiality related to labour relations or legal matters.

The managerial workforce leads the company by setting strategy and providing work direction. Hydro seeks to hire a mix of internal and external talent for these roles. In order to attract and maintain an appropriate managerial workforce, Hydro One must provide a market competitive compensation package. Attracting talent from represented roles into management can be challenging for reasons related to compensation and job security. Accordingly, the compensation and benefits package for management employees includes: (i) a market-based and segmented base pay structure; (ii) incentive-based pay or pay at risk; (iii) a defined contribution pension plan;[4] (iv) an optional employee share ownership plan with employer enhancements; and (v) health and dental plan, with paid vacation, short-term sick leave, and long-term disability benefits coverage.

2.2 CASUAL EMPLOYEES

Casual employees are typically retained for 40 hours a week for a fixed period of time to execute and support construction work, supplemental maintenance work, supplemental customer service and clerical support work, or are completing an apprenticeship program.

As presented in Figure 3, casual workers are either:

- Represented by the PWU and employed through a hiring hall as discussed further under Section 2.2.1 below;
- Represented by the Canadian Union of Skilled Workers (CUSW) who perform skills trades work in transmission system construction; or
- Members of a building trades unions, such as the Carpenters, Labourers (LIUNA), Operating Engineers, or Ironworkers, which negotiate agreements with a group of employers known as the Electrical Power System Construction Association (EPSCA).

[4] All management/non-represented employees hired since 2015 participate in the currently offered defined contribution pension plan; those hired prior to 2015 are members of the previously offered defined benefit pension plan.

Figure 3: Representation of Casual Workforce

Unlike Regular employees, casual employees are contingent workers hired to perform specific work for a set period of time and then are laid off. For casual trades employees represented by CUSW or one of the construction trade unions that negotiates with EPSCA, conditions closely align with the construction industry, which is subject to specific conditions and exceptions within the larger labour relations and employment law regimes of Ontario. The PWU hiring hall which is discussed under Section 2.2.1 (for both the main agreement, and the Customer Service Organization), CUSW, and other casual construction trades employees, receive a total wage package (including amounts for benefits and pension payments) for each hour worked, and are not entitled to notice and severance when work ceases, (i.e. when they are stand down or are laid off), and do not have access to paid sick leave under the terms of their collective agreements.

The flexible terms of casual labour ensure that workers with the required skill set are hired in the right location for only the duration of the work assignment, and that Hydro One has no ongoing obligations with respect to benefits or pension.

Witness: LILA Sabrin

2.2.1 PWU HIRING HALL

The PWU administers a hiring hall (HH) of contingent workers to meet fluctuating work demands (e.g., incremental work, the Apprenticeship Program, and special projects), performing primarily supplemental construction, maintenance, customer service and administrative/technical work. As noted above, similar to casual construction employees, PWU hiring hall workers do not join pension or benefit programs, are not entitled to paid vacation/statutory holidays/sick days off (rather, are paid a % in lieu of statutory holidays and vacation), and can be deployed in a more flexible manner. When workers are required, Hydro One will requisition this labour through a union-run hiring hall directly, and it is up to the union to ensure the labour demands can be met, and the staff within their hall are qualified and ready for work.

2.2.2 PWU APPRENTICESHIP PROGRAM

In addition to using PWU HH labour for temporary and supplemental maintenance work, Hydro One's entire apprenticeship program is subject to the terms and conditions of the PWU HH. Apprentices are employed as casual workers throughout their program, receiving a base salary, and set hourly cash amounts for pension and benefits. The PWU administers the pension and benefits program for these workers as they do for other workers from the HH. There is no guarantee of ongoing work for an apprentice while they are acquiring the necessary training and experience within the lines or electrical trades. Apprentices must apply to a regular position once the program has been completed (after approximately 4 to 5 years). Thus, unlike other utilities, apprentices do not join the pension plan until they have been selected for a regular position. Furthermore, lines trade apprentices are deployed to support both Transmission and Distribution work, making them a flexible and adaptable resource to meet work demands, and support a variety of work programs.

2.2.3 CANADIAN UNION OF SKILLED WORKERS (CUSW)

Hydro One relies on CUSW-represented employees to perform construction industry work on the electrical power systems. Specifically, these employees are lines and electrical tradespersons who perform work primarily on the construction of lines over 50 kV, transmission stations, switchyards, substations, system control centres, and associated telecommunications systems. This group makes up one-third of all casual employees at Hydro One.

2.2.4 CONSTRUCTION TRADES EMPLOYEES

These are casual status employees that are represented by construction (or building trades) unions (such as the Labourers, Operating Engineers, or Carpenters) that supply a contingent workforce through their hiring halls, and negotiate their collective agreements with EPSCA. EPSCA is made up of employers performing construction industry work for the Bulk Electric System on property owned by Ontario Power Generation Inc., Bruce Power LP and Hydro One. This association negotiates and administers collective agreements with the construction trades unions for employers performing work in the Electrical Power System Sector under the *Ontario Labour Relations Act*. There are 17 construction trade unions that negotiate with EPSCA.

2.3 TEMPORARY EMPLOYEES

Temporary employees exist in each of the three groups discussed above (PWU, SUP and non-represented). These employees are typically retained for 12 to 15 months, or up to 2 years for some non-represented positions. Temporary employees are hired to fill positions where the duration/extent of the work does not warrant retention of a permanent employee.

2.4 USE OF EXTERNAL RESOURCES

In addition to the internal workforce described above, Hydro One also uses external resources (such as third-party contractors) to support work execution. The extent to which work can be performed by external resources depends on the type of work to be performed. Also, the existing work jurisdiction of the PWU, and the SUP, may impact the scale and/or type of work that can be performed externally.

2.4.1 CONTRACTING OUT

Hydro One will continue its use of strategic contracting, scaling up as required to meet growing work demand in 2023 and beyond. Contracting out allows Hydro One to efficiently manage higher demand, thereby reducing the need to add additional regular FTEs with their associated long-term costs for pension and benefits. Hydro One maintains its regular staffing levels to correspond generally to its fixed level of work, rather than maintaining a larger complement of internal resources to respond to temporary increases in work demand, incremental/seasonal work, and short-term work. Such resourcing options are primarily contingent on the type of work to be performed.

The PWU Collective agreement contains provisions that address contracting out (referred to as Purchased Services Agreements or PSAs). Some types of work that Hydro One seeks to contract out may require negotiation with the union partners or an award from a labour arbitrator. Factors such as labour availability within existing casual hiring halls may be relevant to the determination of the types and volumes of work that can be contracted out.

Some categories of work have been subject to long-standing PSA arrangements, which have been integrated into the PWU collective agreement. For example, the agreement known as Mid-Term 50, permits the contracting out of entire categories of work, such as: snow removal, janitorial, heavy and/or specialised equipment operation (hydrovac, backhoe), and minor fleet maintenance, thereby allowing Hydro One to contract out work to organizations that specialize in these areas. These arrangements provide flexibility, as they enable on-demand resources to be deployed as required through various contracting partners, and allow Hydro One to avoid the costs of equipment, maintenance, labour, and training for services that are needed on an intermittent basis, or are highly specialized.

For the Transmission organization, there is a long standing practice of contracting out, which is also recognized in the CUSW collective agreement, such as in the provisions which stipulate those employees represented by the International Brotherhood of Electrical Workers (IBEW) can perform electrical construction work through affiliated contractors. In Ontario, there are two electrical unions which represent electrical construction workers in this sector - the IBEW and the CUSW. The language in the CUSW collective agreement allows for work to be contracted out to either (a) CUSW-affiliated contractors, (b) IBEW-affiliated contractors, or c) other contractors agreeing to apply the terms and conditions of the CUSW agreement.

2.4.2 INDIVIDUAL CONTRACTORS

A small portion of work at Hydro One is performed by individuals that are engaged as contractors. These individual contractors differ from the contracted firms retained to scale up operations, or support incremental/specialized work (typically vendors or general contractors that supply specialized services for seasonal/incremental work, or support capital work programs, specific engineering work, or provide other specialized construction services). Hydro One retains individual contractors to perform professional services, primarily in IT operations, as well as for project management functions.

These contractors are retained for their particular skill sets on projects, and/or to perform other work that is not of an ongoing nature. They are engaged for varying amounts of time and paid fees commensurate with their skill sets and the market rate for their skills. The costs associated with retaining contract staff are tracked by work program and not by headcount. Where applicable, the use of contract staff is governed by the terms of the collective agreements between Hydro One and its unions.

2.5 PLANNING PROCESS & ANTICIPATED FTE LEVELS FOR THE RATE PERIOD

As noted, Hydro One's overall workforce compensation costs are determined by the size and composition (mix) of the workforce, as well as the level of compensation paid to the workforce.

In order to ensure costs are managed prudently and efficiently, Hydro One carefully plans its resourcing requirements to determine what types of internal resources (FTEs) and external resources (contractors) are required to execute its work-plan in a cost-effective manner. As shown in Figure 4, the planning framework considers Hydro One and LOBs operational needs, the Investment Plan requirements as well as OEB direction, to develop a consolidated business plan which includes FTE planning assumptions.

Figure 4: Planning Framework

Based on asset condition, growth, and customer feedback, Hydro One has adopted an Investment Plan which will entail increased levels of capital work. To determine the size of workforce and external resources required to execute the Investment Plan, Hydro One engaged in a multi-stage resource planning process to evaluate its existing staffing levels, assess resourcing options available, and develop the preferred resourcing and execution options appropriate for each LOB.

As discussed below in Part 2, Hydro One has continued to make progress in reducing the level of compensation paid (relative to market median) by negotiating modifications to its collective agreements. However, Hydro One's overall compensation costs are also managed through careful resource planning, and the optimization of existing internal resources. This requires proactive planning for the level and types of FTEs required to deliver the growing volumes of work during the 2023 to 2027 rate period. It also requires leveraging existing workforce flexibility: the efficient assignment of work to existing staff; the increased use of casual labour; and contracting out work where appropriate and consistent with existing collective agreements.

2.5.1 HYDRO ONE'S COMPREHENSIVE APPROACH TO WORKFORCE PLANNING

Hydro One's resource planning process is based on two core tenets:

a) decisions are to be driven by customer-focused outcomes, safety, efficiency and cost-effectiveness; and,

b) the size of Hydro One's regular workforce should correspond to on-going work requirements and incremental work should be staffed efficiently using a mix of regular, casual, temporary and external resources as required.

As noted above, resourcing decisions are impacted by the type of work to be performed. The appropriate resourcing options for each LOB depend on a variety of factors which must be considered, including:

- **Cost** - Identify the mix of resources that will allow Hydro One to deliver its work plan safely, efficiently and in compliance with collective agreements, while minimizing lifecycle cost.
- **Workforce Balance** - As some types of work will be performed by the same workforce regardless of Hydro One's resourcing decisions (i.e. construction work will be performed by the same unions regardless of the employer), the cost of labour is not the sole factor considered in determining the appropriate resourcing option. Incremental increases in specific types of work must be staffed in a manner that does not redirect resources from other work priorities, and time-sensitive work.
- **Duration and scope of work** - The length of the work, and preferred timeline for completion, will impact resourcing decisions. If the work is temporary in nature, external delivery is often appropriate.
- **Complexity/specialization** - Highly specialized, or complex work that is not foundational to electrical grid operations, or is required only intermittently, may be more appropriately contracted out to minimize the cost of training and recruitment. In certain areas (e.g., building design), using external resources also allows Hydro One to access highly specialized expertise and industry leading firms. However, the need to maintain internal expertise may require performing some types of specialized or intermittent work in-house with the resources that perform this work being redeployed to other tasks when not needed for their specialization.
- **Specialized equipment** - Certain work requires investment in specialized vehicles and equipment with associated capital, training, maintenance, and other costs. These costs

may warrant using external firms with greater specialization and higher utilization factors.

- **Technical, security, and risk-related considerations** - Corporate functions that necessitate internal oversight (such as cybersecurity for critical infrastructure), may warrant adding regular FTEs to an existing LOB in the interests of risk mitigation and incident prevention. Oversight and control of processes to maintain service standards also may require retaining certain work internally.

2.5.2 2023-27 WORKFORCE PLANNING PROCESS

To formulate the FTE levels required for 2023-27, each LOB identified the key drivers of its resourcing strategy as well as current staffing levels, and determined the FTEs (regular, casual and temporary) required to support all planned work. The LOBs reviewed their resourcing plans with the support of Human Resources Department (HR) to assess feasibility and labour relations impact. Workforce planning has been fully integrated into the investment and business planning processes to ensure a thorough assessment of the necessary resource levels, and to incorporate resourcing strategies that optimize efficiency.

Hydro One's planning must also ensure that it is still able to attract, retain, and motivate the workforce resources necessary to complete work, including in light of retirement eligibility levels and the time required to complete the training necessary for skilled positions. As noted in Figure 5 below, approximately 12% to 17% of Hydro One's workforce is, or will become, retirement eligible over the rate period. These highly-skilled and experienced workers will need to be replaced in a timely fashion. Projected turnover has been accounted for in the FTE forecasts detailed in Table 1 as further discussed below under Section 2.6.

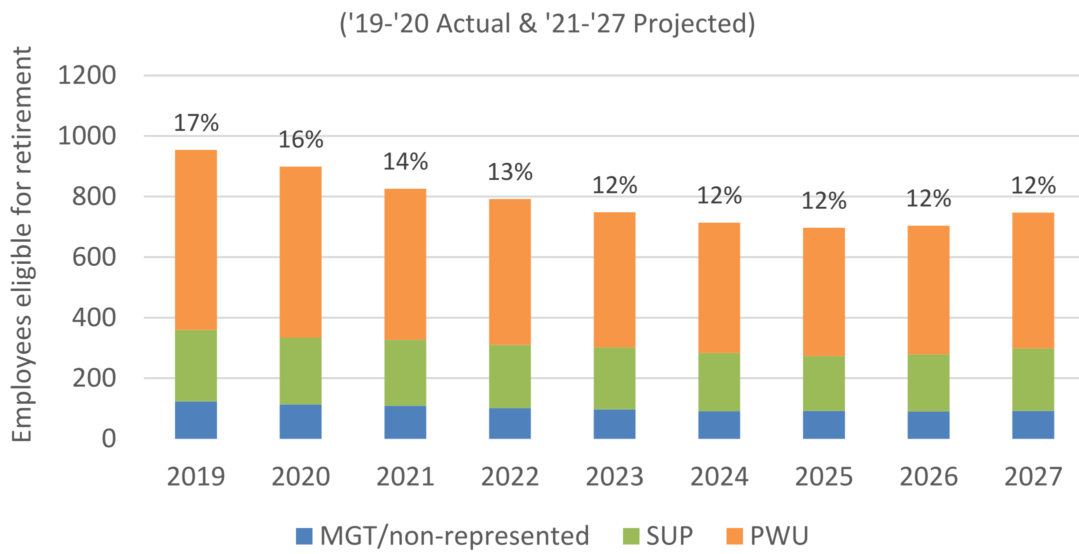


Figure 5: Retirement Eligibility[5]

2.5.3 OPTIMIZING WORK DELIVERY CAPACITY

Hydro One has the ability to accommodate Investment Plan growth without a proportional increase in FTEs because it has the flexibility to assign incremental increases in work (which is typically project-based, temporary, seasonal and/or intermittent) in an efficient and productive manner. In addition to its integrated workforce which allows resources to be deployed across both the Distribution and Transmission businesses, Hydro One also has the ability to increase the use of casuals/temporary labour as required, and to contract out work when appropriate.

Hydro One's integrated workforce creates economies of scale and efficiencies that would not be available through separate Transmission and Distribution operations, such as an integrated Lines Apprenticeship Program, asset management strategy, centralized grid control, and centralized fleet operations and common corporate functions and services. This integrated approach

---

[5] Based on pension plan membership data as of time of filing. Eligibility is defined as ability to retire with an undiscounted pension.

Witness: LILA Sabrin

enables deployment of resources across various projects and programs (e.g., Vegetation Management, New Connections, Pole Replacement, etc.)

For the Transmission and Distribution organizations, enhanced reliance on casual workers and external resources (contracting out) will support the incremental increases in work related to the Investment Plan (subject to availability of qualified contractors). The resources used to deliver the capital and Operations and Maintenance (O&M) work programs for both Transmission and Distribution are described in the Transmission and Distribution work execution exhibits (TSP Section 2.10 and Exhibit E-02-05, and DSP Section 3.10 and Exhibit E-03-05) and for the General Plant lines of business, resourcing plans are discussed further in GSP Section 4.10, Exhibit E-04-05 and Exhibit C-09-04.

Hydro One will also rely on strategic use of overtime (OT) to efficiently control resourcing levels and manage cost. OT work (work performed in addition to or outside of standard work hours within collective agreements) is an important component of Hydro One's resourcing plans - it is necessary to meet work execution requirements, customer needs and preferences, and to plan work efficiently.

The operational realities of Hydro One require two forms of OT: planned OT and demand OT. Planned OT is required to meet execution timelines, enhance the efficiency of work execution such as by minimizing travel time and to accommodate the needs of customers by managing outages during evenings and weekends to limit business disruption. This type of OT is used predominantly in the Transmission business. Demand OT occurs due to the need to execute work that has limited predictability, such as trouble calls, storm damage, and new connections. Demand OT is used primarily in the Distribution business.

All OT must be approved in advance, and is managed and monitored on a regular basis. Planning assumptions are determined by each organization, and based on internal review of previous trends (for demand OT), and work requirements, outages, and customer and/or project requirements for planned OT.

Anticipated OT usage is captured in workforce plans as a percentage of all hours forecast to be worked. Usage rates are based on historical trends specific to the type of work to be performed, and vary across job types and LOBs. The cost per hour of overtime will vary depending on the type of employee performing the work, as well as when the overtime is performed. Cost projections of overtime are calculated based on historical actuals, as explained below. The Mercer Report (Attachment 1 to this exhibit, Section 5 of the report) also addresses Hydro One's OT policies and rates, and confirms that they align with market.

Overall and in summary, Hydro One has a robust planning process that focuses on work plan requirements in order to determine necessary resourcing. Through this process, a prudent mix of internal resources has been determined on the basis of the criteria outlined above. This process ensures Hydro One has a cost efficient and right-sized workforce (with a balance of regular and casual resources), that is supplemented, as required and appropriate, by external resources (contractors) in order to complete the 2023-27 work program.

2.6 ACTUAL AND PLANNED FTEs

The results of Hydro One's planning process are captured in Table 1, which shows Hydro One's actual and planned FTEs for both Transmission and Distribution, reflecting staffing levels appropriate for the type and volume of work to be performed and contracting out portions of incremental work. A significant portion of the growth shown in Table 1 during the 2023-2027 rate period is attributable to increases in the PWU HH to manage work that is not of an on-going nature. Where necessary, Hydro One plans to add a small number of regular and casual FTEs to the existing workforce. Between 2023 and 2027, the total number of FTEs is projected to increase by only 1.4% notwithstanding the significant increase in planned work. During this period, Hydro One has prioritized maximizing output from its existing workforce, and enabling the execution of greater amounts of work with existing staff across all lines of business.

Table 1 - Actual and Planned FTEs for 2019 to 2027

Type	Representation	2019 Actual	2020 Actual	2021 Plan	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan	2027 Plan
Regular	MGT/Non-Represented	613	647	724	760	765	760	760	763	763
	Society	1425	1449	1674	1771	1781	1783	1791	1817	1841
	PWU	3534	3603	3704	3748	3737	3720	3718	3703	3674
	Total Regular	**5572**	**5699**	**6103**	**6280**	**6283**	**6264**	**6269**	**6283**	**6278**
Casual	PWU Hiring Hall	1373	1197	1329	1300	1388	1397	1480	1602	1524
	CUSW	936	948	938	911	912	912	912	912	912
	EPSCA	217	223	198	192	192	192	192	192	192
	LIUNA	272	291	247	237	237	237	237	237	237
	Total Casual	**2798**	**2659**	**2712**	**2639**	**2729**	**2738**	**2820**	**2943**	**2864**
	Temporary	194	152	175	158	159	158	157	157	157
Total		**8564**	**8509**	**8990**	**9077**	**9171**	**9160**	**9247**	**9383**	**9299**

As noted in previous applications, Hydro One's workforce plans rely on a variety of labour resources, including temporary, regular, as well as PWU and construction trade casual labour, to address the fluctuating nature of its work. As such, should work plans change, hiring plans are revised to reflect business needs. Given this reality, the 2019 & 2020 FTE levels reflect variances from previously filed workforce plans as a result of cuts following the Distribution Decision (EB-2017-0049) and the Transmission Decision (EB-2019-0082). These cuts resulted in a fewer casual FTEs retained than previously projected given the reduced levels capital and OM&A envelopes. The planned increases to regular FTEs for 2021 and 2022 noted above are attributable to the addition of approximately 250 employees into the Shared Services & Information Services LOBs due to repatriation of Inergi employees. Further details of this workforce change are discussed in Exhibits E-05-01, E-04-04, and E-04-02.

In addition, the COVID-19 pandemic resulted in delayed hiring for certain roles which accounts for the reduced number of FTEs reported in 2020.

Witness: LILA Sabrin

2.7 COST PROJECTIONS OF PLANNING ASSUMPTIONS

The anticipated costs associated with the FTE levels set out in Table 1 above are detailed in the Compensation Cost Table and explanatory notes appended to this exhibit (Attachments 2A and 2B). The Compensation Cost Table, also provided in previous rate applications, includes actual compensation costs for 2018 to 2020, and forecast costs for 2021 to 2027.[6]

Over the past several applications, Hydro One has improved the compensation cost information that is provided. The most recent Transmission and Distribution applications (EB-2019-0082 and EB-2017-0049, respectively) have included year-end FTEs, total headcount, and average month end FTEs, and the compensation costs have been broken down across Transmission and Distribution, and allocated between OM&A and capital as per the Black & Veatch methodology. In those applications, however, only FTE counts were broken down for Transmission and Distribution; FTEs were not allocated between OM&A and capital. In this current application, FTEs (average month end) are used consistently throughout, and both compensation costs and FTEs are allocated across OM&A and capital. Moreover, the allocation relies primarily on the direct assignment of costs rather than using an allocation methodology as in past applications.

3.0 PART TWO – COMPENSATION ELEMENTS & CURRENT MARKET POSITION

Part Two discusses the level of compensation and benefits paid to Hydro One employees. More specifically, this section describes the recent compensation benchmarking results, which are contained in the Mercer Report. Additionally, this section details the compensation and benefits for PWU, SUP, non-represented and executive employees. Furthermore, this part of the exhibit reviews the actions Hydro One has taken, and continues to take going forward, to control

[6] Actuals for 2018 are the same as reported in the EB-2019-0082 application, but do not include the same breakdown of temporary overtime and burden dollars as are shown for years 2019 to 2027. These categories were not included as separate lines in the compensation table filed in EB-2019-0082, therefore they are not shown in the current table. Furthermore, these amounts were subject to the previous allocation methodology used in the EB- 2019-0082 application.

compensation costs for represented employees and the context in which these efforts are undertaken.

3.1 HYDRO ONE'S LEVEL OF COMPENSATION RELATIVE TO MARKET

Mercer has undertaken an updated compensation benchmarking study, in accordance with the OEB's direction. The purpose of this study is to determine the relative competitiveness of Hydro One's levels of pay. The Mercer Report, appended to this exhibit (Attachment 1), details this study and the results of it.

As set out in the Mercer Report, the updated study shows that Hydro One's overall market position relative to the P50 market median, as of 2020, has improved. It is now 9% above this median.[7] The Mercer Report also confirms that market position for total compensation is typically within 5% of the P50 market median. Thus, an overall level of compensation that is +/- 5% of the P50 is considered to be at market. On this basis, as of 2020, Hydro One's compensation levels are now only 4% above market. These results are shown in Figure 6 below.

			Total Remuneration (Current)					
			Variance to P50					
	Hydro One Group	# of Hydro One Inc. (2020)	2008	2011	2013	2016	2017	2020
Weighted Average	Non-Represented	155	-1%	-17%	-1%	2%	1%	-4%
	Energy Professionals	400	5%	5%	9%	11%	12%	11%
	Trades and Technical	2,801	21%	18%	12%	16%	12%	10%
	Overall	*3,356*	*17%*	*13%*	*10%*	*14%*	*12%*	9%

Hydro One P50 Relative to Market P50

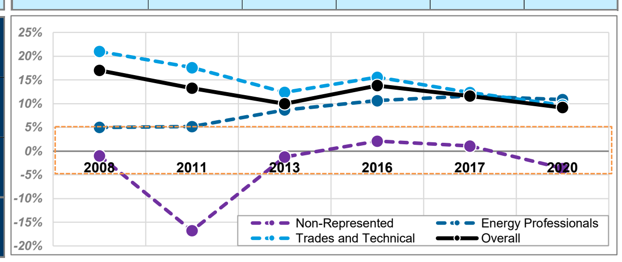


Figure 6: 2020 Benchmarking Results

[7] The overall result of 9% above the P50 market median is comprised of the following breakdown in respect of individual employees groups: Hydro One is 4% below P50 market-median for management and non-represented group; 10% above it for trades and technical group; and 11% above it for the 'energy professionals' group.

Witness: LILA Sabrin

By comparison, the previous Mercer benchmarking study conducted in 2017 (and filed in Hydro One's most recent Transmission application, EB 2019-0082 -- the 2017 Study) indicated that Hydro One's overall level of compensation was 12% above the P50 market-median. The 2020 results therefore show a significant improvement study over study in this regard -- from 12% down to 9% in relation to P50; and from 7% down to 4% in relation to the market competitive range. Further, Hydro One has made even greater progress over the past 12 years, from the first study in 2008 in which Hydro One's level of compensation was 17% above the P50 market-median to the current position of 9% above market-median. This significant improvement is the result of a focused effort to achieve market aligned compensation for represented employees, having regard to (and working within) constraints of the collective agreements and the collective bargaining context in which Hydro One operates.

The above improvement in market positioning, confirmed in the Mercer Report, indicates Hydro One's represented compensation is better aligned with market due in part to negotiated changes to the pension plan. Furthermore, introduction of lump sum and equity compensation has reduced longer-term costs associated with pensions.

3.2 TYPE AND LEVELS OF COMPENSATION PAID TO REPRESENTED GROUPS

As is typical in unionized environments, compensation and terms of employment are determined by collective agreements. At Hydro One, regular unionized employees receive a salary that is based on an hourly or weekly rate (35 or 40 hour work week), and are provided vacation, sick leave, long-term disability benefits, health and dental benefits, and other forms of paid leave. The base salary of a represented employee is typically determined by their classification and seniority. Any changes to the wage structure within these agreements is determined through the collective bargaining process.

3.2.1 PWU AGREEMENTS

The current PWU agreements are in effect until 2022 & 2023.[8] These two agreements were renewed in 2020 (ratified in late 2020) and contain annual base wages increases ranging from 1.9% to 2.2% from 2020 to 2022 (main agreement) and from 0.6%[9] to 2.2% from 2020 to 2022 (CSO agreement).

3.2.2 SUP AGREEMENT

The latest SUP agreement (for a two-year term) expired on March 31, 2021. Negotiations commenced in early 2021, and a tentative agreement was reached in June, but has not yet been ratified. The previous agreement included 2% wage increases effective on April 1, 2019 and April 1, 2020.

3.2.3 SHARE GRANTS & EMPLOYEE SHARE OWNERSHIP PROGRAM (ESOP)

PWU and SUP-represented regular, full-time employees who were members of the pension plan as of April 1st (PWU) and September 1st (SUP) 2015, are eligible to receive share grants of Hydro One Limited stock. These grants were negotiated in the 2015/2016 bargaining rounds. Eligibility for share grants continues until 2028 for PWU, and 2029 for SUP employees who maintain active employment and continue contributing to the pension plan (share grants are not issued to retired employees collecting pension benefits). As of April 2021, approximately 2,300 PWU-represented employees and 1,100 SUP-represented employees were receiving share grants. As employees retire, the number of share grants provided is anticipated to decline, as shown in Table 2 and Table 3, below.

---

[8] PWU main agreement term is April 1, 2020 to March 31, 2023, the CSO agreement is in effect from October 1, 2019 to September 30, 2022

[9] There was a 0.6% increase applied in January of 2020 from the previous renewal agreement, and then a 1.9% increase that subsequently applied in that year.

Table 2 - Share Grants Issued to PWU

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Number of Shares	371,610	353,134	341,308	327,320	311,921	302,600	294,777	289,008	278,720	267,007	262,453	259,246
Change from 2017	--	-5%	-8%	-12%	-16%	-19%	-21%	-22%	-25%	-28%	-29%	-30%

Table 3 - Share Grants Issued to SUP

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Number of Shares	128,327	121,633	114,242	108,506	105,612	102,791	100,743	98,388	95,348	93,699	92,754	91,232
Change from 2017		-5%	-11%	-15%	-18%	-20%	-21%	-23%	-26%	-27%	-28%	-29%

SUP represented employees who are not eligible for Share Grants can opt to participate in an ESOP. Employees can contribute up to 4% of their base salary, made in whole percentages (i.e., multiples of 1%), through payroll deductions on a bi-weekly basis. Hydro One matches 25% of the employee's contribution. Approximately 200 employees participate in this program.

3.2.4 PENSION PLANS - REPRESENTED GROUPS

Regular, full-time employees represented by the SUP and the PWU, are members of the Hydro One Pension Plan (the HOPP). The HOPP is a defined benefit pension plan, and is based on the Ontario Hydro Pension Plan (OHPP) which was established on November 1, 1923. The rights to bargain the terms of the OHPP for represented staff were entrenched during collective bargaining with CUPE Local 1000 (PWU) in 1966 and with the SUP since its inception as a Union in the early 1990's. In 2000, the HOPP was registered and provided a restatement of the existing OHPP terms under the new employer. Although both PWU and SUP workers are members of this plan, there are slight variations in program rules for each group.

PWU HOPP members are currently subject to a retirement formula (age + years of service) of 82 points (referred to as Rule of 82) to be eligible for an undiscounted pension (members with 35 years of service are eligible for an undiscounted pension irrespective of points). The pension benefit upon retirement is based on the average of an employee's highest three years' earnings. On April 1, 2025, the retirement points formula will move to 85 points. For existing employees, the change will apply only to service accrued after this date, and the pension benefit amount will be based on an average of the members' five highest years' earnings. These changes were negotiated during collective bargaining in 2015 and will begin to result in cost savings during the rate period.

SUP represented employees are members of the HOPP, and are divided into two subgroups: plan members prior to November 2005 (known as the legacy plan), and those who joined after November 2005, (known as the new plan). Thus, the rules that apply to the SUP-represented staff depend on whether an employee is in the legacy plan or the new plan.

For those SUP-represented employees in the legacy plan, their pension formula for an undiscounted pension is based on the rule of 82, and their pension benefit amount is based on average of best three years' earnings, similar to the PWU plan. For service earned from April 1 2025 onwards, the pension benefit will be based on average of highest five years' earnings, but the rule of 82 will continue to apply.

Employees under the new plan are currently subject to rule of 85 and their benefit is currently based on the average of the employee's five highest years' earnings. These changes, have been in place since November 17, 2005, and were introduced following a protracted labour dispute between Hydro One and the SUP. All new employees hired into a SUP-represented role on or after that date are subject to these new plan rules. These changes have reduced Hydro One's pension costs.

3.2.5 CUSW

Hydro One negotiates directly with CUSW,[10] and has negotiated a total wage package with CUSW that is below typical market rates for employees that perform similar work, or possess similar skills and certifications, such as employees represented by the IBEW that work in the Electrical Power System Sector.[11] As shown in Table 4 - Comparison of CUSW and IBEW Wages, which compares the CUSW wage rates to those of EPSCA negotiated rates with the IBEW, the total CUSW rate negotiated by Hydro One is $5.73 less (per hour) or nearly 10% lower than the average IBEW rate pursuant to EPSCA-negotiated agreements.

Table 4 - Comparison of CUSW and IBEW Wages

Electrician or Lineman (Journeyperson) – 2020 Rates (Transmission)		
Bargaining Unit	**Base Wage ($)**	**Total Wage Package ($)**
CUSW (Hydro One)	43.90	58.54
IBEW Median (Transmission)	45.41	64.18
IBEW Average (Transmission)	44.87	64.27

3.3 TYPE AND LEVELS OF COMPENSATION PAID TO THE MANAGEMENT & NON-REPRESENTED GROUP

The compensation for this group is based on the principle of creating a pay for performance culture that is aligned with market-based compensation in terms of level and types of pay. Performance-based compensation enhances Hydro One's ability to attract, motivate and retain qualified employees in a competitive labour market. By comparison, a shift away from performance pay in favour of increased base salaries would increase Hydro One's fixed costs and reduce the company's ability to align employee performance with business objectives. As

[10] This is distinct from other construction trades unions that represent Hydro One casual employees (such as the Labourers, or Operating Engineers) who engage in collective bargaining with EPSCA, which acts as an agent for its employer members, such as Hydro One, OPG, and Bruce Power.
[11] IBEW currently represents 14 locals across the province that support work for EPSCA-affiliated employers.

Witness: LILA Sabrin

noted above, based on the updated 2020 benchmarking results described in the Mercer Report, the level of compensation of this segement is below market.

3.3.1 MGT/NON-REPRESENTED COMPENSATION – PROGRAM COMPONENTS

The base pay for non-represented and managerial roles is based on a salary structure that is segmented into core and operations. Creating distinct salary ranges for operations roles provides Hydro One with a competitive advantage, as it can tailor compensation to attract talent for jobs that require specific education, skills and knowledge, which are directly related to electric transmission and distribution systems. This segmentation also ensures that Hydro One does not overpay for skills found more readily in the market, and is in line with market compensation practices. Core services positions require education, skills and/or knowledge not necessarily specific to the utility business, and Hydro One can recruit broadly for such roles given the wider availability of the skill-sets and expertise sought.

Each pay band has a minimum, mid-point, and maximum which are aligned to market. The program is targeted to pay approximately at the market median. This target balances the competing demands of attracting, retaining and incenting management non-represented employees against the need to maintain compensation costs at appropriate levels. Base salaries are adjusted through a merit program (there is no annual across-the-board increase) that recognizes individual performance, behaviours, employee potential, operations or core services segment, internal relativities, and external benchmarking.

3.3.2 PERFORMANCE-BASED COMPENSATION

Management and non-represented employees are eligible for annual incentive-based pay as a component of their total cash compensation. The Short Term Incentive Program (STIP) is designed to reward participants for the achievement of annual team (corporate) and individual performance goals. STIP rewards are based on Hydro One’s performance measured against the balanced Team scorecard, and individual performance measured against goals that are aligned with Hydro One's objectives.[12]

Directors and vice-presidents are eligible to participate in a Long-Term Incentive Plan (LTIP). It is an important component of executive and senior management compensation, enabling Hydro One to retain experienced senior managers who have the skills and experience necessary to execute on Hydro One's goals. Participation in the LTIP is determined annually by Hydro One's Board of Directors and is restricted to key talent. The intent is to provide a balance between short-term performance and long-term success. The LTIP also serves as a retention tool, as awards are paid out 3 years following the grant and is a performance-based award program.

3.3.3 EMPLOYEE SHARE OWNERSHIP PLAN (ESOP)

Management and non-represented employees are eligible to participate in an ESOP. Eligible employees can contribute up to 6% of their base salary and Hydro One will provide a 50% match on contributions to a maximum of 3% of base salary. The introduction of the ESOP is an important element of the total compensation program as it: (i) promotes an ownership mentality amongst employees; (ii) facilitates the attraction and retention of talent; and (iii) enhances employee engagement and productivity through company ownership.

3.3.4 PENSION, BENEFITS FOR THE NON-REPRESENTED GROUP

Non-represented and management employees participate in a Defined Contribution pension plan (DCPP) or the HOPP, if their employment began prior to 2015. As noted above, the DB plan has been closed to new entrants since 2015. Future service changes to the HOPP and the introduction of the DCPP have achieved reduced pension expenses for the company, while still providing employees sponsored plans to save for retirement.

---

[12] The balanced Team scorecard is based on financial and non-financial objectives such as customer satisfaction, operational results, productivity achievements, and safety. The 2021 Scorecard is provided at Attachment 3.

Non-represented and management employees are eligible to participate in core health and dental and flex benefit programs. Hydro One is currently reviewing its benefits programs in an effort to modernize plans that have remained unchanged for more than 15 years. The program is being redesigned based on the principles of market alignment, internal equity, a wellness focus and encouraging internal talent movement from represented to management role, which is a significant challenge for the organization. This benefits program is being redesigned in a manner that maintains cost neutrality to the existing program.

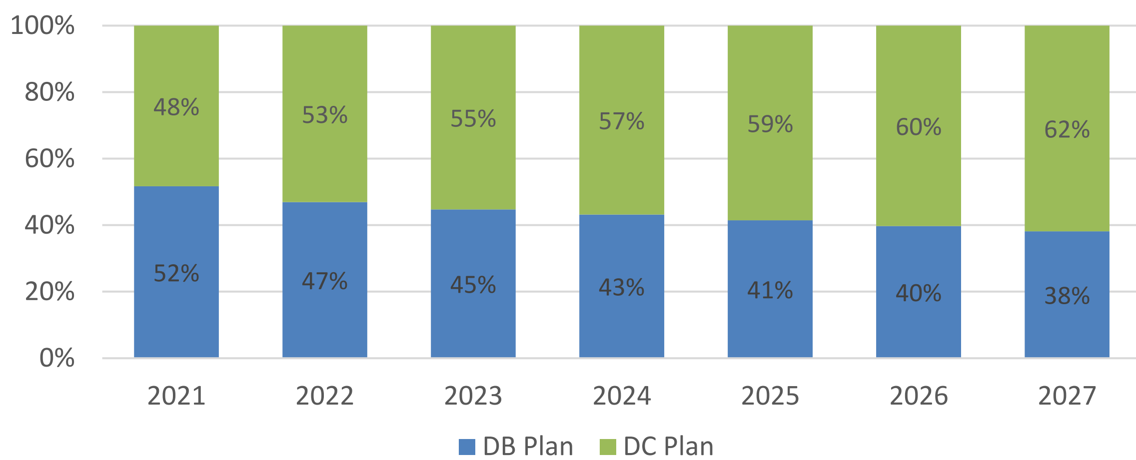


Figure 7: Pension Plan Membership Projections (MGT/N-R)

As illustrated in Figure 7,[13] based on plan member data from 2020, as well as historical retirement turnover trends for the management and non-represented segment, it is anticipated the majority of employees in this segment will be on the DCPP at the beginning of the 2023 rate period.

---

[13] Includes full-time regular employees in the MGT/N-R group who are employed by Hydro One Networks Inc.

Witness: LILA Sabrin

3.4 TYPE AND LEVELS OF COMPENSATION PAID TO EXECUTIVES

3.4.1 EXECUTIVE COMPENSATION

Pursuant to the *Hydro One Accountability Act* (HOAA), Hydro One Networks Inc. (HONI) is not able to recover the compensation costs related to executive positions of Hydro One Limited[14] through rates. This legislation requires the OEB to exclude from rates the compensation costs related to the executives of Hydro One Limited.

As this legislation was passed during the 2018-2022 Distribution rate application process (EB-2017-0049), the OEB directed Hydro One to determine how these changes would impact its revenue requirement. In that application, and in subsequent Transmission applications (EB-2018-0130 and EB-2019-0082), Hydro One elected to voluntarily exclude the compensation for the other four executive officer positions that comprised the Executive Leadership Team (ELT) in place at that time: Chief Legal Officer, Chief Operations Officer, Chief Human Resources Officer, and Corporate Affairs and Customer Care Officer.

In this application, the HOL executive leadership positions, CEO, CFO, and CCDO are excluded from the revenue requirement. The compensation paid for the following executive leadership team positions is also excluded from Hydro One's requested revenue requirement:[15]

- Chief Operations Officer;
- Chief Legal Officer;
- Chief Human Resources Officer;
- Corporate Affairs and Customer Care Officer;
- Chief Safety Officer, and
- Chief Information Officer.

---

[14] HOL executive officers are the Chief Executive Officer CEO, Chief Financial Officer CFO and Chief Corporate Development Officer CCDO.

[15] Chief Legal Officer is an executive of Hydro One Inc., and the Chief Operations Officer, Chief Human Resources Officer and Corporate Affairs and Customer Care Officer, Chief Information Officer, and Chief Safety Officer are executive officers of Hydro One Networks Inc.

Pursuant to the HOAA, a directive was issued by the provincial cabinet in 2018 to establish executive compensation caps, and limit annual increases to market (inflation) rates. The directive set a limit on the level of compensation for Hydro One's CEO. The total compensation for all other executives is limited to 75% of the CEO's maximum direct compensation. Annual increases to executive salaries are also capped at the lesser of the rate of Ontario Consumer Price Index and the annual rate at which total maximum direct compensation may be adjusted for non-executive managerial employees. The directive also limited the compensation of Board members to $80, 000 annually and the Chair of the Board to $120, 000 annually.

In 2019, Hydro One adopted an executive compensation framework that is consistent with the Directive, and which is reflected in the proposed revenue requirement, as follows:

- No other executive's total compensation will exceed 75% of the CEO's compensation;
- Compensation may be adjusted annually by the lesser of the rate of Ontario Consumer Price Index (CPI) and the annual rate of adjustment for non-executive managerial employees; and
- Compensation for the Board of Directors has been decreased to the levels indicated in the Directive.

4.0 PART TWO – RECENT PROGRESS IN MANAGING THE COMPENSATION OF THE REPRESENTED WORKFORCE

As noted further above, overall compensation costs are determined by the size of the workforce relative to its output, the workforce mix, as well as the type and level of compensation paid to the workforce. As 92% of Hydro One's workforce is unionized, the market positioning in respect of the level of compensation predominantly derives from collective bargaining outcomes. Hydro One has and will continue during the rate period (and beyond) to pursue cost-saving opportunities at each round of collective bargaining, consistent with and responsive to feedback from the OEB.

4.1 ADDRESSING THE HYDRO ONE PENSION PLAN (HOPP)

In the benchmarking studies performed by Mercer, the HOPP is identified as a prevailing factor contributing to Hydro One's compensation being above the market median. The HOPP predates Hydro One; it is a long-standing feature of the legacy Ontario Hydro collective agreements. The HOPP has been addressed by Hydro One through both extraordinary actions (negotiation leading to a work stoppage) and a more typical approach (incremental changes negotiated during bargaining). Hydro One's focus on obtaining changes to the pension plans along with at or below industry wage increases, through the collective bargaining process has contributed to the downward trend in its overall market position. Outlined below are the historical and recent changes which have contributed to this improved market position, while allowing Hydro One to maintain a flexible, efficient, and appropriately-size workforce.

Pension plan formula changes were introduced for SUP represented staff hired on or after November 17, 2005. The average earnings period increased from 36 to 60 months and the requirement for an undiscounted pension increased from 82 to 85 points. The indexing formula of both the post-2005 SUP plan and the management plan was adjusted - the indexation rate was reduced from 100% to 75% of CPI. Hydro One obtained these SUP-related amendments through arbitration following a work stoppage that lasted over three months.[16]

The changes to the SUP pension plan that affected employees hired on or after November 17, 2005 constitute an increasingly significant source of savings as a greater percentage of SUP represented employees come under the new plan. As shown in Figure 8 below, the membership in the legacy plan will continue to diminish over the course of the rate period.

[16] In the round of bargaining that preceded this work stoppage, Hydro One had sought a two-tier wage schedule, improved contracting provisions, and a revision of base hours from 35 to 40, in addition to pension changes. Following this protracted work stoppage and subsequent government imposed arbitration, only the pension plan rule changes noted above were achieved.

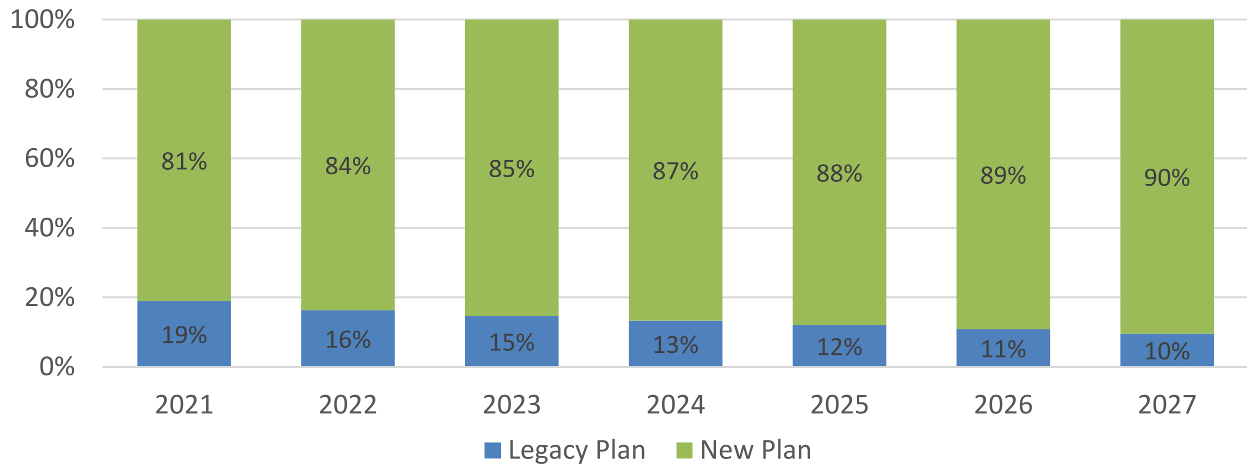


Figure 8: Decreasing Share of SUP Members on Legacy Pension Plan

The estimated cost savings from the changes in the SUP pension plan discussed above totalled $29M from 2010 to 2020, and are projected to be approximately $46.3M from 2021 to the end of 2027. The annual amounts that comprise this total are shown in Table 5 below.

Table 5 - Estimated Annual SUP Pension Plan Savings Due to 2005 Plan Changes

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
Savings	$1.5M	$1.8M	$2.1M	$2.3M	$2.5M	$2.7M	$2.8M	$2.7M	$3.0M	$3.7M	$3.9M	$29.0M

Year	2021	2022	2023	2024	2025	2026	2027	Total
Savings	$4.6M	$5.6M	$6.1M	$6.7M	$7.2M	$7.8M	$8.3M	$46.3M

Over a period of many years, Hydro One has also negotiated increases to member contribution rates (the employee's contributions to the plan), though often it is government intervention that has enabled meaningful change. When the Provincial government decided to proceed with an Initial Public Offering (IPO) of Hydro One Limited in 2015, this resulted in joint negotiations with OPG for the PWU agreement at a central table where the mandate and focus was to settle monetary items. During this round of bargaining, the provision of Canadian Controlled Private Corporation (CCPC) shares provided a strategic advantage to Hydro One's bargaining position

Witness: LILA Sabrin

because of the tax advantages of this form of equity,[17] which conferred substantial benefits to the PWU and SUP represented employees who were eligible to receive this compensation, as well this resulted in ongoing cost-savings for Hydro One.

This form of compensation has inherent cost savings (in comparison to base wage increases), as it is only provided to a defined class of employees who meet the eligibility requirements,[18] and is time-bound (share grants will cease to be paid in 2028 and 2029). Thus, the group of PWU and SUP represented employees who receive share grants will diminish over time, and the long-term impact to pensions is mitigated due to lower increases in base wages. Lump sum payments were also provided for both groups during the 2015/2016 rounds. This meant that Hydro One had the leverage to renew its agreements with the PWU and SUP for wage increases that were less than other utility peers for the years 2015-2018 (the PWU renewal agreement) and 2016-2019 (SUP renewal agreement).

Moreover, Hydro One was able to offer equity compensation in exchange for the PWU accepting further changes to Pension Plan contribution rates, as well as significant changes to the rules of the plan. These changes are scheduled to take effect in 2025, and apply to future service accrual and will have a cost-savings impact on the HOPP, as estimated below. Progress has also been achieved in past negotiations with the SUP, during which similar changes to the pension plan[19] were obtained (as well below-market wage increases of 0.5% per year) by leveraging ESOP and Share Grants.

---

[17] CCPC shares are a unique form of share that can only be issued before an organization undergoes an IPO. The value of the shares is not required to be included on the individual recipient's tax return in the year the share is issued, but rather only in the year the share is sold. Once shares are sold, Hydro One must report the taxable benefit on the recipient's T4. However, if the share has been held by the recipient for at least two years, the recipient can claim a tax deduction of 50% of the value of the shares sold.
[18] In the 2015/2016 round, only PWU and SUP represented staff who were contributing members to the Pension Plan in 2015 (April and September, respectively) were eligible to receive share grants.
[19] Best five years' earnings instead of three, and increased employee contribution rates.

In 2025, the PWU pension plan will be amended to align with provisions of the new Society pension plan, and the legacy Management defined benefit plan. These changes will entail significant savings for Hydro One, as noted in Table 6 below.

For the period from the end of March 2025 to the end of December 2027, the estimated costs avoided as a result of plan changes discussed above for PWU members total $21.5M.

Table 6 - PWU Pension Plan Savings

Year	2025 (Mar. 31 to Dec. 31)	2026	2027	Total
Savings	$5.6M	$7.8M	$8.1M	$21.5M

Furthermore, incremental changes to contribution rates negotiated during various rounds of bargaining have and will continue to yield cost savings, and will help to improve the relative competitiveness of Hydro One's level of compensation. In recent years, Hydro One has negotiated significant increases to employee contribution rates.

While this progress made by Hydro One has been over multiple rounds of bargaining and has been incremental, the overall cost impact is significant. Since 2012, the proportion of pension costs apportioned to Hydro One has been reduced by nearly 25%, which aligns with the gradual increase in employee contributions rates as evident from Table 7 below.

Witness: LILA Sabrin

Table 7 - Pension Contribution Rate Changes PWU & SUP

	Pre-2011	Pre-2013	April 1 2013	April 1 2014	April 1 2015	April 1 2016	April 1 2017	April 1 2018 to present
PWU	**4% Up to YMPE + 6% Beyond YMPE**	4.5% + 6.5% (Apr 1 2011 to Mar 31 2013)	5.5% + 7.5%	6.25% + 8.25%	7.25% + 9.25%	8.25% + 10.25%	8.75% + 11.25%	**8.75% + 11.25%**
SUP - Legacy Plan	**4% + 6%** (Up to Nov 30 2010)	4.5% + 6.5% (Dec 1 2010 to Mar 31 2013)	5.25% + 7.25%	6.25% + 8.25%	7.0% + 9%	7.5% + 9.5%	8.25% + 10.25%	**8.75% + 11.25%**
SUP - New Plan	**4% + 6%** (Up to Mar 31 2013)	4% + 6% (Up to Mar 31 2013)	4.75% + 6.75%	5.75% + 7.75%	6.5% + 8.5%	7.0% + 9%	7.75% + 9.75%	**8.25% + 10.75%**

**YMPE: Yearly Maximum Pensionable Earnings.*

For years 2017 to 2027, the estimated funding (cash) savings as a result of increasing SUP and PWU member contribution rates is $46.4M. The annual figures that comprise this total are provided in Table 8 below.

Table 8 - Estimated Savings from PWU & SUP Pension Contribution Rate Changes[20]

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Savings	$2.2M	$4.9M	$5.7M	$5.8M	$5.8M	$6.1M	$6.5M	$6.7M	$6.9M	$7.1M	$7.3M	$65.0M

4.2 COMPENSATION COST REDUCTIONS DUE TO SHIFT TO DEFINED CONTRIBUTION PLAN

In 2015, Hydro One closed the Management/non-represented defined benefits pension plan, thereby reducing related compensation costs. This decision aligns with the market trend of introducing defined contribution pension plans as the primary form of retirement program. As expected, this program change will continue to yield savings as the demographics of the non-

[20] Estimated savings compare employee contributions both actual (2016-2020) and estimated (2021 - 2027) to employee contributions rates in effect as of April/May 2016. The table outlines the dollar value associated with the percentage increases in employee contribution rates introduced after 2016.

represented group continues to shift through retirements and voluntary turnover. As noted above, anticipated turnover in the non-represented workforce is expected to result in a shift in the number of management/non-represented employees in the legacy defined benefit program.

4.3 IMPACT OF COLLECTIVE BARGAINING ON BASE WAGES

Hydro One has been able to obtain reductions in compensation that provide future cost-savings. In the 2015 round of bargaining for both PWU and SUP, Hydro One achieved cost savings through negotiating wage increases that were below-market and less than inflation in the 2016-2018 period.

4.3.1 PWU NEGOTIATED WAGE INCREASES

- 2015-2018 Renewal Agreement: 1% annual wage increases over three years: April 1, 2015; April 1, 2016; and April 1 2017.
- 2018-2020 Renewal Agreement: 1.8% on April 1, 2018; 2.0% on April 1, 2019; and 0.6% on January 1, 2020.
- 2020-2023 Renewal Agreement: 1.9% on April 1, 2020; 2.0% on April 1, 2021; and 2.2% on April 1, 2022.

4.3.2 SUP NEGOTIATED WAGE INCREASES

- 2016-2019 renewal agreement: 0.5% annual wage increases in each of the three years covered by the agreement on April 1, 2016; April 1, 2017; and April 1, 2018.
- 2019-2021 Renewal Agreement: 2.0% on April 1, 2019 and 2.0% on April 1, 2020.

4.3.3 COMPARISON WITH MARKET WAGE INCREASES

The above rounds of negotiations with the PWU and SUP successfully resulted in obtaining annual wage increases that compare well to those negotiated by market peers and OH successors. With exception of 2020 for PWU, negotiated increases have been at or below the market median of other utility and OH successor employers who negotiate with the PWU and the SUP, as illustrated below in Figure 9 and Figure 10. Such moderate wage increases entail both immediate cost savings, as well as a reduction in long term costs associated with the pension plans, the ongoing costs of which are impacted by increases to base salary.

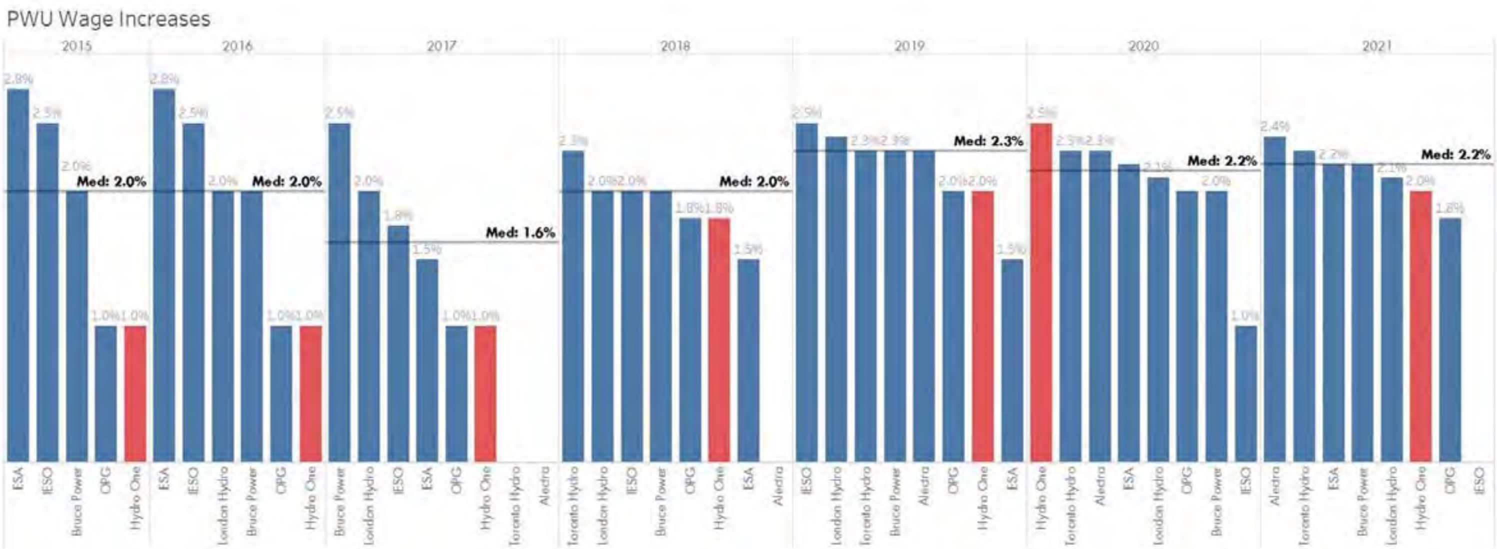


Figure 9: PWU Negotiated Rates for Market Comparators

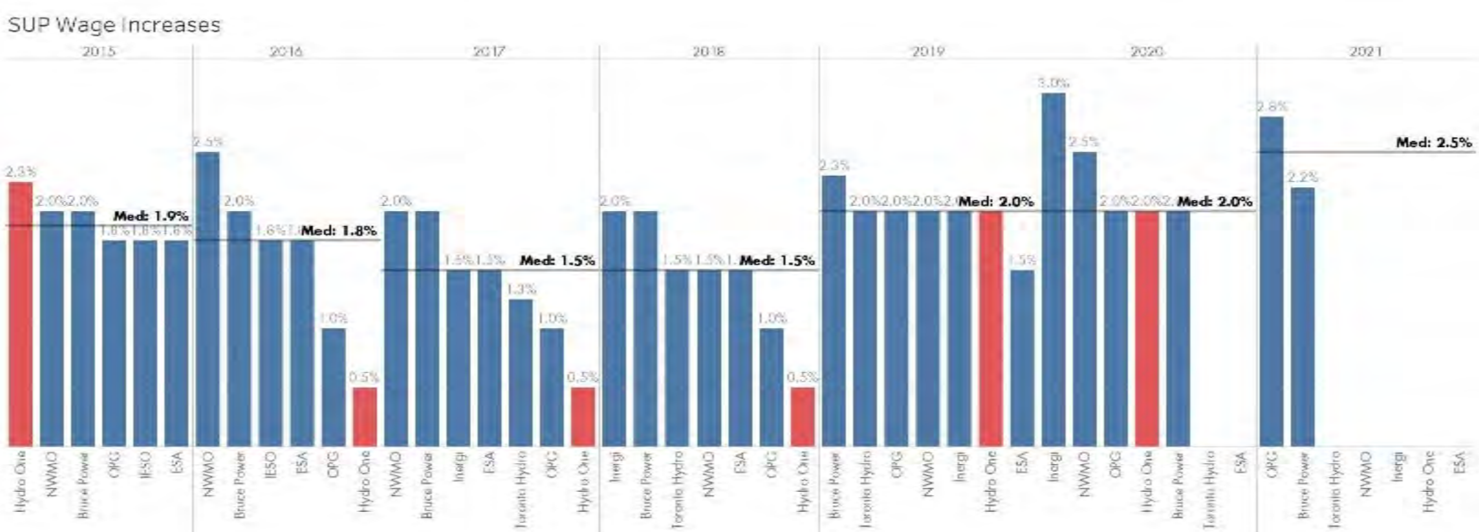


Figure 10: SUP Negotiated Rates for Market Comparators

Witness: LILA Sabrin

4.4 BARGAINING CONTEXT – NEGOTIATED CHANGES TO SUPPORT FLEXIBLE RESOURCING

In order to effectively manage and limit total compensation costs, Hydro One's resourcing plans ensure regular staffing levels are reasonable and appropriate to deliver ongoing work and are not sized to meet incremental work demands. This resourcing approach is contingent on the ability to meet incremental work demands through contracting out, utilizing casual labour, and limiting the growth of regular headcount by efficiently deploying the existing workforce. The opportunities to contract out work, rely on temporary influxes in casual labour and maximize efficiency from existing resources are primarily due to previously negotiated changes to the collective agreements

Successive rounds of negotiations since the OH demerger have focused on enabling efficiency or modernizing legacy compensation programs that deviate from compensation trends in the labour market. Through negotiation, Hydro One has achieved workforce flexibility that enables the organization to supplement the regular workforce with the casual workforce and use external resources. The following sections summarize how this flexibility was achieved and the benefits it provides.

4.4.1 PWU-RELATED CHANGES TO LEGACY AGREEMENT

4.4.1.1 INTRODUCTION OF THE PWU HIRING HALL (HH)

To execute the Investment Plan, Hydro One will require additional resources from the PWU HH. Hydro One introduced Appendix A (HH) through the collective bargaining process shortly after the demerger as a way of having a contingent construction-type workforce (casual labour) for incremental work, such as maintenance-related, specialized, and/or project-based tasks. These workers do not join the Hydro One pension or benefit plans. Once the work is complete, these workers can be laid off with no severance or other entitlements owing. Using the HH model allows Hydro One to recruit and build a talent pipeline without making a long-term employment commitment.

PWU HH employees are provided a percentage of their base hourly rate in lieu of paid leave (statutory and vacation days), and a flat hourly amount in lieu of pension and benefits. These amounts are remitted directly to the PWU and the union administers the group Retirement Plan and Health Plan for these employees. Given the amount of paid leave and other benefits that regular PWU employees are eligible to receive, a comparison of costs on a per hourly basis indicates that PWU HH employees are less costly to Hydro One than regular PWU-represented employees.

As previously stated, apprentices at Hydro One are members of the PWU HH during the term of their program. These workers typically have to complete their apprenticeship hours, and apply and be selected to a full-time regular position, as there is no guarantee of ongoing employment.

Completion of an apprenticeship program typically takes four to five years. Hydro One is not required to guarantee ongoing work at the outset of an apprentice's training. Instead, apprentices apply for regular positions once they complete their program. Given that work program demands will fluctuate, this model provides flexibility to hire qualified trades persons as required, not four to five years in advance of potential work. This apprenticeship process also allows Hydro One to manage certain employment-related costs, given the unique employment terms that apply to PWU HH represented staff.

4.4.1.2 PWU MIDTERM 50

Since the OH demerger, Hydro One has sought and achieved flexibility pertaining to contracting out work that historically was subject to the jurisdiction of the PWU. The legacy agreements from Ontario Hydro contained extremely restrictive contracting-out clauses that protected the jurisdiction of the union. Prior to 2001, any on-going work that was within this jurisdiction could only be performed by outside firms if the union consented to a Purchased Services Agreement (PSA), or one was awarded by an arbitrator. PSAs cover the contracting out of certain work for a discrete period of time and for a designated project. Negotiating PSAs became a costly and timely process. Due to a lack of sufficient labour, delays in obtaining PSAs frequently slowed essential work with resulting impacts on customers, costs and timelines.

As indicated above, Hydro One then negotiated Mid-Term 50, so that certain types of work could be contracted to third parties. This novel arrangement is atypical in collective agreements because it permits the contracting out of a wide variety of work. Typical contracting out arrangements require individually-negotiated agreements. This arrangement permits the contracting out of entire categories of work: snow removal, janitorial, heavy and/or specialised equipment operation (such as hydrovac, float trucks, backhoe), minor fleet maintenance, and ensures Hydro One can contract out work to organizations that specialize in these areas. This bargaining achievement eliminated the need to constantly re-negotiate specific types of work (or arbitrate the validity of contracting it out) that recurred intermittently, and are costly to execute due to the seasonal nature of such work or the specialized equipment it requires.

4.4.1.3 PWU CABLE LOCATES - PSA

Another example of the flexibility Hydro One has achieved through collective bargaining is the Cable Locates PSA; negotiated in 2015 (the savings from this change are discussed in SPF Section 1.4). In most circumstances, when cables need to be located, more than one type of underground equipment is involved (e.g. gas lines, water and sewer pipes and electricity and telecommunications cables). This led to the creation of Ontario One Call, where a single organization consolidates locate requests. This separate entity owns the infrastructure, and completes all the required locates at once, thereby lowering costs for all the participating utilities.

In the past, cable locates were performed by PWU-represented employees. This meant that Hydro One was responsible for managing the infrastructure to receive locate requests, dispatch employees to perform the work and ensure all associated administrative work was done. This also prevented Hydro One from participating in the Ontario One Call initiative. Given the PWU collective agreement and the associated work jurisdiction, Hydro One was unable to take advantage of the cost savings and efficiency gains associated with Ontario One Call. Once the Cable Locates PSA was negotiated and entered into, Hydro One could allow Ontario One Call to do this work on its behalf at a significantly reduced price. Further, the staff that would have performed locates could be redeployed to other work and Hydro One no longer had to maintain the infrastructure required to dispatch, perform and track locates.

4.4.1.4 SUP-RELATED CHANGES

A significant shift in Hydro One's labour relations history with the SUP began with the alteration of the dispute mechanism for resolving bargaining impasses which enabled the possibility of a work-stoppage. Prior to the 2005 round of bargaining, the Voluntary Recognition Agreement (VRA) with the Society did not allow for a strike/lock-out regime. In the previous round of negotiations, Hydro One successfully advocated for an agreement term length sufficient to ensure that notice could be given and the next round of negotiations would be done under a strike-lock-out regime. Hydro One was the first successor to move to a strike-lock-out regime with the SUP and, as such, has been able to address issues related to the cost of pensions. The removal of the previous mediation-arbitration regime changed the bargaining relationship, as demonstrated through the incremental changes discussed below.

4.4.1.5 CONTRACTING-OUT – REVISIONS TO THE SUP AGREEMENT

The ability to contract out work covered by the SUP collective agreement has been a focus of bargaining, and Hydro One has made progress on securing contracting flexibility, relative to other successor companies. At the time of the demerger, the SUP collective agreement contained restrictive language that limited Hydro One's ability to contract out work -- Article 67 of the collective agreement included a bilateral process for determining the assignment of work (referred to at the time as a purchased service), and what factors should be used to evaluate the use of external resources.

Starting in 2013, the previous multi-page article was eventually replaced with a single clause: "No employee will be laid off as a direct result of contracting out." This gives Hydro One flexibility to contract out work without any additional requirements beyond this clause. This allows Hydro One to retain services in engineering and construction for projects that are not directly related to the type of engineering and design intrinsic to electrical power systems, and that require a high level of expertise and certification but are intermittent in nature. This required expertise and certification (such as the engineering work related to construction of buildings) is typically specialized, and these types of work are not core to Hydro One. Staffing internally would require a 10-15 year trajectory of hiring, training, and experience to deliver the same level of engineering that can be obtained through contracting out. As such, the flexibility to contract out is essential to cost-effectively execute these types of work. This use of external resources does not displace existing staff but rather allows Hydro One to assign specialized/shorter-term work to firms that have industry-leading expertise.

The terms and conditions of employment for a regular Society employee are somewhat inflexible in light of the restrictive and costly downsizing provisions. Thus, external resourcing flexibility is also consistent with and helps to further Hydro One's long term interests in managing compensation costs through limiting FTE growth to the levels necessary to support ongoing work.

4.4.2 CUSW – CONTRACTING FLEXIBILITY

Hydro One has also achieved contracting flexibility with CUSW and specifically, the ability to utilize non-CUSW affiliated contractors. Although Hydro One has already secured competitive total wage packages, this additional flexibility is required for Hydro One to enter Engineer, Procure and Construct (EPC) contracts. EPC contract arrangements provide efficiency and cost benefits when compared to Hydro One performing all the work internally. To make use of these arrangements, appropriate contracting out flexibility is required within all union jurisdictions.

In most cases with construction contracting, the contractors need to be affiliated with the same unions who would perform the work if it had been completed by Hydro One. However, this is not the case with CUSW as Additional contracting flexibility has been achieved with CUSW. The flexibility is important, as Hydro One's ability to use IBEW-affiliated and other contractors leads to a larger contractor pool and more competitive contractor bids. While contracting out in the construction sector is a normal business practice and is supported by the unions, Hydro One's unique arrangement with CUSW ensures the entire marketplace of electrical contractors can be leveraged.

4.4.3 WORKFORCE FLEXIBILITY: MANAGING RESOURCES DURING A PANDEMIC

At the outset of the Covid-19 pandemic, and prior to the provincial government's assessment of what work would be deemed essential, Hydro One was required to adjust staffing levels quickly and in a cost-effective manner.

Approximately 1,100 casual employees were stood down in early April 2020 as a result of provincial government measures taken at the outset of the pandemic. A series of agreements to prolong the stand-down period (as opposed to imposing the pre-existing layoff period which creates an administrative burden, and delays the process of re-employing the casual trades workforce after a period of work slowdown) were obtained with CUSW and the building trades unions subject to EPSCA negotiated agreements. These agreements guaranteed that these employees could be quickly returned to work once the policy decisions on essential workers had been confirmed, and additional safety protocols implemented. Such an unforeseen work slowdown was executed with minimal cost and disruption to Hydro One.

A similar advantage was obtained by negotiating with the PWU for scheduling flexibility to contend with the pandemic. Letter of Understanding (LOU) # 107 provided greater flexibility in: (i) the use of composites crews (crews staffed by a mix of regular employees and HH members); (ii) work assignments outside of base classifications where appropriate; and (iii) expanding the scope of flexible working hours and adapting to local work requirements. In the most recent round of PWU bargaining that concluded in the fall of 2020, the parties agreed to maintain this LOU for the term of the renewal agreement.

4.4.4 EXAMPLE OF EFFICIENCY AND COST CONTAINMENT THROUGH ARBITRATION: FORESTRY TECHS & DATA LINE PATROL WORK (ARBITRATION)

Another example of workforce flexibility relates to the assignment of forestry work. Hydro One took steps to reduce the number of staff required to perform data lines patrol work by assigning it to Forestry Techs who were already required to observe and record vegetation interference with poles. Given that their work requires pole observation, it made sense to also task these workers with data lines patrol work, rather than utilize additional staff, which was seen as a redundancy. The PWU resisted the assignment of certain tasks to these technicians, requiring Hydro One to defend its work assignment at arbitration. Although this approach is not directly correlated with a specific productivity savings initiative, the elimination of the redundancy enables efficient outcomes and avoids cost by ensuring staffing levels do not rise unnecessarily.

5.0 PART TWO – LABOUR RELATIONS APPROACH & PLAN TO GET TO MARKET GOING FORWARD

Hydro One’s labour relations approach must recognize the operational realities of the company, such as:

a) The nature of the work requires a high degree of skill, and bears inherent risks to health and safety which must be managed and mitigated;
b) Hydro One’s aging workforce presents ongoing turnover risk, and the need to ensure skilled workers are ready to replace retirements from the existing workforce;
c) Hydro One has an ongoing need to compete for talent with other successor companies and other utility peers;
d) Geographic considerations, including the fact that assets and customers are spread across the province. As such, large segments of Hydro One’s workforce are expected to be able to work in various conditions, and be deployed across the province as required to service customers, address trouble calls and restore larger-scale outages;
e) The nature of Hydro One’s operations requires an integrated workforce which can be assigned to work on both Transmission and Distribution;

f) The need to upgrade and modernize Hydro One's large and highly complex system of assets; and

g) The nature of Hydro One's business is such that the work must be performed locally and is an essential service.

The following additional factors exist in respect of the unions that represent Hydro One employees, which it must also take into account:

i. Much of the work required to operate Hydro One's distribution and transmission business cannot be relocated or centralized;

ii. The SUP and PWU represent workers at all the Ontario Hydro successor companies, as well as some local distribution companies, and have ongoing interests in maintaining parity amongst these bargaining units, despite the divergence in interests and size of the employers represented;

iii. Membership in these unions is spread throughout the province, yet, with exception of the casual trades unions (those agreements negotiated through EPSCA), have standardized base wages; and

iv. These unions are well-funded and stable, given the relative security of the workforces which they represent (as opposed to sectors such as automotive manufacturing, or communications, where membership has decreased in the province).

Each of these considerations - the legacy agreements inherited, the context of labour relations in Ontario, related legislation, and the realities of Hydro One - impact the approach to collective bargaining and mean, as a practical matter, that changes are required to be pursued incrementally through successive collective agreement renewals.

Despite the constraints and challenges imposed by these realities, Hydro One has in recent years bargained successfully to achieve incremental changes to the collective agreements described above – which has enabled the workforce flexibility necessary to achieve efficiency and productivity gains detailed in this application, and has contributed to the improvement in Hydro

One's level of compensation benchmarking results. As described, a key component of Hydro One's resourcing strategy is to contract out incremental work, and use non-regular labour when appropriate to cost effectively execute its work program. This approach to managing long-term resource cost depends on a high degree of adaptability in resourcing options.

Negotiated outcomes with union partners must continue to maintain and, as necessary, expand Hydro One's ability to efficiently assign work internally and appropriately rely on external resources, while also continuing to address the costs of the salaries and benefits paid to existing regular full-time employees.

5.1 COLLECTIVE BARGAINING CONTEXT FOR HYDRO ONE'S LABOUR RELATIONS APPROACH & PLAN GOING FORWARD

Collective bargaining is an iterative process and outcomes occur within the overall context of the electricity sector in Ontario. The PWU and SUP negotiate with electricity sector employers year in and year out, and outcomes from these negotiations affect Hydro One. Ontario's electricity sector employers constitute a mix of public and private sector companies with divergent goals; their bargaining positions reflect their own particular operational needs and priorities that go beyond wages and benefits. However, irrespective of the employer with whom they are negotiating, the unions seek similar outcomes for their membership – improved wages and benefits, and job security – and this has an impact on negotiations with Hydro One.

When negotiations fail to yield an agreement, interest arbitration is typically used to resolve the impasse. Through arbitration, the likelihood of obtaining significant changes is diminished, as arbitration is intended to result in an agreement that aligns with what the parties would have likely achieved through negotiations, and takes into account other contemporaneous union wage agreements. Agreements obtained through arbitration then set expectations for the unions as to what they should aim to achieve in bargaining with other employers.[21]

As experienced during in the 2005 SUP bargaining round which ended with a strike, the use of firm tactics may ultimately place the outcome of collective bargaining in the hands of an arbitrator. This form of dispute resolution inherently limits Hydro One's ability to push for and achieve significant reforms to traditional forms of compensation, including immediate changes that reduce compensation costs.

The market position of Hydro One's compensation is also impacted by unrelated events that affect its market peers in the utility sector. For example, the recently passed *Protecting a Sustainable Public Sector for Future Generations Act* (known as Bill 124) imposes a 1% cap on the compensation of employees in the provincial public sector. This legislation currently applies to Ontario Hydro successor companies that bargain with the PWU and SUP such as Ontario Power Generation (OPG), and the Independent Electricity System Operator (IESO). These restrictions are set to remain in place through 2024, and will possibly continue throughout the rate period.

Although Hydro One is not subject to this legislation, it is an external event that is both outside of Hydro One's control and unrelated to its efforts to control compensation costs, yet may impact its market position.

In conclusion, absent coordinated intervention such as in 2015, it is very challenging to slow the rate of base salary increases and make fundamental changes Hydro One's pension plans for the PWU and SUP. In a stable work environment, such as the Ontario energy sector, where the work cannot be relocated and employers are not facing existential financial distress, collective agreements rarely undergo major changes. Progress can be and has been achieved through

[21] Chaykowski, Richard P. "Time to Tweak or Re-boot? Assessing the Interest Arbitration Process in Canadian Industrial Relations." Commentary No.539. April 2019: Human Capital Policy. CD Howe Institute. Page 14. (Provided as Attachment 4 to this Exhibit)

incremental changes. This is the context in which future rounds of collective bargaining will continue to take place.

5.2 ACHIEVING MARKET LEVEL COMPENSATION

Even before the OEB's most recent decision directing Hydro One to include a plan to bring its levels of compensation in line with market median (EB-2019-0082), Hydro One was focused on the objective of managing compensation costs consistent with prior OEB feedback on this issue. The company remains committed to achieving market-based levels of compensation paid to employees, and to efficiently managing its overall compensation costs, consistent with its strategic objectives. Hydro One recognizes its responsibility to deliver service in the most cost-effective manner reasonably possible.

As noted above, Mercer defines at-market as within +/- 5% of the P50 market median. In light of progress that has been made in recent years, Hydro One is currently 4% above the at-market range. Hydro One intends to take steps to further close this remaining gap through its labour relations strategy going forward.

The Management and Non-represented segment is already 4% below the P50 market median, and therefore is at-market. The Energy Professionals segment is 11% above P50 market median or 6% above the at-market range. The Trades and Technical segment is 10% above P50 market median or 5% above the at-market range. Based on these results and the objectives stated above, the focus of Hydro One's plan to get to market levels of compensation is on the represented segment of its workforce.

In recent negotiations, Hydro One has pursued changes to core components of represented compensation and increased flexibility to assign work in collective bargaining. Previously negotiated changes such as lower-than-market wage increases that reduce pension obligations, lump-sum payments, equity grants or the changes to both SUP and PWU plans, will have an impact going forward and are expected to improve market positioning over multiple studies as employee demographics change. Pension contribution changes that were negotiated between 2005 and 2015 have significantly contributed to the movement towards market median shown in the Mercer Report; as have the below market wage increases Hydro One has been able to negotiate.

Hydro One is committed to achieving market levels of compensation, and anticipates being able to make further progress in this regard during the rate period. Successive rounds of collective bargaining will likely be required to align Hydro One's level of compensation to the market (+/-5%) on an overall basis, having regard to the context in which Hydro One operates. As an integral part of its plan to achieve market compensation, Hydro One has determined its strategy going forward in respect of upcoming rounds of bargaining to advance both near and long-term objectives. Given the highly confidential nature of Hydro One's future labour relations strategy, this strategy for upcoming rounds of bargaining is described in the confidential appendix to this exhibit (Attachment 5).

Hydro One also notes that compensation benchmarking focused solely on levels of compensation paid to employees does not account for efficiency gains achieved through greater workforce flexibility or through the cost-avoidance achieved via longer-term arrangements like MT-50 and the SUP's contracting-out language discussed above. The important role that workforce flexibility plays in the execution of Hydro One's work programs - and associated cost efficiencies - must also inform Hydro One's approach to collective bargaining and labour relations.

This page left blank intentionally.

Witness: LILA Sabrin

PENSION AND BENEFIT COSTS (OPEBs)

This exhibit describes Hydro One's pension and other post-employment benefit costs (OPEB) for the 2023-2027 period, for the Remotes business, and the manner in which those costs have been forecasted for the purpose of recovery. As pension and OPEB costs are an important part of the overall compensation that is provided to attract and retain skilled employees for the purpose of providing regulated service, Hydro One has historically been permitted to recover such costs through rates. Hydro One's pension and OPEB costs over the test period have been appropriately forecasted in a manner consistent with prior OEB approvals and based on expert actuarial valuation.

1.0 DEFINED BENEFIT PENSION COSTS

Remotes is a participant in the Hydro One Pension Plan (the DB Plan). The DB Plan is a contributory, defined-benefit pension plan. The DB Plan is registered pursuant to the *Pension Benefits Act* (Ontario) and the *Income Tax Act* (Canada) and is not subject to income tax. Plan members include represented employees of the Power Workers Union (PWU), the Society of Energy Professionals (SUP), as well as non-represented Management Compensation Plan (MCP) employees who were hired and met the eligibility requirements to join the plan no later than September 30, 2015, and pensioners who were employees, and pensioners who are beneficiaries or surviving spouses of employees or pensioners.

The DB Plan covers Hydro One Inc. and its subsidiaries. The DB Plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for Remotes, the DB Plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded on Remotes' financial statements.

Networks recognizes pension expense on a cash basis and considers this method to be more beneficial to its customers than the accrual basis because it generally results in lower yearly costs recovered through rates. This method also results in less volatile forecasting of the cost, and it is thus more consistent with actual expenses for the applicable years. Additionally, the cash basis reflects the statutory amounts that Networks has to contribute to the DB Plan.

The OEB has previously accepted cash payments related to pension obligations to be included in revenue requirement (RP-1998-0001) for Hydro One and its subsidiaries, and has approved full recovery of these cash payments in various proceedings since then. The OEB and intervenors accepted this treatment for Remotes' pension obligations in EB-2017-0051.

For Remotes, the charge to be recovered through rates in 2023 is $1,110k provided in Table 1 below.

Table 1 - Pension Costs (*in thousands $*)

Category	Board Approved	Historic (Actual)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
OM&A	491	543	437	486	465	692	693
Capital	196	217	256	225	258	361	417
Total	**687**	**760**	**693**	**711**	**723**	**1,053**	**1,110**

2.0 ACTUARIAL VALUATION

For DB plans, there is a requirement to complete and file a full actuarial valuation at a minimum every 3 years. Management can, at its discretion, file these valuations more frequently. The Tri-Annual Actuarial Valuation report for the DB Plan as at December 31, 2018 establishes the contribution rate for 2019, 2020 and 2021. In September 2019, Hydro One filed this actuarial valuation with the Financial Services Regulatory Authority of Ontario (FSRA), formerly FSCO. Hydro One's next Tri-Annual Actuarial Valuation for the DB Plan is required as at December 31, 2021 and must be filed by September 30, 2022. The valuation results will depend on investment returns, changes in benefits, and actuarial assumptions.

The December 31, 2018 valuation showed that the Plan had a deficit position of $2,595M on wind-up basis[1] as of December 31, 2018[2]. Based on that valuation, starting in 2019, the required contribution rate for the DB Plan (employer normal actuarial cost as a % of payroll) was set at 11.4% of base pensionable earnings.

During 2019, 2020 and 2021, actual total Hydro One contributions were $73M, $69M, and $74M, respectively. Actual contribution requirements in 2022 may differ depending on the level of base pension earnings used to compute the monthly contribution.

3.0 DB PENSION PLAN GOVERNANCE AND PERFORMANCE

Hydro One Inc. is the Plan sponsor and administers the pension assets and obligations of the Plan. As at December 31, 2021, the DB Plan had a reported net asset value of $8,653M as per the audited financial statements and about 13,932 members. Approximately 43% of the DB Plan's members are active. The remaining DB Plan members are inactive, either retired, beneficiaries of retirees, former employees eligible for a deferred pension, or members on long-term disability.

The going concern and solvency funded statuses are the primary ways that Hydro One can assess the DB Plan's success at providing benefit security to DB Plan members and contribution funding stability to Hydro One. Funding ratios greater than 100% indicate that the DB Plan holds more than a sufficient amount of assets to meet the long-term obligations of the DB Plan. The DB Plan ended 2021 with a going concern funded ratio of 118% (2020: 110%) and a solvency funded ratio of 114% (2020: 111%).

---

[1] Wind-up basis valuations assume the plan is terminated and wound up on a specified date with all members' benefits being settled through either a purchase of annuities or the transfer of commuted values and the interest rates tend to fluctuate on a monthly basis. The assumptions therefore reflect the estimated cost of annuities and the prescribed assumptions for commuted values. The value of all benefits, including future indexation of benefits, is included in a wind up valuation.

[2] This valuation also showed that the DB Plan had a surplus of $1,425M on a going-concern basis, however, whether or not there is a surplus on a going-concern basis is not relevant to the question of whether a contribution is required in a given year by Hydro One.

4.0 DEFINED CONTRIBUTION PENSION PLAN

Effective January 1, 2016, Hydro One introduced a Defined Contribution Pension Plan ("the DC Plan"). The DC Plan is available for all new full-time and part-time MCP employees, who meet the eligibility requirements to join a pension plan on or after October 1, 2015 and who are not eligible to participate in the DB Plan. Members are able to join the DC Plan on the later of January 1, 2016 or the date they are made probationary or regular employees. The DC Plan allows eligible employees to contribute up to 6% of their pensionable earnings with a 100% match of contributions by Hydro One.

5.0 OTHER POST-EMPLOYMENT BENEFITS ("OPEB") COSTS

OPEB benefits cover eligible represented employees of the PWU and SUP, as well as MCP employees, pensioners who were previously employees and pensioners who are beneficiaries or surviving spouses of employees or pensioners (see Exhibit D, Tab 4, Schedule 1, Attachment 1). Hydro One uses the accrual method for accounting of OPEB. The accrual method is appropriate because it reflects the costs incurred during the time period and, as such, more accurately attributes those costs to the appropriate ratepayers. Table 2 summarizes historical and forecast OPEB costs included in rates.

Table 2 - OPEB Costs Included in Rates (*in thousands $*)

Amounts Included in Rates	Board Approved 2018	2018	2019	2020	2021	2022	2023	Total
OM&A	909	813	945	1,308	997	1,257	1,292	**6,612**
Capital (Note 1)	363	326	553	302	332	360	417	**2,290**
Total	**1,273**	**1,139**	**1,498**	**1,610**	**1,329**	**1,617**	**1,709**	**8,902**
Paid Benefits Amounts	605	144	182	272	258	383	394	**1,633**
Net Excess - amount included in rates vs. amount actually paid	667	995	1,316	1,338	1,071	1,234	1,315	**7,269**

Note 1 – The Capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net Excess as noted does not represent the excess recovery in each year.

In March 2017, the Financial Accounting Standards Board ("FASB") issued an Accounting Standard's Update (ASU 2017-07) that affects the accounting for pensions and OPEBs effective January 1, 2018.

As part of ASU 2017-07, Topic 715 – Compensation – Retirement Benefits of the US GAAP Accounting Standards Codification has been amended. The amendments allow only the service cost component of the net periodic pension cost and net periodic post-retirement benefit cost to be eligible for capitalization when applicable. For rate-setting purposes, Remotes accounts for its pension costs on a cash basis and therefore this amendment is not anticipated to affect the amounts included in this application. The changes to the accounting for OPEB, which Remotes accounts for on an accrual basis for rate-setting purposes, will affect this application.

The re-classification of these elements to OM&A would have an adverse impact on rates in a given year. As Remotes operates on a break-even basis, the net periodic post-retirement benefit cost other than service cost that would have been classified as capital prior to the issuance of ASU 2017-07 flows through the RRRP account effective January 1, 2018.

This page has been left blank intentionally.

APPENDIX 2-KA OPEBS COSTS

This exhibit has been filed separately in MS Excel format.

INCOME TAXES AND PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

1.0 INTRODUCTION

This Exhibit explains how Remotes calculates its income tax expenses for the purposes of rate recovery (Regulatory Taxes) and is organized as follows:

- Section 2.0 provides a general overview of Regulatory Taxes as a component of revenue requirement;
- Section 3.0 details the applicable income tax rates used in determining Regulatory Taxes;
- Section 4.0 explains the different bases for computation of accounting and taxable income;
- Section 5.0 addresses the general adjustments made in computing taxable income and categorizes the types of adjustments commonly observed;
- Section 6.0 discusses the tax treatment of regulatory assets and regulatory liabilities;
- Section 7.0 reconciles regulatory net income and taxable income; and
- Section 8.0 summarizes steps taken by Remotes to ensure data integrity.

Remotes also provides detailed calculations of its income tax expenses for the historical, bridge and test years, along with supporting schedules in Exhibit D, Tab 5, Schedule 1, Attachments 1 and 2, as well as a copy of its 2021 and 2021 tax returns in Exhibit D, Tab 5, Schedule 2.

2.0 REGULATORY TAXES – A COMPONENT OF REVENUE REQUIREMENT

Regulatory Taxes recoverable from ratepayers form part of the revenue requirement and are computed based on enacted tax legislation. Regulatory Taxes in a particular year represent the estimated current tax liability associated with regulatory net income before tax (NIBT) based on the applicable statutory tax rates for the year. Regulatory Taxes exclude future taxes arising from timing differences between when an amount is deductible or taxable for financial accounting and income tax purposes.

The regulatory tax calculations in this application only include items related to Remotes' regulated Distribution business, consistent with the stand-alone principle.[1]

3.0 REGULATORY TAXES – APPLICABLE INCOME TAX RATE (FEDERAL AND ONTARIO)

A combined income tax rate of 26.5% has been used for the 2023 test year, as set out in Table 1 below, based on a federal rate of 15%[2] and a provincial rate of 11.5%.[3] Due to the way rates are set for Remotes' customers, any variance between actual taxes payable and forecast taxes, as a result of changes in tax policy, tax legislation, income tax rates or capital cost allowance rates will be captured in the RRRP variance account, as described further in Exhibit H, Tab 2, Schedule 1.

Table 1 - Combined Income Tax Rates

	Historical				Bridge	Test
	2018	**2019**	**2020**	**2021-Forecast**	**2022**	**2023**
Federal Tax Rate (%)	15.00	15.00	15.00	15.00	15.00	15.00
Provincial Rate (%)	11.50	11.50	11.50	11.50	11.50	11.50
Total Statutory Tax Rate (%)	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**

4.0 CALCULATING TAXABLE INCOME

Regulatory Taxes are determined by applying the combined statutory tax rate to taxable income, which is derived from Remotes' Distribution regulated NIBT as shown on the utility's income statements for the year. Remotes' NIBT is prepared in accordance with U.S. Generally Accepted Accounting Principles (US GAAP), but taxable income is computed based on the applicable tax legislation (i.e., the ITA and Ontario Corporations Tax Act, 2007 (OCTA)), interpretations and CRA assessment practices. As such, adjustments are typically made to NIBT to arrive at taxable income.

[1] Section 2.6.2 of the Chapter 2 Distribution Filing Requirements dated April 18, 2022
[2] https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/corporation-tax-rates.html
[3] https://www.fin.gov.on.ca/en/tax/cit/index.html

Generally, to arrive at taxable income, NIBT is increased by amounts that are temporarily or permanently not deductible for tax purposes and reduced by amounts that are deductible for tax purposes, but which have not been deducted in computing NIBT.

5.0 TIMING/TEMPORARY DIFFERENCES

There are several adjustments made to NIBT to arrive at taxable income and most of these adjustments are made to account for timing differences. Adjustments for timing differences are temporary in nature and are necessary in circumstances where the treatment for financial accounting purposes differs from the treatment for tax purposes, but ultimately both treatments lead to the same result over time. The need for adjustments to NIBT due to timing differences can arise when:

1. Expenditures are both capitalized and depreciated over time under both financial accounting and tax requirements, but the depreciation rates and depreciation methodology differ;
2. Accrued costs are expensed for financial accounting purposes but tax deductions are allowed only when cash payments are made (i.e., Other Post-Employment Benefits (OPEB) and contingent liabilities); or
3. Costs are expensed for financial accounting purposes but are capitalized for tax purposes, or vice versa (i.e., capitalized overheads).

Common items that increase NIBT (i.e., they are added back to NIBT for tax purposes) include accounting depreciation, contingent liabilities, accounting losses, accrued expenditures related to OPEB and revenue that has been received but not recognized for accounting purposes.[4]

[4] For example, income received with respect to a deferral account that has been set-up on the balance sheet rather than shown as additional income on the income statement.

Common items that reduce NIBT (i.e., they are deducted from NIBT for tax purposes) include capital cost allowance, the deductible portion of capitalized overhead costs, accounting gains, OPEB payments, and expenses incurred for which a deferral and variance account has been set up on the balance sheet, rather than shown as deductions through the income statement.

Sections 5.1 to 5.3 below provide more detailed descriptions of the key timing differences and how they have historically impacted and will continue to impact Remotes' Regulatory Tax for the 2023 test year.

5.1 ACCOUNTING DEPRECIATION VS. TAX CAPITAL COST ALLOWANCE (CCA)

Accounting depreciation is based upon US GAAP while tax depreciation is based upon tax legislation resulting in differences in the calculation methods, asset classifications and the applicable depreciation rates used. Accounting depreciation is generally computed on a straight-line basis while tax depreciation, also known as capital cost allowance (CCA), is generally determined on a declining balance basis. Over the life of a particular asset, the tax CCA deductions will be higher in the earlier years and decline over time while the accounting depreciation will remain constant. This difference gives rise to one of the most significant timing differences, which must be reflected through adjustments to NIBT.

On June 21, 2019, Bill C-97 received Royal Assent and was enacted into federal legislation as the *Budget Implementation Act, 2019, No. 1* (BIA). The BIA temporarily enhanced CCA tax deductions pursuant to the Accelerated Investment Incentive (Accelerated CCA) and provided that certain capital property that was subject to the general CCA rules would be eligible for an enhanced first-year allowance. Property would be eligible if it was acquired after November 20, 2018, and became available for use before 2028. The enhancements provided a total of three times the normal tax CCA deductions for assets in-serviced up to December 31, 2023, and a total of two times the normal tax CCA deductions for assets in-serviced after December 31, 2023, through to December 31, 2027.

The detailed calculations of the CCA amounts are provided in Exhibit D, Tab 5, Schedule 1, Attachments 1 and 2 which incorporate the Accelerated CCA rules noted above. These CCA balances will be disposed of through the RRRP, as the OEB approved of Remotes' exemption request to use Account 1592.[5]

5.2 ACCRUAL VS CASH DISBURSEMENT

Net income determined under US GAAP generally allows a deduction for expenditures that have been incurred but not necessarily paid (i.e., on an accrual basis). For tax purposes, certain expenditures can be similarly deducted on an accrual basis, but some expenditures are explicitly limited to situations where there is an associated cash payment. An example that highlights this different treatment are OPEB costs, which are discussed in Sections 5.2.1 below.

5.2.1 OTHER POST EMPLOYMENT BENEFITS

Annual OPEB costs accrued for financial accounting purposes are comprised of amounts that are capitalized into fixed assets as well as amounts that are expensed as operations, maintenance and administration (OM&A) costs. However, for tax purposes, only the portion of annual OPEB costs that is actually paid for in the year can be deducted. OPEB payments are generally paid many years after they are accrued and, as a result, can give rise to significant timing differences between when the OPEB costs are accrued for financial accounting purposes and when the OPEB costs may be deducted for tax purposes.

Regulatory Taxes will generally be higher in years where OPEB expenditures are accrued without offsetting cash disbursements. Conversely, Regulatory Taxes will generally be lower in years where OPEB related cash disbursements are in excess of those accrued. The total available OPEB tax deduction over time does not change based on whether OPEB charges are recognized as OM&A costs or capitalized into fixed assets. However, revenue requirement is directly impacted by the method through which OPEB costs are recognized and recovered.

[5] See OEB's approval letter in Exhibit A, Tab 2, Schedule 1, Attachment 4

If OPEB amounts are capitalized into fixed assets, their recovery occurs over the life of the capital assets, as part of annual accounting depreciation. If OPEB amounts are expensed as OM&A costs, their recovery is immediate. Regulatory Taxes will be higher when OPEB amounts are expensed (as the immediate recovery of OM&A is higher) as compared to when capitalized. Even though the total tax deductions from annual OPEB costs remains unchanged, irrespective of the capital or expense treatment, Regulatory Taxes would be lower in years where more OPEB costs are capitalized and higher in years where more OPEB costs are expensed, all other things being equal.

5.3 CAPITALIZED OVERHEAD COSTS FOR ACCOUNTING VS. FOR TAX

Annually, for financial accounting purposes and in accordance with US GAAP, Remotes capitalizes a certain portion of overhead costs to fixed assets. That ability to capitalize overhead costs for financial accounting purposes is distinct from the ability to capitalize overhead costs for tax purposes. For the purposes of determining taxable income, capitalized overhead costs can be deducted immediately on the basis that they are not directly related to the acquisition or construction of capital assets and are considered to be recurring costs incurred as part of the day-to-day expenses of operating the business (Tax Deductible Capitalized Overheads). Tax Deductible Capitalized Overheads are based on tax legislation, jurisprudence, interpretation and principles accepted by the CRA and are not dependent on accounting treatments established under applicable accounting standards.

In light of this contrasting treatment, overhead costs being capitalized under US GAAP, but expensed for tax purposes, are another significant source of deductible timing differences, which have the effect of reducing Remotes' taxable income, the related Regulatory Taxes, and ultimately its revenue requirement.

6.0 TAX TREATMENT OF REGULATORY ASSETS AND LIABILITIES

Regulatory Assets and Regulatory Liabilities are typically recognized on utilities' balance sheets for foregone revenue or for expenses that have been incurred, for which recovery will be sought from ratepayers through future rates. Disposition of Regulatory Account balances is determined by the OEB.

Regulatory Assets and Regulatory Liabilities have not been included in computing Regulatory Taxes for purposes of calculating revenue requirement in accordance with Section 2.4.5.1 the Distribution Filing Requirements issued June 24, 2021.

7.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between Remotes’ regulatory NIBT and taxable income for the 2022 bridge and 2023 test year is provided in Exhibit D, Tab 5, Schedule 1, Attachment 2. This Schedule shows the income tax computation, which starts with the regulatory NIBT before adjusting for items such as depreciation and CCA. The NIL regulatory taxes amount for Remotes in 2023 reflects Remotes’ tax loss position from tax deductible timing differences for the year, and the calculation of CCA along with the reconciliation between accounting fixed asset additions as tax additions for the historical years are also provided in Exhibit D, Tab 5, Schedule 1, Attachment 1.

For ease of understanding the reconciliations, Remotes has placed these adjustments into the following two categories:

1. Recurring items included in revenue requirement such as accounting depreciation and CCA); and
2. Recurring items not included in revenue requirement such as CCA originated from the IPO Fair Market Value Revaluation (IPO FMV Revaluation).[6]

[6] IPO FMV Revaluation represents the additional tax benefits arising from the deemed disposition and reacquisition when Remotes exited the PILS regime and entered the Federal tax regime upon Hydro One Limited’s initial public offering (IPO) in 2015.

8.0 INTEGRITY CHECKS

Remotes has performed the integrity checks as described in PILS Workform in response to Section 2.6.2.1 of the Distribution Filing Requirements. Material exceptions are described below.

- The capital additions in the undepreciated capital cost (UCC) schedule do not agree with the rate base in the historical, bridge and test years in Exhibit D, Tab 5, Schedule 1, Attachment 2. This is primarily due to capitalized costs that are deductible (and not capitalized) for tax. Please see reconciliation of additions provided in Exhibit D, Tab 5, Schedule 1, Attachment 2.

Loss carry forwards on Schedule 4 of the 2020 Income Tax Return relates to (i) tax deductions from the additional CCA arising from the IPO FMV Revaluation represents and (ii) regulated tax losses from operations. The non-capital losses arise from the IPO FMV Revaluation represents benefits of the shareholders and are not considered in the calculation of regulatory taxes for the test period.

TAX 2018-2021 HISTORIC YEARS

This exhibit has been filed separately in MS Excel format.

TAX 2022-2023 BRIDGE AND TEST YEARS

This exhibit has been filed separately in MS Excel format.

HYDRO ONE REMOTE COMMUNITIES INC. INCOME TAX RETURNS

Attachment 1: Hydro One Remote Communities Inc. Income Tax Return 2020

Attachment 2: Hydro One Remote Communities Inc. Income Tax Return 2021

This page has been left blank intentionally.

200

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

055 **Do not use this area**

Filed: 2022-08-31
EB-2022-0041
Exhibit D-5-2
Attachment 1
Page 1 of 125

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 [redacted]

Corporation's name
002 Hydro One Remote Communities Inc.

Address of head office
Has this address changed since the last time we were notified? 010 Yes [ ] No [X]
If **yes**, complete lines 011 to 018.
011 483 BAY STREET 8TH FLOOR
012 SOUTH TOWER
City: 015 TORONTO
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal or ZIP code: 018 M5G 2P5

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 TAX DEPARTMENT
022 483 BAY STREET 7TH FLOOR
023 SOUTH TOWER
City: 025 TORONTO
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal or ZIP code: 028 M5G 2P5

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.
031 483 BAY STREET 7TH FLOOR
032 SOUTH TOWER
City: 035 TORONTO
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal or ZIP code: 038 M5G 2P5

040 **Type of corporation at the end of the tax year** (tick one)
- [ ] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [X] 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 (Year Month Day): 060 2020-01-01
Tax year-end (Year Month Day): 061 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.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170		29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		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	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	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 deduct ble 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	X	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 distr bution 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 elig ble 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	Electricity generation and distribution	285	100.000 %
286		287	%
288		289	%

		Yes	No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was elig ble 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	-642,612 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")				C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360	
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income elig ble for the small business deduction from Schedule 7 . . . . **400** ____ 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** ____ 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 ____ x **415** *** ____ D / 11,250 = ... ____ E

Passive income business limit reduction

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

Amount C ____ / 100,000 x Amount F ____ = ... ____ G

The greater of amount E and amount G **422** ____ 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 deduct ble 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 . . . . ________ 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) ________ K x 30 2 / 3 % = ________ 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 elig ble 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	10,763	
Tax instalments paid	840	15,827	
Total credits	890	26,590	26,590 B

Balance (amount A **minus** amount B) -26,590

Refund code 894 2 Refund 26,590

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 ______

Certification

I, 950 Tran (Last name) 951 Nancy (First name) 954 Vice President - Corporate Tax (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 2021-06-25 Date (yyyy/mm/dd) ______ Signature of the authorized signing officer of the corporation 956 (416) 345-6778 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . 957 Yes X 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

Schedule of Instalment Remittances

Name of corporation contact: Nancy Tran
Telephone number: (416) 345-6778

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	15,827
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	15,827 **A**
	Total instalments credited to the taxation year per T9	15,827 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2020-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	14,417,000	20,455,000
	Total tangible capital assets	2008	+	79,821,000	75,457,000
	Total accumulated amortization of tangible capital assets	2009	–	30,005,000	27,550,000
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	51,608,000	42,724,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	115,841,000	111,086,000
	Liabilities				
	Total current liabilities	3139	+	10,127,976	16,203,976
	Total long-term liabilities	3450	+	105,826,000	95,013,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	115,953,976	111,216,976
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	-112,976	-130,976
	Total liabilities and shareholder equity	3640	=	115,841,000	111,086,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-4,651,976	-4,651,976

***** Generic item

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
Hydro One Remote Communities Inc.	[redacted]	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	+	57,918,000	61,850,000
	Cost of sales	8518	–	30,945,000	31,714,000
	Gross profit/loss	8519	=	26,973,000	30,136,000
	Cost of sales	8518	+	30,945,000	31,714,000
	Total operating expenses	9367	+	27,062,676	30,235,877
	Total expenses (mandatory field)	9368	=	58,007,676	61,949,877
	Total revenue (mandatory field)	8299	+	58,004,200	61,947,762
	Total expenses (mandatory field)	9368	–	58,007,676	61,949,877
	Net non-farming income	9369	=	-3,476	-2,115
	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	=	-3,476	-2,115
	Total – other comprehensive income	9998	=	18,114	17,050
	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	–	-3,476	3,990
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+	18,114	17,050
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	18,114	10,945

Canada Revenue Agency | Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax Year End Year Month Day
Hydro One Remote Communities Inc.	[redacted]	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 [X] No [ ]

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 ☒

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 ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** Yes ☐ No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** Yes ☐ No ☒

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 ☒

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

General Index of Financial Information

Notes to the financial statements

Entity: Hydro One Remote Communities Inc. (the "Taxpayer")
Business Number: [redacted]
Taxation Year: December 31, 2020
Subject: 13(7.4) Election

The Taxpayer is electing under subsection 13(7.4) of the Income Tax Act with respect to amounts that would normally be included in income under paragraph 12(1)(x). The amount elected to reduce the cost of depreciable property instead of being included in income is $9,039,778.

1. DESCRIPTION OF THE BUSINESS

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the Business Corporations Act (Ontario) and is a wholly-owned subsidiary of Hydro One Inc. (Hydro One), which is wholly owned by Hydro One Limited. Hydro One Remote Communities generates and distributes electricity to customers in 21 off grid communities in northern Ontario and distributes to one community connected to the Province's electricity grid. The Company's business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On April 16, 2020, the OEB approved a 2% increase to Hydro One Remote Communities' 2019 base rates for new rates effective May 1, 2020, with a deferred implementation date of November 1, 2020 due to the COVID-19 pandemic (COVID-19 or the pandemic). On October 8, 2020, the OEB authorized Hydro One Remote Communities to implement a rate rider for the recovery of foregone revenues resulting from postponing rate implementation, effective November 1, 2020 until April 30, 2021.

New Service Territory

On December 6, 2018, the OEB amended Hydro One Remote Communities' electricity distribution licence to include the community of Pikangikum within its licensed service area, subject to certain conditions. On December 19, 2018, the community of Pikangikum was connected to a distribution system and the Company began providing service to the community. Effective August 14, 2019, all conditions were met and the Company is providing full service to the community.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. The Company uses a cost recovery model applied to achieve breakeven net income and the Financial Statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB.

Consolidated Financial Statements of Hydro One for the year ended December 31, 2020 have been prepared and are publicly available.

Hydro One Remote Communities performed an evaluation of subsequent events through to April 23, 2021, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, contingencies, and unbilled revenues. Actual results may differ significantly from these estimates.

Since late March 2020, the impact of COVID-19 has been reflected in the Company's financial statements. The Company has analyzed the impact of the pandemic on its estimates and assumptions that affect its financial results as at and for the year ended December 31, 2020 and has determined that there was no material impact.

As the duration of the pandemic remains uncertain, the Company continues to assess its impact to the Company's financial results and operations.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a subsequent event adjustment.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes. Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the RRRP variance account. The balance in the RRRP variance account is subject to future review and disposition by the OEB.

Revenue Recognition

Revenues attributable to the generation and delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, volume of electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes RRRP which is an amount relating to rate

General Index of Financial Information

Notes to the financial statements

protection for remote customers received from the Independent Electricity
System Operator (IESO) based on a standardized customer rate that is approved
by the OEB. Current legislation provides RRRP for prescribed classes of
rural,
residential and remote consumers by reducing the electricity rates that would
otherwise apply.
Revenues are recorded net of indirect taxes.
Accounts Receivable and Allowance for Doubtful Accounts
Billed accounts receivable are recorded at the invoiced amount, net of
allowance for doubtful accounts. Unbilled accounts receivable are recorded at
their estimated value, net of allowance for doubtful accounts. Overdue
amounts
related to regulated billings bear interest at OEB-approved rates. The
allowance for doubtful accounts reflects the Company's current lifetime
expected credit losses (CECL) for all accounts receivable balances. The
Company
estimates the CECL by applying internally developed loss rates to all
outstanding receivable balances by aging category. Loss rates applied to the
accounts receivable balances are based on historical overdue balances,
customer
payments and write-offs, which may be further supplemented from time to time
to reflect management's best estimate of the loss. Accounts receivable are
written-off against the allowance when they are deemed uncollectible. The
allowance for doubtful accounts is affected by changes in volume, prices and
economic conditions.
Long-term accounts receivable are recorded at their invoiced amount, net of
allowance for doubtful accounts and represent amounts due from specified
First
Nation communities. The component of long-term accounts receivable that is
energy-related does not bear interest. These amounts are reduced by
fixed-interval payments, received monthly throughout the term of the
agreement.
The CECL for this component is set at the inception of the balance and is
maintained until settlement of those amounts. The CECL for this component is
monitored and adjusted only if required with management discretion. The
component of long-term accounts receivable that is non-energy related is
reduced annually by a fixed incremental amount which is expensed through
performance of the associated contract. There is no provision associated with
these amounts.
Income Taxes
Income taxes are accounted for using the asset and liability method. Current
tax assets and liabilities are recognized based on the taxes payable or
refundable on the current and prior year's taxable income. Current and
deferred
income taxes are computed based on the tax rates and tax laws enacted as at
the balance sheet date. Tax benefits associated with income tax positions are
recorded only when the more-likely-than-not recognition threshold is
satisfied
and are measured at the largest amount of benefit that has a greater than 50%
likelihood of being realized upon settlement. Management evaluates each
position based solely on the technical merits and facts and circumstances of
the position, assuming the position will be examined by a taxing authority
having full knowledge of all relevant information. Significant management
judgment is required to determine recognition thresholds and the related
amount
of tax benefits to be recognized in the Financial Statements. Management

General Index of Financial Information

Notes to the financial statements

re-evaluates tax positions each period using new information about recognition
or measurement as it becomes available.

Deferred Income Taxes

Deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and
losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date.

Deferred income taxes associated with its regulated operations which are considered to be more-likely-than-not to be recoverable or refunded in the future regulated rates charged to customers are recognized as deferred income tax regulatory assets and liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that
the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month,
less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the balance sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion
of corporate costs such as finance, treasury, human resources, and information technology. Overhead costs, including corporate functions and field

services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts and capitalized project development costs associated with deferred capital projects.

Generation

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices, and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, tools, and other minor assets.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the statements of operations and comprehensive income (loss). Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction in Progress

Construction in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2013.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Generation	20	3% - 7%	4 %
Distribution	44	1% - 7%	2 %
Administration and service	38	3% - 20%	3 %

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, that are normally retired, is charged to accumulated depreciation with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Long-Lived Asset Impairment

General Index of Financial Information

Notes to the financial statements

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.
The carrying costs of most of Hydro One Remote Communities' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2020 and 2019, no asset impairment had been recorded.
Costs of Arranging Debt Financing
For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts net of related debt on the balance sheets.
Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within financing charges in the statements of operations and comprehensive income (loss). Transaction costs for items classified as held-for-trading are expensed immediately.
Comprehensive Income
Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.
The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents net income and OCI in a single continuous statement of operations and comprehensive income (loss).
Financial Assets and Liabilities
All financial assets and liabilities are classified into one of the following five categories (i) held-to-maturity, (ii) loans and receivables, (iii) held-for-trading, (iv) other liabilities, or (v) available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at its net realizable value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. The Company estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they

General Index of Financial Information

Notes to the financial statements

are deemed uncollectible.
The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain
of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in note 11 - Fair Value of Financial Instruments and Risk Management.
Derivative Instruments and Hedge Accounting
The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2020 and 2019. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

Employee Future Benefits
Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension,
post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.
Hydro One recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and post-employment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when
the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets.
If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.
Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of
labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.
Defined Benefit Pension
Hydro One has a contributory Pension Plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution pension plan and no pension benefit asset or liability is recorded.
Post-retirement and Post-employment Benefits
Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote

General Index of Financial Information

Notes to the financial statements

Communities. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in accumulated OCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment for the service cost component and to regulatory assets for all other components of the benefit costs, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they

General Index of Financial Information

Notes to the financial statements

occur.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators.

Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One Remote Communities records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One Remote Communities reviews its estimates of future

environmental expenditures annually or more frequently if there are indications
that circumstances have changed.

3. NEW ACCOUNTING PRONOUNCEMENTS
The following tables present Accounting Standard Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One Remote Communities:
Recently Adopted Accounting Guidance
Guidance Date issued Description Effective date Impact
ASU
2018-13 August 2018 Disclosure requirements on fair value measurements
in Accounting Standard Codification (ASC) 820 are modified to improve the effectiveness of disclosures in financial statement notes. January 1, 2020
No impact upon adoption
Recently Issued Accounting Guidance Not Yet Adopted
Guidance Date issued Description Effective date Anticipated impact
ASU
2018-14 August 2018 Disclosure requirements related to single-employer
defined benefit pension or other post-retirement
benefit plans are added, removed or clarified to
improve the effectiveness of disclosures in financial
statement notes. January 1, 2021 No impact upon adoption
ASU
2019-12 December 2019 The amendments simplify the accounting for income
taxes by removing certain exceptions to the general
principles and improving consistent application of
Topic 740 by clarifying and amending existing
guidance. January 1, 2021 No impact upon adoption
ASU 2020-10 October 2020 The amendments are intended to improve the
Codification by ensuring the guidance required for an entity to disclose
information in the notes of financial statements are codified in the disclosure
sections to reduce the likelihood of disclosure requirements being missed.
January 1, 2021 No impact upon adoption

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS
Year ended December 31 (thousands of dollars) 2020 2019
Depreciation of property, plant and equipment 2,834 2,867
Amortization of regulatory assets 870 3,851
Depreciation and amortization 3,704 6,718
Asset removal costs 361 511
4,065 7,229

5. FINANCING CHARGES
Year ended December 31 (thousands of dollars) 2020 2019
Interest on long-term debt 1,958 1,958
Amortization of hedging losses 18 17
Other 33 37
Interest capitalized on construction in progress (173) (124)
Interest income on inter-company demand facility (23)

General Index of Financial Information

Notes to the financial statements

(66)
1,813 1,822

6. INCOME TAXES

As a rate regulated utility company, the Company recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated business. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred income tax expense (recovery). The Company's tax expense or recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable or refunded in future rates charged to customers. Thus, the Company's income tax expense or recovery differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate.

The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (thousands of dollars)	2020	2019
Loss before income tax expense	(3)	(2)
Income tax expense at statutory rate of 26.5% (2019 - 26.5%)	(1)	(1)
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Non-capital losses	(225)	339
Depreciation and amortization in excess of capital cost allowance	271	1,037
Post-retirement and post-employment benefit expense in excess of cash payments	273	221
RRRP variance account	116	(411)
Environmental expenditures	(231)	(1,020)
Overheads capitalized for accounting but deducted for tax purposes	(152)	(139)
Pension contribution in excess of pension expense	(60)	(54)
Interest capitalized for accounting but deducted for tax purposes	(46)	(33)
Change in valuation allowance	-	6
Other	14	19
Net temporary differences	(40)	(35)
Prior year adjustments	8	4
Other permanent differences	30	36
Total income tax expense (recovery)	(3)	4

The major components of income tax expense (recovery) are as follows:

Year ended December 31 (thousands of dollars)	2020	2019
Current income tax expense (recovery)	(3)	4
Deferred income tax expense	-	-
Total income tax expense (recovery)	(3)	4

General Index of Financial Information

Notes to the financial statements

Effective income tax rate 100.0 % (200.0) %
The following table presents a reconciliation of net income (loss) to net income under the cost recovery model:

Year ended December 31 (thousands of dollars)	2020	2019
Net loss before income tax expense	(3)	(2)
Income tax recovery under cost-recovery model	(3)	(2)
Net income under cost-recovery model	-	-
Income tax expense	-	6
Net loss	-	(6)

Deferred Income Tax Assets and Liabilities
Deferred income tax assets and liabilities reflect the future tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and liabilities attributable to the Company's regulated business are recognized with a corresponding offset in deferred income tax regulatory assets and liabilities to reflect the anticipated recovery or repayment of these balances
in the future electricity rates. At December 31, 2020 and 2019, deferred income tax assets and liabilities consisted of the following:

As at December 31 (thousands of dollars)	2020	2019
Deferred income tax assets (liabilities)		
Environmental expenditures	15,640	12,293
Depreciation and amortization in excess of capital cost allowance	3,448	4,225
Post-retirement and post-employment benefits expense in excess of cash payments	6,623	6,249
Regulatory amounts not recognized for tax	(17,895)	(14,802)
Other	2,370	2,320
	10,186	10,285
Less: valuation allowance	(5,693)	(5,702)
Net deferred income tax assets	4,493	4,583

During 2020 and 2019, there was no change in the rate applicable to deferred tax assets and liabilities. The valuation allowance for deferred tax assets as
at December 31, 2020 was $5,693 thousand (2019 - $5,702 thousand). The valuation allowance primarily relates to temporary differences for non-depreciable assets. As at December 31, 2020, the Company had non-capital losses of $9,035 thousand, which will begin to expire in 2036.

7. ACCOUNTS RECEIVABLE

As at December 31, 2020 (thousands of dollars)	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable - billed	6,179	49	6,228
Accounts receivable - unbilled	2,920	-	2,920
Accounts receivable, gross	9,099	49	9,148
Allowance for doubtful accounts	(324)	-	(324)
Accounts receivable, net	8,775	49	8,824

As at December 31, 2019 (thousands of dollars)	Current accounts receivable	Long-term accounts receivable	Total
Accounts receivable - billed	4,026	122	4,148
Accounts receivable - unbilled	3,531	-	3,531
Accounts receivable, gross	7,557	122	7,679
Allowance for doubtful accounts	(119)	-	(119)
Accounts receivable, net	7,438	122	7,560

General Index of Financial Information

Notes to the financial statements

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2020 and 2019:

Year ended December 31 (thousands of dollars)	2020	2019
Allowance for doubtful accounts - beginning	(119)	(59)
Write-offs	98	72
Adjustments to allowance for doubtful accounts	(303)	(132)
Allowance for doubtful accounts - ending	(324)	(119)

8. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2020 (thousands of dollars)	Property, Plant and Equipment 1	Accumulated Depreciation	Construction in Progress	Total
Generation	51,077	23,445	2,842	30,474
Distribution	12,315	2,908	813	10,220
Administration and service	12,743	3,652	31	9,122
	76,135	30,005	3,686	49,816

1 Includes future use assets totalling $4,534 thousand.

As at December 31, 2019 (thousands of dollars)	Property, Plant and Equipment 1	Accumulated Depreciation	Construction in Progress	Total
Generation	48,233	21,406	2,177	29,004
Distribution	12,085	2,654	297	9,728
Administration and service	12,645	3,490	20	9,175
	72,963	27,550	2,494	47,907

1 Includes future use assets totalling $3,541 thousand.

Financing charges capitalized on property, plant and equipment under construction were $173 thousand in 2020 (2019 - $124 thousand).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

As at December 31 (thousands of dollars)	2020	2019
Regulatory assets:		
Environmental	43,378	34,095
RRRP variance account	5,598	6,089
Post-retirement and post-employment benefits	569	870
Stock-based compensation	467	462
COVID-19 emergency deferral	120	-
Total regulatory assets	50,132	41,516
Less: current portion	(3,087)	(3,518)
	47,045	37,998
Regulatory liabilities:		
Deferred income tax regulatory liability	4,493	4,583
Tax rule changes variance	-	54
Total regulatory liabilities	4,493	4,637
Less: current portion	-	-
	4,493	4,637

Environmental

The Company records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized

because management considers it to be probable environmental expenditures will
be recovered in the future through the rate-setting process. The Company has recorded an equivalent amount as a regulatory asset. In 2020, the environmental
regulatory asset increased by $10,153 thousand (2019 - $2,802 thousand) to reflect related changes in the Company's environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and
the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2020 OM&A expenses would have been higher by $10,153 thousand (2019 - $2,802 thousand), and 2020 amortization expense would have been lower by $870 thousand (2019 - $3,851 thousand).

RRRP Variance Account

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2020, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery
model, in excess of cumulative RRRP amounts received. In 2020, RRRP amounts received were higher (2019 - lower) than amounts required to achieve breakeven
net income, and as such, the regulatory asset was reduced by $491 thousand (2019 -increased by $4,120 thousand). In the absence of rate-regulated accounting, 2020 revenue would have been higher by $491 thousand (2019 - lower
by $4,120 thousand).

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the balance sheets with an incremental offset to the associated regulatory assets.

A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In
the absence of rate-regulated accounting, 2020 OCI would have been higher by $301 thousand (2019 - lower by $2,264 thousand).

Stock-Based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2020 operation, maintenance and administration expenses would have been higher by $3 thousand (2019 - $1 thousand). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said
labour costs.

COVID-19 Emergency Deferral

General Index of Financial Information

Notes to the financial statements

The COVID-19 emergency deferral account comprises of five sub-accounts established to track incremental costs and lost revenues related to the COVID-19 pandemic: (i) Billing and System Changes as a Result of the Emergency
Order Regarding Time-of-Use Pricing, (ii) Lost Revenues Arising from the COVID-19 Emergency, (iii) Other Incremental Costs, (iv) Foregone Revenues from
Postponing Rate Implementation, and (v) Bad Debt.
As at December 31, 2020, the Company has recorded a regulatory asset for 2020 foregone revenues that are being collected from ratepayers over the period from November 1, 2020 to April 30, 2021. The Company continues to track certain
incremental costs and lost revenues that have arisen due to the COVID-19 pandemic in the other tracking accounts noted above, however, the Company has assessed that these amounts are not probable for future recovery in rates and no amounts related to the COVID-19 pandemic have been recognized as regulatory
assets.
Deferred Income Tax Regulatory Liability
Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company
has recognized a regulatory liability that corresponds to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts
established for taxes to be recovered through future rates. As a result, the 2020 income tax expense would have been higher by approximately $40 thousand (2019 - $80 thousand).

10. LONG-TERM DEBT
Long-term debt represents inter-company debt issued to Hydro One. The following table presents the Company's outstanding long-term debt at December 31, 2020 and 2019:

As at December 31 (thousands of dollars)	2020	2019
3.02% note due 2026	10,000	10,000
5.38% note due 2036	23,000	23,000
4.19% note due 2044	10,000	10,000
	43,000	43,000
Less: Deferred debt issuance costs	(150)	(158)
Less: Net unamortized debt premiums	(33)	(34)
Long-term debt	42,817	42,808

The Company did not issue or repay any long-term debt in 2020 and 2019.
Principal and Interest Payments
At December 31, 2020, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

Years	Long-Term Debt Principal Repayments (thousands of dollars)	Interest Payments (thousands of dollars)	Weighted-Average Interest Rate (%)
2021	-	1,958	-
2022	-	1,958	-
2023	-	1,958	-

2024	-	1,958	-
2025	-	1,958	-
	-	9,790	-
2026-2030	10,000	8,433	3.0
2031+	33,000	12,464	5.0
	43,000	30,687	4.6

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One Remote Communities classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Remote Communities has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2020 and 2019, the Company's carrying amounts of inter-company demand facility, accounts receivable, and accounts payable are representative of fair value due to the short-term nature of these instruments.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2020 and 2019 is as follows:

As at December 31, 2020 (thousands of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt	42,817	55,701	-	55,701	

General Index of Financial Information

Notes to the financial statements

-
As at December 31, 2019 (thousands of dollars) Carrying
Value Fair
Value
Level 1
Level 2
Level 3
Liabilities:
Long-term debt 42,808 51,407 - 51,407
-

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.
There were no transfers between any of the fair value levels during the years ended December 31, 2020 or 2019.

Risk Management
Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.
Market Risk
Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.
Credit Risk
Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2020 and 2019, there were
no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One Remote Communities did not earn a material amount of revenue from any single customer. At December 31, 2020 and 2019, there was no material accounts receivable balance due from any single customer.
At December 31, 2020, the Company's allowance for doubtful accounts was $324 thousand (2019 - $119 thousand). The allowance for doubtful accounts reflects the Company's CECL for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. At December 31,
2020, approximately 28% (2019 - 23%) of the Company's net accounts receivable were outstanding for more than 60 days. The Company's credit risk for accounts receivable is limited to the carrying amounts on its balance sheets.
Liquidity Risk
Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities meets its short-term
liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company are expected to be sufficient to fund normal operating requirements.

12. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS
Hydro One has a Pension Plan, a DC Plan, a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.
DC Plan

General Index of Financial Information

Notes to the financial statements

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplemental DC Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the Income Tax Act (Canada) in the form of credits to a notional account. Company contributions to the DC Plan for the year ended December 31, 2020 were $10 thousand (2019 - $10 thousand).

Pension Plan and Supplemental Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The next actuarial valuation will be performed no later than effective December 31, 2021. Total Hydro One annual cash Pension Plan employer contributions for the Company in 2020 were $711 thousand (2019 - $693 thousand). The estimated Hydro One annual Pension Plan employer contributions allocated to the Company for the years 2021, 2022, 2023, 2024, 2025, 2026 and 2027 are approximately $692 thousand, $1,053 thousand, $1,110 thousand, $1,156 thousand, $1,163 thousand, $1,190 thousand and $1,240 thousand respectively.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the Income Tax Act (Canada).

At December 31, 2020, the present value of Hydro One's projected pension benefit obligation was estimated to be $9,763 million (2019 - $8,973 million).

The fair value of pension plan assets available for these benefits was $8,103 million (2019 - $7,848 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2020, Hydro One Remote Communities charged $1,098 thousand (2019 - $1,012 thousand) of post-retirement and post-employment benefit costs to operation, maintenances and administration expenses, and capitalized $512 thousand (2019 - $431 thousand) as part of the

General Index of Financial Information

Notes to the financial statements

cost of property, plant and equipment. Benefits paid by the Company in 2020 were $272 thousand (2019 - $183 thousand). In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $301 thousand (2019 - increase of $2,264 thousand) was recorded on the Company's balance sheet to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the balance sheets within the following line items:

As at December 31 (thousands of dollars)	2020	2019
Accrued liabilities	473	467
Post-retirement and post-employment benefit liability	17,898	16,866
	18,371	17,333

13. ENVIRONMENTAL LIABILITIES

The following table shows the movements in environmental liabilities for the years ended December 31, 2020 and 2019:

Year ended December 31 (thousands of dollars)	2020	2019
Environmental liabilities - beginning	34,095	35,144
Expenditures	(870)	(3,851)
Revaluation adjustment	10,153	2,802
Environmental liabilities - ending	43,378	34,095
Less: current portion	(2,863)	(3,414)
	40,515	30,681

The following table shows the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the balance sheets after factoring in the discount rate:

As at December 31 (thousands of dollars)	2020	2019
Undiscounted environmental liabilities	43,378	34,095
Less: discounting environmental liabilities to present value	-	-
Discounted environmental liabilities	43,378	34,095

At December 31, 2020, the estimated future environmental expenditures were as follows:

(thousands of dollars)	
2021	2,863
2022	1,785
2023	1,183
2024	2,315
2025	2,315
Thereafter	32,917
	43,378

The Company records a liability for the estimated future expenditures for LAR when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of

completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs, which is its undiscounted amount, required to meet existing legislation
or regulations.

As at December 31, 2020, the Company's best estimate of the total estimated future expenditures to complete its LAR program was $43,378 thousand (2019 - $34,095 thousand). These expenditures are expected to be incurred over the period from 2021 to 2057. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2020 to increase
the LAR environmental liability by $10,153 thousand (2019 - $2,802 thousand).

14. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2020, the Company had 267 common shares issued and outstanding (2019 - 267).

Dividends

The Company does not pay dividends under its breakeven business model.

15. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Remote Communities, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant
Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees
of Hydro One Remote Communities.

General Index of Financial Information

Notes to the financial statements

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore, the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Remote Communities of $1,091 thousand was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2020, 5,387 common shares of Hydro One Limited were issued under the Share Grant Plans (2019 - 5,072) to eligible employees of Hydro One Remote Communities. Total share based compensation recognized by Hydro One Remote Communities during 2020 was $115 thousand (2019 - $105 thousand) and was recorded as a regulatory asset.

A summary of Hydro One Remote Communities' share grant activity under the Share Grant Plans during years ended December 31, 2020 and 2019 is presented below:

Year ended December 31, 2020	Share Grants (Number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	38,328	$20.50
Vested and issued1	(5,387)	-
Transfers2	2,865	-
Forfeited	(822)	$20.50
Share grants outstanding - ending	34,984	$20.50

1 In 2020, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

2 Transfers relate to PWU employees transferred from Hydro One Networks to Hydro One Remote Communities during 2020. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.

Year ended December 31, 2019	Share Grants (Number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	43,464	$20.50
Vested and issued1	(5,072)	-
Forfeited	(64)	$20.50
Share grants outstanding - ending	38,328	$20.50

1 In 2019, Hydro One Limited issued from treasury common shares to eligible

Hydro One Remote Communities employees in accordance with provisions of the Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2020, Company contributions made under the ESOP were $22 thousand (2019 - $19 thousand).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

During 2020 and 2019, the activity of PSU and RSU awards granted by Hydro One Limited that related to Hydro One Remote Communities were as follows:

	PSUs		RSUs	
Year ended December 31 (number of units)	2020	2019	2020	2019
Units outstanding - beginning	6,065	10,334	2,377	6,205
Vested and issued1	(2,711)	(1,688)	(12)	(1,971)
Forfeited	(70)	(59)	(46)	(53)
Other2	-	(2,522)	-	(1,804)
Units outstanding - ending	3,284	6,065	2,319	2,377

1 In 2020, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions

General Index of Financial Information

Notes to the financial statements

of the LTIP. In accordance with the inter-company agreement between Hydro One
and Hydro One Limited, Hydro One Remote Communities made payments to Hydro
One
for the common shares issued.
2 In 2018, the Province of Ontario issued the Hydro One Accountability Act
(Accountability Act) that directed compensation related changes for Hydro One
Limited as well as amended the Ontario Energy Board Act (OEB Act) to restrict
the recovery of any executive compensation in the rate approvals of any Hydro
One Limited subsidiaries. As a result, to comply with the Accountability Act
and the OEB Act, in 2019 Hydro One Limited removed all executive-related
compensation from the labour costs of its regulates subsidiaries. During the
year ended December 31, 2020, no executive-related stock-based compensation
was
allocated to the regulated businesses of Hydro One Remote Communities.
No awards were granted in 2020 or 2019. The compensation expense related to
the PSU and RSU awards recognized by the Company during 2020 was $100
thousand
(2019 - $162 thousand).

16. RELATED PARTY TRANSACTIONS
Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned
by Hydro One Limited. The Province is a shareholder of Hydro One Limited with
approximately 47.3% ownership at December 31, 2020. The IESO is a related
party to Hydro One Remote Communities because it is controlled or
significantly
influenced by the Ministry of Energy.
Year ended December 31 (thousands of dollars)

Related Party	Transaction	2020	2019
IESO	Supply of electricity to remote northern communities - amounts received1	35,223	35,223
	Amounts related to electricity rebates	7,735	3,312
Hydro One Networks Inc.	Revenues related to the provision of services2	160	293
	Cost of power	1,665	1,451
	Costs expensed related to purchase of services2	3,158	3,332
Hydro One Inc.	Interest income on inter-company demand facility	23	66
	Interest expense on long-term debt	1,958	1,958
	Costs expensed related to purchase of services2	23	34
	Stock-based compensation costs	215	267

1 Consistent with the break even business model, the Company recognized
$34,732 thousand as RRRP revenue in 2019 (2019 - $39,736), with the
difference
recorded in the regulatory asset RRRP variance account.
2 The Company has entered into various agreements with Hydro One and its other
subsidiaries related to the provision of corporate functions and services,
such as legal, financial and human resources services, and operational
services, such as environmental, forestry, and line services.
Transactions with related parties are based on the requirements of the OEB's
Affiliate Relationships Code.
The amounts due to and from related parties are as follows:
As at December 31 (thousands of dollars)

General Index of Financial Information

Notes to the financial statements

2020 2019
Inter-company demand facility
(42) 6,441
Accounts receivable 767 668
Accrued interest
280 280
Long-term debt 42,967 42,966

17. STATEMENTS OF CASH FLOWS
The changes in non-cash balances related to operations consist of the following:
Year ended December 31 (thousands of dollars) 2020 2019
Accounts receivable (1,337) 148
Fuel, materials and supplies
498 100
Income taxes receivable
5 468
Long-term accounts receivable 73 54
Accounts payable (6,120) 4,614
Accrued liabilities (184) 1,906
Long-term accounts payable 82 -
Post-retirement and post-employment benefit liability 1,333
1,182
(5,650) 8,472
Supplementary Information
Year ended December 31 (thousands of dollars) 2020 2019
Net interest paid 1,958 1,958
As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid are fully recovered.

18. CONTINGENCIES
Legal Proceedings
Hydro One Remote Communities is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect
on the Company's financial position, results of operations or cash flows.
Hydro One Remote Communities is a defendant in a lawsuit in which the plaintiff Wilderness North Air is seeking $16 million in damages related to allegations of breach of contract following a competitive request for proposals
for the supply of diesel fuel. Hydro One Remote Communities is defending itself in the claim and has determined there is a reasonable possibility of liability to the Company, and if liability is found, the estimated range of losses is between $50 thousand to $400 thousand.
Transfer of Assets
The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on
Reserves (as defined in the Indian Act (Canada)). Currently, the Ontario Electricity Financial Corporation (OEFC) holds these assets. Under the terms of
the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these
assets to itself. Hydro One cannot predict the aggregate amount that it may

General Index of Financial Information

Notes to the financial statements

have to pay, either on an annual or one-time basis, to obtain the required consents. In 2020, Hydro One paid approximately $2 million (2019 - $2 million)
in respect of consents obtained. If Hydro One or the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One cannot reach a satisfactory settlement,
it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on Hydro One's and the Company's results of operations if Hydro One is not able to recover them in future rate orders.

19. COMMITMENTS

Operating Agreement

Hydro One Remote Communities is committed to an operating agreement related to a hydro facility owned by the Company to pay annual performance payments for a period of 10 years. The operating agreement expires in 2022. During the year ended December 31, 2020, the Company made payments totalling $150 thousand (2019 - $150 thousand). The following table presents a summary of Hydro One Remote Communities' commitments under this agreement.

December 31, 2020 (thousands of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Operating agreement	150	150	-	-	-	-

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2020-12-31

Assets – lines 1000 to 2599

1062	8,775,000	1066	20,000	1122	2,535,000
1480	3,087,000	1599	14,417,000	1740	63,392,000
1741	-26,353,000	1900	12,743,000	1901	-3,652,000
1920	3,686,000	2008	79,821,000	2009	-30,005,000
2420	47,115,000	2421	4,493,000	2589	51,608,000
2599	115,841,000				

Liabilities – lines 2600 to 3499

2620	9,805,976	2629	280,000	2860	42,000
3139	10,127,976	3140	42,817,000	3320	18,001,000
3321	45,008,000	3450	105,826,000	3499	115,953,976

Shareholder equity – lines 3500 to 3640

3500	5,000,000	3580	-461,000	3600	-4,651,976
3620	-112,976	3640	115,841,000		

Retained earnings – lines 3660 to 3849

3660	-4,651,976	3849	-4,651,976

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2020-12-31

Description

Sequence number **0003** 01

Other comprehensive income – lines 7000 to 7020

7008	18,114

Revenue – lines 8000 to 8299

8000	57,918,000	8089	57,918,000	8210	86,200
8299	58,004,200				

Cost of sales – lines 8300 to 8519

8408	29,166,000	8450	1,779,000	8518	30,945,000
8519	26,973,000				

Operating expenses – lines 8520 to 9369

8523	67,828	8623	492,190	8670	4,064,835
8714	1,813,000	9270	20,624,823	9367	27,062,676
9368	58,007,676	9369	-3,476		

Extraordinary items and taxes – lines 9970 to 9999

9970	-3,476	9990	-3,476	9998	18,114
9999	18,114				

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
Hydro One Remote Communities Inc.	[redacted]	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			18,114	A
Add:				
Provision for income taxes – current	101	-3,476		
Amortization of tangible assets	104	4,064,835		
Non-deductible meals and entertainment expenses	121	33,914		
Other reserves on lines 270 and 275 from Schedule 13	125	92,880		
Reserves from financial statements – balance at the end of the year	126	12,257,120		
Subtotal of additions		16,445,273 ▶	16,445,273	
Other additions:				
Financing fees deducted in books	216	8,008		

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Non-deductible LTIP and share grants	136,915
2	2019 provision to return for Ont ITC in OMA	8,809
	Total of column 2	145,724 ▶

Total of column 2	296	145,724		
Subtotal of other additions	199	153,732 ▶	153,732	D
Total additions	500	16,599,005 ▶	16,599,005	
Amount A **plus** line 500			16,617,119	B
Deduct:				
Gain on disposal of assets per financial statements	401	86,200		
Capital cost allowance from Schedule 8	403	4,311,721		
Other reserves on line 280 from Schedule 13	413	91,559		
Reserves from financial statements – balance at the beginning of the year	414	10,526,587		
Contributions to deferred income plans from Schedule 15	417	229,495		
Subtotal of deductions		15,245,562 ▶	15,245,562	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Deduction under 20(1)(e) ITA	8,323
2	Deductible removable costs	75,620
3	Deduction for capitalized amounts - see attached	746,377
4	OPEB capitalized	307,467
5	Environmental payments	870,252
6	2020 Ontario co-op and apprentice credits overaccual	6,130
	Total of column 2	2,014,169 ▶

Total of column 2	396	2,014,169

Subtotal of other deductions	499	2,014,169 ▶	2,014,169	E
Total deductions	510	17,259,731 ▶	17,259,731	
Net income (loss) for income tax purposes (amount B **minus** line 510)			-642,612	C

Enter amount C on line 300 of the T2 return.

T2 SCH 1 E (19)

Canadä

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Description	Operator (Note)	Amount	
Capitalized interest		172,814	00
Capitalized overhead	+	573,563	00
	+		
	+		
	Total	746,377	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 295 – Amount

Title Line 295 – Amount

Description	Operator (Note)	Amount
Non-deductible LTIP		61,276 00
Non-deductible Union share grants	+	75,639 00
	+	
	Total	136,915 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.

Deduction summary as per paragraph 20(1)(e) of the ITA

Federal

Deduction summary as per paragraph 20(1)(e) of the ITA

Description		Date of expense	A Expense amount	B Amounts deduct ble in the preceding taxation years	E Annual deduction (This amount is posted to one of the lines 395 of Schedule 1)	F Balance at the end of the year
1.	Prospectus costs - 2016	2016-12-31	1,738	1,393	345	
2.	Underwriting fees - 2016	2016-12-31	40,000	32,022	7,978	
		Totals	41,738	33,415	8,323	

Deduction as per paragraph 20(1)(e) of the ITA

This workchart allows you to determine the tax deduction as per paragraph 20(1)(e) of the Income Tax Act (ITA). It relates to the expenses of issuing or selling shares, units or interests and expenses of borrowing money.

Ensure that any of these expenses deducted in the financial statements have been added back on line 216, "Financing fees deducted in books," and/or on line 235, "Share issue expense" to Schedule 1, if applicable.

* If the check box was selected, the annual deduction will be equal to the amount in column C.

1 Description: Prospectus costs - 2016

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 366 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2016-12-31	1,738	1,393	345	349	345	

2 Description: Underwriting fees - 2016

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 366 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2016-12-31	40,000	32,022	7,978	8,022	7,978	

Canada Revenue Agency / Agence du revenu du Canada

Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2020-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the Income Tax Act, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deduct ble in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deduct ble in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the T2 Corporation – Income Tax Guide.
- File this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the Income Tax Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			-642,612 1A
Net capital losses deducted in the year (enter as a positive amount)		1B	
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)		1C	
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)		1D	
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		1E	
Employer deduction in respect of non-qualified securities – Paragraph 110(1)(e)		1F	
Subtotal (total of amounts 1B to 1F)		▶	1G
Subtotal (amount 1A **minus** amount 1G; if positive, enter "0"			-642,612 1H
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions			1I
Subtotal (amount 1H **minus** amount 1I)			-642,612 1J
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)			1K
Current-year non-capital loss (amount 1J **plus** amount 1K; if positive, enter "0") If amount 1L is negative, enter it on line 110 as a positive.			-642,612 1L

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		8,333,589 1M	
Non-capital loss expired **(note 1)**	100		
Non-capital losses at the beginning of the tax year (amount 1M **minus** line 100)	102	8,333,589 ▶	8,333,589
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary **(note 2)** corporation	105		
Current-year non-capital loss (from amount 1L)	110	642,612	
Subtotal (line 105 **plus** line 110)		642,612 ▶	642,612 1N
Subtotal (line 102 **plus** amount 1N)			8,976,201 1O

Note 1: A non-capital loss expires after **20** tax years and an allowable business investment loss becomes a net capital loss after **10** tax years.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Other adjustments (includes adjustments for an acquisition of control)	150			
Section 80 – Adjustments for forgiven amounts	140			
Subsection 111(10) – Adjustments for fuel tax rebate				
Non-capital losses of previous tax years applied in the current tax year Enter line 130 on line 331 of the T2 Return.	130			
Current and previous years non-capital losses applied against current-year taxable dividends subject to Part IV tax **(note 3)**	135			
Subtotal (total of lines 150, 140, 130 and 135)				1P
Non-capital losses before any request for a carryback (amount 1O **minus** amount 1P)			8,976,201	1Q

Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901			
Second previous tax year to reduce taxable income	902			
Third previous tax year to reduce taxable income	903			
First previous tax year to reduce taxable dividends subject to Part IV tax	911			
Second previous tax year to reduce taxable dividends subject to Part IV tax	912			
Third previous tax year to reduce taxable dividends subject to Part IV tax	913			
Total of requests to carry back non-capital losses to previous tax years (total of lines 901 to 913)				1R
Closing balance of non-capital losses to be carried forward to future tax years (amount 1Q **minus** amount 1R)	180		8,976,201	

Note 3: Line 135 is the total of lines 330 and 335 from Schedule 3, Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200			
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205			
Subtotal (line 200 **plus** line 205)				2A
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Subtotal (line 250 **plus** line 240)				2B
Subtotal (amount 2A **minus** amount 2B)				2C
Current-year capital loss (from the calculation on Schedule 6, Summary of Dispositions of Capital Property)	210			
Unused non-capital losses from the 11th previous tax year **(note 4)**			2D	
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year **(note 5)**			2E	
Enter amount 2D or 2E, whichever is less	215			
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220			
Subtotal (amount 2C **plus** line 210 **plus** line 220)				2F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220.

Note 4: Determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not deducted in the previous 11 years.

Note 5: Enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on amount 2E.

Part 2 – Capital losses (continued)

Capital losses from previous tax years applied against the current-year net capital gain **(note 6)** . . . . . 225 ____

Capital losses before any request for a carryback (amount 2F **minus** line 225) ____ 2G

Request to carry back capital loss to (note 7):

	Capital gain (100%)		Amount carried back (100%)	
First previous tax year		951		
Second previous tax year		952		
Third previous tax year		953		
Subtotal (total of lines 951 to 953)				2H

Closing balance of capital losses to be carried forward to future tax years (amount 2G **minus** amount 2H) **(note 8)** 280 ____

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current tax year, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **divide** this amount by 2. The result represents the 50% inclusion rate.

Note 8: Capital losses can be carried forward indefinitely.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

	Line	Amount		Total
Farm losses at the end of the previous tax year			3A	
Farm loss expired **(note 9)**	300			
Farm losses at the beginning of the tax year (amount 3A **minus** line 300)	302			
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305			
Current-year farm loss (amount 1K in Part 1)	310			
Subtotal (line 305 **plus** line 310)				3B
Subtotal (line 302 **plus** amount 3B)				3C
Other adjustments (includes adjustments for an acquisition of control)	350			
Section 80 – Adjustments for forgiven amounts	340			
Farm losses of previous tax years applied in the current tax year Enter line 330 on line 334 of the T2 Return.	330			
Current and previous years farm losses applied against current-year taxable dividends subject to Part IV tax **(note 10)**	335			
Subtotal (total of lines 350, 340, 330 and 335)				3D
Farm losses before any request for a carryback (amount 3C **minus** amount 3D)				3E

Request to carry back farm loss to:

	Line	Amount		Total
First previous tax year to reduce taxable income	921			
Second previous tax year to reduce taxable income	922			
Third previous tax year to reduce taxable income	923			
First previous tax year to reduce taxable dividends subject to Part IV tax	931			
Second previous tax year to reduce taxable dividends subject to Part IV tax	932			
Third previous tax year to reduce taxable dividends subject to Part IV tax	933			
Subtotal (total of lines 921 to 933)				3F
Closing balance of farm losses to be carried forward to future tax years (amount 3E **minus** amount 3F)	380			

Note 9: A farm loss expires after **20** tax years.

Note 10: Line 335 is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			485	
(line 485 ______ – $2,500) **divided** by 2		4A		
Amount 4A or $ 15,000 , whichever is less				4B
		2,500		4C
Subtotal (amount 4B **plus** amount 4C)		2,500	2,500	4D
Current-year restricted farm loss (line 485 **minus** amount 4D)				4E

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year				4F
Restricted farm loss expired **(note 11)**	400			
Restricted farm losses at the beginning of the tax year (amount 4F **minus** line 400)	402			
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	405			
Current-year restricted farm loss (from amount 4E)	410			
Enter line 410 on line 233 of Schedule 1, Net Income (Loss) for Income Tax Purposes.				
Subtotal (line 405 **plus** line 410)				4G
Subtotal (line 402 **plus** amount 4G)				4H
Restricted farm losses from previous tax years applied against current farming income	430			
Enter line 430 on line 333 of the T2 return.				
Section 80 – Adjustments for forgiven amounts	440			
Other adjustments	450			
Subtotal (total of lines 430 to 450)				4I
Restricted farm losses before any request for a carryback (amount 4H **minus** amount 4I)				4J

Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	941			
Second previous tax year to reduce farming income	942			
Third previous tax year to reduce farming income	943			
Subtotal (total of lines 941 to 943)				4K
Closing balance of restricted farm losses to be carried forward to future tax years (amount 4J **minus** amount 4K)	480			

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 11: A restricted farm loss expires after **20** tax years.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			5A	
Listed personal property loss expired **(note 12)**	500			
Listed personal property losses at the beginning of the tax year (amount 5A **minus** line 500)	502		▶	
Current-year listed personal property loss (from Schedule 6)			510	
Subtotal (line 502 **plus** line 510)				5B
Listed personal property losses from previous tax years applied against listed personal property gains	530			
Enter line 530 on line 655 of Schedule 6.				
Other adjustments	550			
Subtotal (line 530 **plus** line 550)			▶	5C
Listed personal property losses remaining before any request for a carryback (amount 5B **minus** amount 5C)				5D

Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961			
Second previous tax year to reduce listed personal property gains	962			
Third previous tax year to reduce listed personal property gains	963			
Subtotal (total of lines 961 to 963)			▶	5E
Closing balance of listed personal property losses to be carried forward to future tax years (amount 5D **minus** amount 5E)			580	

Note 12: A listed personal property loss expires after **7** tax years.

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number	Tax year ending yyyy/mm/dd	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6)
	600	602	604	606	608		620
1.							

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number	Tax year ending yyyy/mm/dd	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
	630	632	634	636	638		650
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary	Current-year limited partnership losses (from line 620)	Limited partnership losses applied in the current year (must be equal to or less than line 650)	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5)
	660	662	664	670	675	680
1.						

Total (enter this amount on line 335 of the T2 return)

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . 190 Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A	642,612			N/A		642,612
1st preceding taxation year 2019-12-31	2,789,810	N/A		N/A			2,789,810
2nd preceding taxation year 2018-12-31	5,039,814	N/A		N/A			5,039,814
3rd preceding taxation year 2017-12-31	306,376	N/A		N/A			306,376
4th preceding taxation year 2016-12-31	197,589	N/A		N/A			197,589
5th preceding taxation year 2015-12-31		N/A		N/A			
6th preceding taxation year 2015-11-04		N/A		N/A			
7th preceding taxation year 2015-10-31		N/A		N/A			
8th preceding taxation year 2014-12-31		N/A		N/A			
9th preceding taxation year 2013-12-31		N/A		N/A			
10th preceding taxation year 2012-12-31		N/A		N/A			
11th preceding taxation year 2011-12-31		N/A		N/A			
12th preceding taxation year 2010-12-31		N/A		N/A			
13th preceding taxation year 2009-12-31		N/A		N/A			
14th preceding taxation year 2008-12-31		N/A		N/A			
15th preceding taxation year 2007-12-31		N/A		N/A			
16th preceding taxation year 2006-12-31		N/A		N/A			
17th preceding taxation year 2005-12-31		N/A		N/A			
18th preceding taxation year 2004-12-31		N/A		N/A			
19th preceding taxation year 2003-12-31		N/A		N/A			
20th preceding taxation year 2002-12-31		N/A		N/A			*
Total	8,333,589	642,612					8,976,201

* **This balance expires this year and will not be available next year.**

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
Hydro One Remote Communities Inc.	[redacted]	2020-12-31

- Use this schedule if, during the tax year, your corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B, and D in Part 1)
  - is claiming provincial or territorial tax credits or rebates (see Part 2), or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- All legislative references are to the Income Tax Regulations.
- For more information, see the T2 Corporation – Income Tax Guide.
- For the regulation number to be entered in field 100 of Part 1, see the chart below.

Part 1 – Allocation of taxable income

100 Enter the regulation that applies (402 to 413)

A Jurisdiction. Tick yes if your corporation had a permanent establishment in the jurisdiction during the tax year *		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue attr butable to jurisdiction	E (D x taxable income) / H	F Alloca ion 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 descr bed under section 402, use the appropriate calculation descr bed 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 contr butions 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	395		
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal (line 278 **plus** line 280)		395	395	5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)			395	5I
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	9,000		
Ontario apprenticeship training tax credit (from Schedule 552)	454	2,158		
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)		11,158	11,158	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	-10,763	

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 -10,763

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.

Canada Revenue Agency Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	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 ☒

	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 hat 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		14,785,921	383,157	383,157				0	15,169,078
2.	2		70,966						0	70,966
3.	3		605						0	605
4.	6		4,168,267						0	4,168,267
5.	8		736,048	66,605	66,605				0	802,653
6.	10		192,685						0	192,685
7.	17		16,029,949	702,363	702,363				86,200	16,646,112
8.	43.1		290,603						0	290,603
9.	45		205						0	205
10.	47		7,915,281	330,120	46,641				0	8,245,401
11.	13	[redacted]	29,323						0	29,323
12.	13	[redacted]	35,251						0	35,251
13.	13	[redacted]	5,924						0	5,924
14.	14.1		13,383,957						0	13,383,957
15.	50		2,550	13,085	13,085				0	15,635
		Totals	57,647,535	1,495,330	1,211,851				86,200	59,056,665

	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 o her 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 me hod, 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			383,157	191,579		4	0	0	614,426	14,554,652
2.	2						6	0	0	4,258	66,708
3.	3						5	0	0	30	575
4.	6						10	0	0	416,827	3,751,440
5.	8			66,605	33,303		20	0	0	167,191	635,462
6.	10						30	0	0	57,806	134,879
7.	17		86,200	616,163	308,082		8	0	0	1,356,336	15,289,776
8.	43.1						30	0	0	87,181	203,422
9.	45						45	0	0	92	113
10.	47			46,641	23,321	141,740	8	0	0	650,159	7,595,242
11.	13	[redacted]					NA	0	0	4,233	25,090
12.	13	[redacted]					NA	0	0	1,107	34,144
13.	13	[redacted]					NA	0	0	3,000	2,924
14.	14.1						5	0	0	936,877	12,447,080
15.	50			13,085	6,543		55	0	0	12,198	3,437
		Totals	86,200	1,125,651	562,828	141,740				4,311,721	54,744,944

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 han 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 he 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 he 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 sec ion 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 he 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 disposi ion 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 he 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 excep ions, 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 me hod. 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 he 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 he 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 deduc ion)
- 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 mul iple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The addi ional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regula ions is eligible for he accelerated investment incen ive

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.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		1,495,330		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Other (specify):				
Current year capitalized allocations (Interest, OPEB, LTIP, etc.)	+	1,347,179		
Capital items deducted for book purposes	+	-285,372		
CIP increase (CY $3,686K - PY 2,494K)	+	1,192,000		
Future Use Asset increase (CY$ 4,534K - PY$ 3,541K)	+	993,000		
Total additions per books	=	4,742,137	▶	4,742,137
Proceeds up to original cost – Schedule 8 regular classes		86,200		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):				
Reg asset amortn included in depreciation add-back on S1	+	-870,252		
Asset removal costs included in depn add-back on S1	+	-360,992		
Rounding	+	-454		
Total proceeds per books	=	-1,145,498	▶ –	-1,145,498
Depreciation and amortization per accounts – Schedule 1			–	4,064,835
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	86,200
Net change per tax return			=	1,909,000

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		49,816,000
Opening net book value	–	47,907,000
Net change per financial statements	=	1,909,000

If the amounts from the tax return and the financial statements differ, explain why below.

Attached Schedule with Total

Other – Amount

Title Other – Amount

Description	Operator (Note)	Amount
Capitalized interest		172,814 00
Capitalized pension	+	229,495 00
Capitalized OPEB	+	307,467 00
Capitalized overhead	+	573,563 00
Capitalized union share grants	+	35,268 00
Capitalized LTIP	+	28,572 00
	+	
	+	
	Total	1,347,179 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Other – Amount

Title Other – Amount

Description	Operator (Note)	Amount
Removal costs		-360,992 00
Less: deductible removal costs	+	75,620 00
	+	
	+	
	Total	-285,372 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.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	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	Hydro One Limited	CA	[redacted]	3					
2	Hydro One Inc.	CA		1					
3	2486267 Ontario Inc.	CA		3					
4	2486268 Ontario Inc.	CA		3					
5	Hydro One Networks Inc.	CA		3					
6	Hydro One Telecom Inc.	CA		3					
7	Hydro One Telecom Link Limited	CA		3					
8	Municipal Billing Services Inc.	CA		3					
9	Hydro One Lake Erie Link Managem	CA		3					
10	1938454 Ontario Inc.	CA		3					
11	1943404 Ontario Inc.	CA		3					
12	Orillia Power Distribution Corporatic	CA		3					
13	Hydro One Indigenous Partnerships	CA		3					
14	Norfolk Energy Inc.	CA		3					
15	Norfolk Power Distribution Inc.	CA		3					
16	Haldimand County Energy Inc.	CA		3					
17	Haldimand County Hydro Inc.	CA		3					
18	Woodstock Hydro Services Inc.	CA		3					
19	Hydro One Sault Ste. Marie Holding	CA		3					
20	Hydro One Sault Ste. Marie Inc.	CA		3					
21	Hydro One Sault Ste. Marie Holding	CA		3					
22	1228185 Ontario Inc.	CA		3					
23	Hydro One East-West Tie Inc.	CA		3					
24	1937680 Ontario Inc.	CA		3					
25	1937681 Ontario Inc.	CA		3					
26	2587264 Ontario Inc.	CA		3					
27	Hydro One Holdings Limited	CA		3					
28	2587265 Ontario Inc.	CA		3					
29	Aux Energy Inc	CA		3					
30	Hydro One Investment Holdings Inc	CA		3					
31	Olympus Holding Corp.	US	NR	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	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	☐	110	115			120
Reserve for undelivered goods and services not rendered	X	130 92,880	135		1,321	140 91,559
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 92,880	275		1,321	280 91,559

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	OPEB Liability	17,333,145		1,037,431		18,370,576
2	Reg asset re OPEB Liability	-869,351		300,236		-569,115
3	Environmental Liabilities	34,095,083		9,283,552		43,378,635
4	Reg asset re Environ. Liabilities	-34,095,083			9,283,552	-43,378,635
5	Bonus accrual - 413741	5,267			5,267	
6	Reg Asset	-6,089,479		371,340		-5,718,139
7	Reg Asset Tax Rule changes	54,125			54,125	
8	LTIP Accrual			82,239		82,239
9						
	Reserves from Part 2 of Schedule 13	92,880			1,321	91,559
	Totals	10,526,587		11,074,798	9,344,265	12,257,120

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.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2020-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Networks Inc.	8th Floor South Tower 483 Bay Street Toronto ON CA M5G 2P5			661,804		
2	Hydro One Inc	8th Floor South Tower 483 Bay Street Toronto ON CA M5G 2P5			22,729		

T2 SCH 14 (99) Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	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)	Amount of contribution $ (see note 2)	Registration number (RPP, RSUBP, PRPP, and DPSP only)	Name of EPSP trust	Address of EPSP trust	T4PS slip(s) (see note 3)
	100	200	300	400	500	600
1	1	711,186	1059104			
2	1	10,499	1289982			

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 . . . . 721,685 A

Less:

Total of all amounts for deferred income plans deducted in your financial statements . . . . . 492,190 B

Deductible amount for contributions to deferred income plans
(amount A **minus** amount B) (if negative, enter "0") . . . . 229,495 C

Enter amount C on line 417 of Schedule 1

Note 3

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

Canada Revenue Agency / Agence du revenu du Canada

Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year
  - to claim a deduction against Part I tax payable
  - to claim a refund of credit earned during the current tax year
  - to claim a carryforward of credit from previous tax years
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1)
  - to request a credit carryback to one or more previous years
  - if you are subject to a recapture of ITC
  - if you are claiming:
    - the **Ontario Research and Development Tax Credit**
    - the **Ontario Innovation Tax Credit**
- Unless otherwise stated, all legislative references are to the Income Tax Act and the Income Tax Regulations.
- The ITC is elig ble for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that currently earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule)
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, Scientific Research and Experimental Development (SR&ED) Expenditures Claim
  - pre-production mining expenditures (Part 18)
    - You can no longer claim the ITC for the pre-production mining expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you made the investment.
  - apprenticeship job creation expenditures (Parts 19 to 21)
  - child care spaces expenditures (Parts 22 to 26)
    - Expenditures related to child care spaces incurred after March 21, 2017 no longer qualify for the ITC. However, if you entered into a written agreement before March 22, 2017, elig ble expenditures incurred before 2020 remain eligible for the credit.
- File this schedule with the T2 Corporation Income Tax Return. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, T2 Corporation – Income Tax Guide and read Information Circular IC78-4, Investment Tax Credit Rates, and its related Special Release.
- For more information on SR&ED, see guide T4088, Scientific Research and Experimental Development (SR&ED) Expenditures Claim – Guide to Form T661.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property at the time it files the income tax return for the year in which the property was acquired.
- An ITC deducted in a tax year for a depreciable property, other than a depreciable property deduct ble under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures.
- Expenditures for apprenticeship or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 Forms).
- For tax purposes, Canada includes the **exclusive economic zone of Canada** as defined in the Oceans Act (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).

Detailed information (continued)

- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012, unless transitional measures were granted*. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is elig ble for an ITC calculated at the 15% rate.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada	15 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred expenditures after March 18, 2007, and before March 22, 2017 (or before 2020 if you entered into a written agreement before March 22, 2017) for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2020-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if both of the following conditions are met:

- one corporation is associated with another corporation only because one or more persons own shares of the capital stock of both corporations
- one of the corporations has at least one shareholder who is not common to both corporations

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to one of the following:

a) one or more persons exempt from Part I tax under section 149

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority

c) any combination of persons referred to in a) or b) above

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contr bution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . **102** 1 Yes [ ] 2 No [X]

If **yes**, complete Schedule 125, Income Statement Information, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . ____________ x 80 % = **103** ____________

Enter on line 350 of Part 8.

* Enter only contributions not already included on Form T661.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**

Total of investments for qualified property and qualified resource property ____________ A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year			B1
Credit deemed as a remittance of co-op corporations	210		
Credit expired	215		
Subtotal (line 210 **plus** line 215)		▶	C1
ITC at the beginning of the tax year (amount B1 **minus** amount C1)		220	
Credit transferred on an amalgamation or the wind-up of a subsidiary	230		
ITC from repayment of assistance	235		
Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) ____ x 10 % =	240		
Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) ____ x 5 % =	242		
Credit allocated from a partnership	250		
Subtotal (total of lines 230 to 250)		▶	D1
Total credit available (line 220 **plus** amount D1)			E1
Credit deducted from Part I tax	260		
Credit carried back to previous years (amount H1 in Part 6)	a		
Credit transferred to offset Part VII tax liability	280		
Subtotal (total of line 260, amount a, and line 280)		▶	F1
Credit balance before refund (amount E1 **minus** amount F1)			G1
Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7)		310	
ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310)		320	

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day			
1st previous tax year				Credit to be applied	901	
2nd previous tax year				Credit to be applied	902	
3rd previous tax year				Credit to be applied	903	

Total of lines 901 to 903
Enter at amount a in Part 5. H1

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5)	I1
Credit balance before refund (from amount G1 in Part 5)	J1
Refund (40 % of amount I1 or J1, whichever is less)	K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter on line 780 of the T2 return if you do not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 559 on Form T661) . . . . ______

Contr butions to agricultural organizations for SR&ED . . . . ______

Deduct:

Government assistance, non-government assistance, or contract payment . . . . ______

Subtotal ______

x 80 %

Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)* . . . . ______ ► + ______

Qualified SR&ED expenditures (line 559 on Form T661 **plus** line 103 in Part 3)* . . . . ______ ► **350** ______

Repayments made in the year (from line 560 on Form T661) . . . . **370** ______

Total qualified SR&ED expenditures (line 350 **plus** line 370) . . . . **380** ______

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if both of the following apply:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation
- one of the corporations has at least one shareholder who is not common to both corporations

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . **385** 1 Yes ☐ 2 No ☐

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, complete Schedule 49, Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Expenditure Limit, to determine the amounts for associated corporations.

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied) . . . . **390** ______

Enter your taxable capital employed in Canada for the previous tax year **minus** $10 million. If this amount is nil or negative, enter "0".
If this amount is over $40 million, enter $40 million . . . . **398** ______

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation $ **8,000,000**

Taxable income for the previous tax year (line 390 in Part 9) or $500,000, whichever is more ______ x 10 = ______ A2

Excess ($8,000,000 **minus** amount A2; if negative, enter "0") . . . . ______ B2

$ 40,000,000 **minus** line 398 in Part 9 . . . . ______ b

Amount b **divided** by $ 40,000,000 . . . . ______ C2

For tax years ending before March 19, 2019
Amount B2 **multiplied** by amount C2 ______ D2

For tax years ending after March 18, 2019
multiplied by amount C2 ______ E2

Expenditure limit for the stand-alone corporation (amount D2 or amount E2, whichever applies)* ______ F2

For an associated corporation:
If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49* . . . . **400** ______ G2

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount F2 or G2 ______ x $\frac{\text{Number of days in the tax year}}{365}$ 366 = ... ______ H2

Your SR&ED expenditure limit for the year (enter amount F2, G2, or H2, whichever applies) . . . . **410** ______

* Amount F2 or G2 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Qualified SR&ED expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less*	420		x 35 % =		I2
Line 350 **minus** line 410 (if negative, enter "0")	430		x 15 % =		J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) ..... ________

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure for a CCPC**	460		x 35 % =		c
Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred before 2015	480		x 20 % =		d
Repayment of assistance made after September 16, 2016 that reduced a qualifying expenditure incurred after 2014	490		x 15 % =		e
Subtotal (total of amounts c to e)				▶	K2
Current-year SR&ED ITC (total of amounts I2 to K2; enter on line 540 in Part 12)					L2

* For corporations that are not CCPCs, enter "0" for amount I2.

** If you were a Canadian-controlled private corporation (CCPC), this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **Additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not elig ble for this rate use line 480 or 490 as appropriate.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				M2
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)			▶	N2
ITC at the beginning of the tax year (amount M2 **minus** amount N2)			520	
Credit transferred on an amalgamation or the wind-up of a subsidiary	530			
Total current-year credit (from amount L2 in Part 11)	540			
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)			▶	O2
Total credit available (line 520 **plus** amount O2)				P2
Credit deducted from Part I tax	560			
Credit carried back to previous years (amount S2 in Part 13)			f	
Credit transferred to offset Part VII tax liability	580			
Subtotal (total of line 560, amount f, and line 580)			▶	Q2
Credit balance before refund (amount P2 **minus** amount Q2)				R2
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED (amount R2 **minus** line 610)			620	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year Month Day			
1st previous tax year		Credit to be applied	911	
2nd previous tax year		Credit to be applied	912	
3rd previous tax year		Credit to be applied	913	
		Total of lines 911 to 913 Enter at amount f in Part 12.		S2

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes ☐ 2 No ☒

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) . . . . . ______ g

Refundable credits (amount g or amount R2 in Part 12, whichever is less)* . . . . . ______ T2

Amount T2 or amount I2 in Part 11, whichever is less . . . . . ______ U2

Net amount (amount T2 **minus** amount U2; if negative, enter "0") . . . . . ______ V2

Amount V2 **multiplied** by 40 % . . . . . ______ W2

Amount U2 . . . . . ______ X2

Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) . . . . . ______ Y2

Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (amount R2 in Part 12) . . . . . ______ Z2

Refund of ITC (amount Z2 or amount I2 in Part 11, whichever is less) . . . . . ______ AA2

Enter amount AA2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less

Subtotal Enter at amount C3 in Part 17. ______ A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at amount B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (total of column F) Enter at amount D3 in Part 17. ______ B3

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC Enter at amount E3 in Part 17.	760	

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16		C3
Recaptured ITC from calculation 2, amount B3 in Part 16		D3
Recaptured ITC from calculation 3, line 760 in Part 16		E3
Total recapture of SR&ED investment tax credit (total of amounts C3 to E3) Enter at amount A8 in Part 27.		F3

Pre-Production Mining

Part 18 – Account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year				A4
Credit deemed as a remittance of co-op corporations	841			
Credit expired	845			
Subtotal (line 841 **plus** line 845)			►	B4
ITC at the beginning of the tax year (amount A4 **minus** amount B4)			850	
Credit transferred on an amalgamation or the wind-up of a subsidiary			860	
Total credit available (line 850 **plus** line 860)				C4
Amount of unused credit carried forward from previous years and applied to reduce Part I tax payable in the current year			885	
ITC closing balance from pre-production mining expenditures (amount C4 **minus** line 885)			890	

Apprenticeship Job Creation

Part 19 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . 611 1 Yes X 2 No

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Elig ble salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	[redacted]	[redacted]	107,866	10,787	2,000
2.	[redacted]	[redacted]	79,369	7,937	2,000
			Total current-year credit (total of column E) Enter on line 640 in Part 20.		4,000 A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 20 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			10,795 B5
Credit deemed as a remittance of co-op corporations	612		
Credit expired after 20 tax years	615		
Subtotal (line 612 **plus** line 615)		▶	C5
ITC at the beginning of the tax year (amount B5 **minus** amount C5)		625	10,795
Credit transferred on an amalgamation or the wind-up of a subsidiary	630		
ITC from repayment of assistance	635		
Total current-year credit (amount A5 in Part 19)	640	4,000	
Credit allocated from a partnership	655		
Subtotal (total of lines 630 to 655)		4,000 ▶	4,000 D5
Total credit available (line 625 **plus** amount D5)			14,795 E5
Credit deducted from Part I tax	660		
Credit carried back to previous years (amount G5 in Part 21)		h	
Subtotal (line 660 **plus** amount h)		▶	F5
ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5)		690	14,795

Part 21 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day		
1st previous tax year				Credit to be applied 931	
2nd previous tax year				Credit to be applied 932	
3rd previous tax year				Credit to be applied 933	
				Total of lines 931 to 933 Enter at amount h in Part 20.	G5

Child Care Spaces

Part 22 – Eligible child care spaces expenditures

Enter the eligible expenditures that you incurred after March 18, 2007, and before March 22, 2017,* to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property)
- the specified child care start-up expenditures

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year (total of column 695) **715** ______

Specified child care start-up expenditures from the current tax year . . . . . **705** ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ______ A6

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6 . . . . . **725** ______

Excess (amount A6 **minus** line 725) (if negative, enter "0") . . . . . ______ B6

Repayments by the corporation of government and non-government assistance . . . . . **735** ______

Total eligible expenditures for child care spaces (amount B6 **plus** line 735) . . . . . **745** ______

* If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.

Part 23 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 22) . . . . . ______ x 25 % = ______ C6

Number of child care spaces . . . . . **755** ______ x $ 10,000 = ______ D6

ITC from child care spaces expenditures (amount C6 or D6, whichever is less) . . . . . ______ E6

Part 24 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F6
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			▶	G6
ITC at the beginning of the tax year (amount F6 **minus** amount G6)			775	
Credit transferred on an amalgamation or the wind-up of a subsidiary	777			
Total current-year credit (amount E6 in Part 23)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			▶	H6
Total credit available (line 775 **plus** amount H6)				I6
Credit deducted from Part I tax	785			
Credit carried back to previous years (amount K6 in Part 25)			i	
Subtotal (line 785 **plus** amount i)			▶	J6
ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6)			790	

Part 25 – Request for carryback of credit from child care space expenditures

	Year Month Day				
1st previous tax year	2019-12-31	Credit to be applied	941		
2nd previous tax year	2018-12-31	Credit to be applied	942		
3rd previous tax year	2017-12-31	Credit to be applied	943		
		Total of lines 941 to 943 Enter at amount i in Part 24.			K6

Recapture – Child Care Spaces

Part 26 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property, one of the following situations takes place:

- the new child care space is no longer available
- property that was an eligible expenditure for the child care space is
  - disposed of or leased to a lessee
  - converted to another use

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ______

In the case of elig ble expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . ______ A7

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 24. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799** ______

Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) . . . . ______ B7
Enter at amount B8 in Part 27.

Summary of Investment Tax Credits

Part 27 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount F3 in Part 17) . . . . ______ A8

Recaptured child care spaces ITC (amount B7 in Part 26) . . . . ______ B8

Total recapture of investment tax credit (amount A8 **plus** amount B8) . . . . ______ C8
Enter on line 602 of the T2 return.

Part 28 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5) . . . . ______ D8

ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12) . . . . ______ E8

ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 18) . . . . ______ F8

ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 20) . . . . ______ G8

ITC from child care space expenditures deducted from Part I tax (line 785 in Part 24) . . . . ______ H8

Total ITC deducted from Part I tax (total of amounts D8 to H8) . . . . ______ I8
Enter on line 652 of the T2 return.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
4,000				4,000

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2019-12-31	6,000			6,000
2018-12-31	2,795			2,795
2017-12-31	2,000			2,000
2016-12-31				
2015-12-31				
2015-11-04				
2015-10-31				
2014-12-31				
2013-12-31				
2012-12-31				*
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				*
Total	10,795			10,795

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	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	12,257,120		
Capital stock (or members' contributions if incorporated without share capital)	103	5,000,000		
Retained earnings	104			
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	42,817,000		
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)		60,074,120 ▶	60,074,120	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 descr bed 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)	60,074,120	A
Deduct the following amounts:				
Deferred tax debit balance at the end of the year	121	4,493,000		
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	4,651,976		
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)		9,144,976 ▶	9,144,976	B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		50,929,144	

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)		50,929,144	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	50,929,144	

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) 50,929,144 x (Taxable income earned in Canada **610** 1,000 / Taxable income 1,000) = **Taxable capital employed in Canada** **690** 50,929,144

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 descr bed 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 descr bed 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.

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
Hydro One Remote Communities Inc.	[redacted]	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	115,841,000
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	50,000,000
Total assets (total of lines 112 to 116)		165,841,000
Total revenue of the corporation for the tax year **	142	58,004,200
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	100,000,000
Total revenue (total of lines 142 to 146)		158,004,200

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	18,114
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220			
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal				A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320	3,476		
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		3,476		3,476 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	14,638

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	14,638	
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	14,638	

Amount from line 520: 14,638 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: 14,638 x Number of days in the tax year after June 30, 2010 366 / Number of days in the tax year 366 x 2.7 % = 395 2

Subtotal (amount 1 **plus** amount 2) ... 395 3

Gross CMT: amount on line 3 above x OAF **	540	395	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		395	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")		395	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 *		38,940 G		
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		38,940	620	38,940
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)				38,940 H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)				I
Subtotal (amount H **minus** amount I)				38,940 J
Add:				
Net CMT payable (amount E from Part 3)		395		
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		395		395 K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	39,335 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)			38,940 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)	395 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:		395 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)		11,158	
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
Hydro One Remote Communities Inc.	[redacted]	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	Hydro One Limited	[redacted]	0	0
2	Hydro One Inc.	[redacted]	0	0
3	2486267 Ontario Inc.	[redacted]	0	0
4	2486268 Ontario Inc.	[redacted]	0	0
5	Hydro One Networks Inc.	[redacted]	50,000,000	100,000,000
6	Hydro One Telecom Inc.	[redacted]	0	0
7	Hydro One Telecom Link Limited	[redacted]	0	0
8	Municipal Billing Services Inc.	[redacted]	0	0
9	Hydro One Lake Erie Link Management Inc.	[redacted]	0	0
10	1938454 Ontario Inc.	[redacted]	0	0
11	1943404 Ontario Inc.	[redacted]	0	0
12	Orillia Power Distribution Corporation	[redacted]	0	0
13	Hydro One Indigenous Partnerships Inc.	[redacted]	0	0
14	Norfolk Energy Inc.	[redacted]	0	0
15	Norfolk Power Distribution Inc.	[redacted]	0	0
16	Haldimand County Energy Inc.	[redacted]	0	0
17	Haldimand County Hydro Inc.	[redacted]	0	0
18	Woodstock Hydro Services Inc.	[redacted]	0	0
19	Hydro One Sault Ste. Marie Holdings Inc.	[redacted]	0	0
20	Hydro One Sault Ste. Marie Inc.	[redacted]	0	0
21	Hydro One Sault Ste. Marie Holding Corp.	[redacted]	0	0
22	1228185 Ontario Inc.	[redacted]	0	0
23	Hydro One East-West Tie Inc.	[redacted]	0	0
24	1937680 Ontario Inc.	[redacted]	0	0
25	1937681 Ontario Inc.	[redacted]	0	0
26	2587264 Ontario Inc.	[redacted]	0	0
27	Hydro One Holdings Limited	[redacted]	0	0
28	2587265 Ontario Inc.	[redacted]	0	0

	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
29	Aux Energy Inc	[redacted]	0	0
30	Hydro One Investment Holdings Inc.	[redacted]	0	0
31	Olympus Holding Corp.	NR	0	0
		Total	450 50,000,000	550 100,000,000

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.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2020-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not elig ble expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario elig ble educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return.*
- File this schedule with the *T2 Corporation Income Tax Return.*

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
Nancy Tran	(416) 345-6778

Is the claim filed for a CETC earned through a partnership?* . . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 8,967,020

For eligible expenditures incurred before March 27, 2009:

– If line 300 is $400,000 or less, enter 15% on line 310.
– If line 300 is $600,000 or more, enter 10% on line 310.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\textbf{minus}\; \$\;400{,}000}{\$\;200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

– If line 300 is $400,000 or less, enter 30% on line 312.
– If line 300 is $600,000 or more, enter 25% on line 312.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\textbf{minus}\; \$\;400{,}000}{\$\;200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other elig ble educational institution **400**	B Name of qualifying co-operative education program **405**
1.	University of Toronto	Engineering
2.	University of Toronto	Engineering
3.	University of Toronto	Engineering

	C Name of student **410**	D Start date of WP (see note 1 below) **430**	E End date of WP (see note 2 below) **435**
1.	[redacted]	2020-09-08	2020-12-31
2.	[redacted]	2020-01-01	2020-04-30
3.	[redacted]	2020-05-01	2020-08-13

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Elig ble percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	16,672	25.000 %		15
2.		10.000 %	24,760	25.000 %		16
3.		10.000 %	24,760	25.000 %		14

	G Elig ble amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	4,168	3,000	3,000		3,000
2.	6,190	3,000	3,000		3,000
3.	6,190	3,000	3,000		3,000

Ontario co-operative education tax credit (total of amounts in column K) 500 9,000 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = ... M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 552

Ontario Apprenticeship Training Tax Credit

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2020-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015, the maximum credit for each qualifying apprenticeship is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. For an apprenticeship program that began after April 23, 2015, the maximum credit for each qualifying apprenticeship is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if an apprenticeship program began before April 24, 2015; and
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if an apprenticeship program began after April 23, 2015.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario) or a person designated by him or her; and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009,* or the *Apprenticeship and Certification Act, 1998,* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*. Keep a copy of the training agreement or contract of apprenticeship to support your claim.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number
Nancy Tran	(416) 345-6778

Is the claim filed for an ATTC earned through a partnership? * . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 8,967,020

For eligible expenditures incurred after March 26, 2009 for an apprenticeship program that began before April 24, 2015:

- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **312** 35.000 %

For eligible expenditures incurred for an apprenticeship program that began after April 23, 2015:

- If line 300 is $400,000 or less, enter 30% on line 314.
- If line 300 is $600,000 or more, enter 25% on line 314.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 314 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . . **314** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice for each qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/trade name 405	C Name of apprentice 410
1.	[redacted]	[redacted]	[redacted]
2.			

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (YYYYMMDD) (see note 1) 425	F Start date of employment as an apprentice in the tax year (YYYYMMDD) (see note 2) 430	G End date of employment as an apprentice in the tax year (YYYYMMDD) (see note 3) 435
1.	[redacted]	2017-06-08	2020-01-01	2020-06-07
2.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Ontario apprenticeship training tax credit (continued)

	H1 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began before April 24, 2015 (see note 1) 442	H2 Number of days in the tax year employed as an apprentice in a qualifying apprenticeship program that began after April 23, 2015 (see note 1) 443	I Maximum credit amount for the tax year (see note 2) 445
1.		158	2,158
2.			

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 48 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 36 months of the registration date provided in column E.

Note 2: Maximum credit = ($10,000 × H1/365*****) or ($5,000 × H2/365*****), whichever applies.
***** 366 days, if the tax year includes February 29

	J1 Eligible expenditures incurred after March 26, 2009 for a qualifying apprenticeship program that began before April 24, 2015 (see note 3) 452	J2 Eligible expenditures incurred for a qualifying apprenticeship program that began after April 23, 2015 (see note 3) 453	K Eligible expenditures **multiplied** by specified percentage (see note 4) 460
1.		77,746	19,437
2.			

Note 3: Reduce elig ble expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the elig ble expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 48 months of the apprenticeship program, and not relating to services performed before the apprenticeship program began or after it ended.
For J2: Eligible expenditures must be for services provided by the apprentice to the taxpayer during the first 36 months of the apprenticeship program, and not relating to services performed before the apprenticeship began or after it ended.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 × line 312) or (J2 × line 314), whichever applies.

	L ATTC on elig ble expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5) 480	N ATTC for each apprentice (column L or M, whichever applies) 490
1.	2,158		2,158
2.			

Ontario apprenticeship training tax credit (total of amounts in column N) 500 2,158 **O**

Or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ______ % = ... ________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, **add** the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year. Complete a **separate entry** for each repayment of government assistance.

See the privacy notice on your return.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . Hydro One Remote Communities Inc.

Taxation Year . . . . 2020-01-01 to 2020-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 31

Type of corporation . . . . Corporation Controlled by a Public Corporation

Total amount due (refund) federal and provincial* . . . . -26,590

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		-642,612
Taxable income		
Donations		
Calculation of income from an active business carried on in Canada		
Dividends paid		
Dividends paid – Regular		
Dividends paid – Elig ble		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		695,420
Balance of the general rate income pool at the end of the year		
Part I tax (base amount)		

Credits against Part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I		ITC refund	
M&P deduction		Part IV		Dividends refund:	
Foreign tax credit		Part III.1		– Elig ble dividends	
Investment tax credits		Other*		– Non-eligible dividends	
Abatement/Other*		Provincial or territorial tax		Instalments	15,827
				Other*	10,763
				Balance due/refund (–)	-26,590

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Investment tax credits	14,795
Non-capital losses	8,976,201
Financial statement reserve	12,257,120
Other reserves	91,559

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	-642,612		
Taxable income			
% Allocation	100.00		
Attr buted taxable income			
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attr buted taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	395		
Instalments and refundable credits	11,158		
Balance due/Refund (-)	-10,763		
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510 . . . 39,335

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
			50,929,144	50,929,144
Hydro One Limited				
Hydro One Inc.				
2486267 Ontario Inc.				
2486268 Ontario Inc.				
Hydro One Networks Inc.			10,000,000	10,000,000
Hydro One Telecom Inc.				
Hydro One Telecom Link Limited				
Municipal Billing Services Inc.				
Hydro One Lake Erie Link Management Inc.				
1938454 Ontario Inc.				
1943404 Ontario Inc.				
Orillia Power Distribution Corporation				
Hydro One Indigenous Partnerships Inc.				
Norfolk Energy Inc.				
Norfolk Power Distribution Inc.				
Haldimand County Energy Inc.				
Haldimand County Hydro Inc.				
Woodstock Hydro Services Inc.				
Hydro One Sault Ste. Marie Holdings Inc.				

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Hydro One Sault Ste. Marie Inc.				
Hydro One Sault Ste. Marie Holding Corp.				
1228185 Ontario Inc.				
Hydro One East-West Tie Inc.				
1937680 Ontario Inc.				
1937681 Ontario Inc.				
2587264 Ontario Inc.				
Hydro One Holdings Limited				
2587265 Ontario Inc.				
Aux Energy Inc				
Hydro One Investment Holdings Inc.				
Olympus Holding Corp.				
Total			60,929,144	60,929,144

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN) and to determine the applicability of Forms CO-1029.8.33.CS and CO-1029.8.33.TE	Paid-up capital used to calculate the $1 million deduction (CO-1137.A and CO-1137.E)	Paid-up capital used to determine the applicability of Form CO-737.SI
Total				

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Alberta

Corporate name	Taxable capital used to calculate the Alberta innovation employment grant (Schedule A29)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2020-12-31**	**2019-12-31**	**2018-12-31**	**2017-12-31**	**2016-12-31**
Net income	-642,612	-2,789,810	-5,039,814	-306,376	-404,460
Taxable income					
Active business income					
Dividends paid					
Dividends paid – Regular					
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	695,420	695,420	695,420	695,420	695,420
GRIP – end of the year					
Donations					
Balance due/refund (-)	-26,590	-15,774	-481,059	-445,609	-401,909
Line 996 – Amended tax return	☐	☐	☐	X	☐

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	**2020-12-31**	**2019-12-31**	**2018-12-31**	**2017-12-31**	**2016-12-31**
Taxable income before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted taxable income after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	**2020-12-31**	**2019-12-31**	**2018-12-31**	**2017-12-31**	**2016-12-31**
Adjusted taxable income before current year loss carrybacks*	N/A				N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A				N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2020-12-31	2019-12-31	2018-12-31	2017-12-31	2016-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2020-12-31	2019-12-31	2018-12-31	2017-12-31	2016-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks***	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A				N/A

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2020-12-31	2019-12-31	2018-12-31	2017-12-31	2016-12-31
Part I					
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against Part I tax

Taxation year end	2020-12-31	2019-12-31	2018-12-31	2017-12-31	2016-12-31
Small business deduction					
M&P deduction					
Foreign tax credit					
Investment tax credit					
Abatement/other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2020-12-31	2019-12-31	2018-12-31	2017-12-31	2016-12-31
ITC refund					
Dividend refund					
– Eligible dividends					
– Non-eligible dividends					
Instalments	15,827		460,355	432,571	372,676
Other*	10,763	15,774	20,704	13,038	29,233

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2020-12-31	2019-12-31	2018-12-31	2017-12-31	2016-12-31
Net income	-642,612	-2,789,810	-5,039,814	-306,376	-404,460
Taxable income					
% Allocation	100.00	100.00	100.00	100.00	100.00
Attr buted taxable income					
Surtax					
Income tax payable before deduction					
Income tax deductions /credits					
Net income tax payable					
Taxable capital					
Capital tax payable					
Total tax payable*	395	403	391	13,017	12,439
Instalments and refundable credits	11,158	16,177	21,095	26,055	41,672
Balance due/refund**	-10,763	-15,774	-20,704	-13,038	-29,233

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Attached Notes – Summary

☐ Name of the cell: Part 1 – Financial statement reserves – Description | Form: Sch. 13S - Continuity of financial statement reserves (not deduc

this is to offset the movement in RRPR that is balance sheet movement only.

210614 - 2020-06-26 | Keep this note when rolling forward the file ☒

☐ Name of the cell: GIFI code 8000 – Amount – Trade sales of goods and services | Form: Sch. 8299 - Revenue

B.1

208974 - 2021-04-27 | Keep this note when rolling forward the file ☐

☐ Name of the cell: GIFI code 8408 – Amount – Well operating, fuel and equipment | Form: Sch. 8518 - Cost of sales

B.1

208974 - 2021-04-27 | Keep this note when rolling forward the file ☐

☐ Name of the cell: GIFI code 8450 – Amount – Other direct costs | Form: Sch. 8518 - Cost of sales

B.1

208974 - 2021-04-27 | Keep this note when rolling forward the file ☐

☐ Name of the cell: GIFI code 8714 – Amount – Interest on long-term debt | Form: Sch. 9367 - Operating expenses

B.1

208974 - 2021-04-27 | Keep this note when rolling forward the file ☐

Name of the cell Attached schedule – Amount
Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell GIFI code 1062 – Trade accounts receivable
Form Sch. 1599 - Current assets

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell GIFI code 1066 – Taxes receivable
Form Sch. 1599 - Current assets

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell GIFI code 1122 – Inventory parts and supplies
Form Sch. 1599 - Current assets

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell GIFI code 1480 – Other current assets
Form Sch. 1599 - Current assets

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1 Note 8

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1 Note 8

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1 Note 8

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1 Note 8

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Tangible capital property – GIFI code 1900 – Other tangible cap Form Sch. 2008 & 2009 - Tangible capital assets and accumulated am

B.1 Note 8

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 1901 – Accumulated amortization of other tangible ca Form Sch. 2008 & 2009 - Tangible capital assets and accumulated am

B.1 Note 8

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Tangible capital property – GIFI code 1920 – Other capital asset Form Sch. 2008 & 2009 - Tangible capital assets and accumulated am

B.1 Note 8

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 2421 – Future (deferred) income taxes Form Sch. 2589 - Long-term assets

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 2860 – Due to related parties Form Sch. 3139 - Current liabilities

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 2629 – Interest payable Form Sch. 3139 - Current liabilities

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 3140 – Long-term debt
Form Sch. 3450 - Long-term liabilities

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount
Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount
Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount
Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount
Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 3500 – Common shares Form Sch. 3620 - Shareholder equity

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 3580 – Accumulated other comprehensive income Form Sch. 3620 - Shareholder equity

B.1

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 9990 – Amount – Current income taxes Form Sch. 140 - Income statement summary

B.2

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 8210 – Amount – Realized gains/losses on disposal of Form Sch. 8299 - Revenue

B.2 GL 741510

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 8670 – Amount – Amortization of tangible assets Form Sch. 9367 - Operating expenses

C.1 Tab 1.0

Removal costs = 360,992.2
Depreciation expense = 2,833,589.9
Amortization - reg asset = 870,252.5
Total = 4,064,835

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 8523 – Amount – Meals and entertainment Form Sch. 9367 - Operating expenses

1.1a non-deductible M&E = $33,914
Full amount = 67,828

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

1.1a

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 7008 – Cash flow hedge effective portion gains/losses Form Sch. 9998 - Other comprehensive income

B.2 GL551000

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell GIFI code 8623 – Amount – Contributions to deferred income pl Form Sch. 9367 - Operating expenses

1.2

208974 - 2021-04-27 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount
Form Schedule - Attached schedule with total

1.2

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Is contingent liability information mentioned in the notes?
Form Sch. 141 - Notes checklist

B.1 Note 18

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Is information regarding commitments mentioned in the notes?
Form Sch. 141 - Notes checklist

B.1 Note 19

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Is re-evaluation of asset information mentioned in the notes?
Form Sch. 141 - Notes checklist

B.1 Note 11

208974 - 2021-04-27
Keep this note when rolling forward the file

Name of the cell Amount of contribution
Form Sch. 15 - Deferred income plans

1.2

208974 - 2021-04-28
Keep this note when rolling forward the file

Name of the cell Amount of contribution Form Sch. 15 - Deferred income plans

1.2

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

1.3

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

1.4

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Line 216 – Financing fees deducted in books Form Sch. 1 - Net income (loss) for income tax purposes

1.7

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

1.9

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

1.9

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Line 295 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

1.10

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Line 395 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

13.1

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Add Form Sch. 13S - Continuity of financial statement reserves (not deduc

13.1

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Add Form Sch. 13S - Continuity of financial statement reserves (not deduc

13.2

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Line 395 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

13.2

208974 - 2021-04-28 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Deduct Form Sch. 13S - Continuity of financial statement reserves (not deduc

13.3

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Add Form Sch. 13S - Continuity of financial statement reserves (not deduc

13.3

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Add Form Sch. 13S - Continuity of financial statement reserves (not deduc

13.3

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Deduct Form Sch. 13S - Continuity of financial statement reserves (not deduc

13.3

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Deduct Form Sch. 13S - Continuity of financial statement reserves (not deduc

13.4

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Line 395 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

8.1

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITR Form Sch. 8 - Capital cost allowance (CCA) workchart

8.2

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITR Form Sch. 8 - Capital cost allowance (CCA) workchart

8.2

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITR Form Sch. 8 - Capital cost allowance (CCA) workchart

8.2

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Federal – Current-year disposals Form Sch. 8 - Capital cost allowance (CCA) workchart

8.2

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITR Form Sch. 8 - Capital cost allowance (CCA) workchart

8.2

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Federal – Cost of acquisitions from column 3 that are accelerate Form Sch. 8 - Capital cost allowance (CCA) workchart

8.2

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITR Form Sch. 8 - Capital cost allowance (CCA) workchart

8.2

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Part 2 – Other reserves – Deduct – Reserve for undelivered good Form Sch. 13 - Continuity of reserves

TB GL 200391010 Customer Security Deposit Account

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Add Form Sch. 13S - Continuity of financial statement reserves (not deduc

13.6

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Management fees Form Sch. 14 - Miscellaneous payments to residents

14.1

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Management fees Form Sch. 14 - Miscellaneous payments to residents

14.1

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Corporation's salaries and wages paid in the previous tax year Form ON Sch. 552 - Apprenticeship training tax credit

1.10c

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Amount of credit Form T7B-1 - Schedule of instalment remittances

I.1

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Other – Amount
Form Sch. 8 - Fixed assets reconciliation

8.1

208974 - 2021-04-29
Keep this note when rolling forward the file

Name of the cell Other – Amount
Form Sch. 8 - Fixed assets reconciliation

8.1

208974 - 2021-04-29
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount
Form Schedule - Attached schedule with total

8.3

208974 - 2021-04-29
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount
Form Schedule - Attached schedule with total

8.3

208974 - 2021-04-29
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount
Form Schedule - Attached schedule with total

8.3

208974 - 2021-04-29
Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

8.3

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

8.3

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

8.3

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

8.3

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

8.3

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Other – Amount Form Sch. 8 - Fixed assets reconciliation

FS Note 8

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Other – Amount Form Sch. 8 - Fixed assets reconciliation

FS Note 8

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Part 1 – Reserves that have not been deducted in calculating inc Form Sch. 33 - Taxable capital employed in Canada - Large corporatio

Sch 13S

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Part 1 – All indebtedness of the corporation represented by bon Form Sch. 33 - Taxable capital employed in Canada - Large corporatio

B.1 FS

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Part 1 – Deferred tax debit balance at the end of the year Form Sch. 33 - Taxable capital employed in Canada - Large corporatio

B.1 FS

208974 - 2021-04-29 Keep this note when rolling forward the file

Name of the cell Corporation's salaries and wages paid in the previous tax year Form ON Sch. 550 - Co-operative education tax credit

1.10c

208974 - 2021-06-01 Keep this note when rolling forward the file

Name of the cell Net income (loss) after taxes and extraordinary items from line Form Sch. 1 - Net income (loss) for income tax purposes

FS

205191 - 2021-06-04 Keep this note when rolling forward the file

Name of the cell Line 101 – Provision for income taxes – current Form Sch. 1 - Net income (loss) for income tax purposes

FS

205191 - 2021-06-04 Keep this note when rolling forward the file

Name of the cell Line 104 – Amortization of tangible assets Form Sch. 1 - Net income (loss) for income tax purposes

FS

205191 - 2021-06-04 Keep this note when rolling forward the file

Name of the cell Line 401 – Gain on disposal of assets per financial statements Form Sch. 1 - Net income (loss) for income tax purposes

FS

205191 - 2021-06-04 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Balance at the Form Sch. 13S - Continuity of financial statement reserves (not deduc

FS note 12

205191 - 2021-06-04 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Balance at the Form Sch. 13S - Continuity of financial statement reserves (not deduc

FS note 13

205191 - 2021-06-04 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Balance at the Form Sch. 13S - Continuity of financial statement reserves (not deduc

FS Note 9

205191 - 2021-06-04 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Balance at the Form Sch. 13S - Continuity of financial statement reserves (not deduc

Fs nOte 9

205191 - 2021-06-04 Keep this note when rolling forward the file

Name of the cell Line 395 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

1.10

208974 - 2021-06-24 Keep this note when rolling forward the file

200

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

055 **Do not use this area**

Filed: 2022-08-31
EB-2022-0041
Exhibit D-5-2
Attachment 2
Page 1 of 126

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 [redacted]

Corporation's name
002 Hydro One Remote Communities Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . 010 Yes [ ] No [X]
If **yes**, complete lines 011 to 018.
011 483 BAY STREET 8TH FLOOR
012 SOUTH TOWER
City: 015 TORONTO
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal or ZIP code: 018 M5G 2P5

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 TAX DEPARTMENT
022 483 BAY STREET 8TH FLOOR
023 SOUTH TOWER
City: 025 TORONTO
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal or ZIP code: 028 M5G 2P5

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.
031 483 BAY STREET 8TH FLOOR
032 SOUTH TOWER
City: 035 TORONTO
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal or ZIP code: 038 M5G 2P5

040 **Type of corporation at the end of the tax year** (tick one)
- [ ] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [X] 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 (Year Month Day): 060 2021-01-01
Tax year-end (Year Month Day): 061 2021-12-31

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.

Question	Line	Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170		29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		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	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	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	X	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
Is the corporation claiming a return of fuel charge proceeds to farmers tax credit?	273		63
Are you an employer reporting a non-qualified security agreement under subsection 110(1.9)?	274		59
Is the corporation claiming an air quality improvement tax credit?	275		65

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	Electricity generation and distribution	285	100.000 %
286		287	%
288		289	%

		Yes	No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was elig ble to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be elig ble 294 Year Month Day

		Yes	No
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295		

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI			300	-5,412,024 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	352			
Subtotal			▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360	
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7 . . . . . 400 ______ 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 ______ 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 ______ x 415 *** ______ D / 11,250 = ... ______ E

Passive income business limit reduction

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

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

The greater of amount E and amount G 422 ______ 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	______	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)	______	K	x 30 2/3 % = ______	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 elig ble 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-elig ble 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 notice

Personal information (including the SIN) is collected to administer or enforce 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 the 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 paying interest or penalties, or in 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		
Return of fuel charge proceeds to farmers tax credit from Schedule 63	795		
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		
Air quality improvement tax credit from Schedule 65	799		
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	5,483	
Tax instalments paid	840	14,462	
Total credits	890	19,945	▶ 19,945 B
Balance (amount A **minus** amount B)			-19,945

If the result is negative, you have **a refund**. If the result is positive, you have a **balance owing**.
Enter the amount below on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Refund code 894 2 Refund 19,945 Balance owing

For information on how to enrol for direct deposit, go to **canada.ca/cra-direct-deposit**.

For information on how to make your payment, go to **canada.ca/payments**.

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

Certification

I, 950 Tran (Last name) 951 Nancy (First name) 954 Vice President - Corporate Tax (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 2022-06-17 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (416) 345-6778 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

Schedule of Instalment Remittances

Name of corporation contact: Nancy Tran
Telephone number: (416) 345-6778

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	14,462

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 14,462 **A**

Total instalments credited to the taxation year per T9 14,462 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	17,805,000	14,417,000
	Total tang ble capital assets	2008	+	83,366,000	79,821,000
	Total accumulated amortization of tangible capital assets	2009	–	31,570,000	30,005,000
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	54,632,000	51,608,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	124,233,000	115,841,000
	Liabilities				
	Total current liabilities	3139	+	18,470,000	10,127,976
	Total long-term liabilities	3450	+	105,856,000	105,826,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	124,326,000	115,953,976
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	-93,000	-112,976
	Total liabilities and shareholder equity	3640	=	124,233,000	115,841,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	-4,651,000	-4,651,976

* Generic item

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
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

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	+	63,271,000	57,918,000
	Cost of sales	8518	–	36,065,000	30,945,000
	Gross profit/loss	8519	=	27,206,000	26,973,000
	Cost of sales	8518	+	36,065,000	30,945,000
	Total operating expenses	9367	+	27,206,000	27,062,676
	Total expenses (mandatory field)	9368	=	63,271,000	58,007,676
	Total revenue (mandatory field)	8299	+	63,271,000	58,004,200
	Total expenses (mandatory field)	9368	–	63,271,000	58,007,676
	Net non-farming income	9369	=		-3,476
	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	=		-3,476
	Total – other comprehensive income	9998	=	19,140	18,114
	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	–	167	-3,476
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+	19,140	18,114
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	18,973	18,114

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes Checklist

Corporation's name	Business number	Tax Year End Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- Fill out this schedule to identify who prepared or reported on the financial statements, the extent of their involvement and to identify the type of information contained in the notes to the financial statements. If the person preparing the tax return is not the person referred to above, they must still complete Parts 1, 2, 3, 4 and 5, 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 person who prepared or reported on the financial statements

Were financial statements prepared? . . . . . 111 Yes [X] No [ ]

If you answered **no**, go to part 5.

Does the person who prepared or reported on the financial statements have an accounting professional designation? . . . . . 095 Yes [X] No [ ]

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

Note: If that person does not have an accounting professional designation or is connected with the corporation, go to part 4.

* 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 person referred to in part 1: 198

- Completed an auditor's report . . . . . [X] 1
- Completed a review engagement report . . . . . [ ] 2
- Conducted a compilation engagement . . . . . [ ] 3
- Other . . . . . [ ] 4

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 person referred to in part 1 expressed a reservation? . . . . . 099 Yes [ ] No [X]

Part 4 – Other information

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 [X] No [ ]
- 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 ☒

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 ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** Yes ☐ No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** Yes ☐ No ☒

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 ☒

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

Part 5 – Information on the person who prepared the information return

If the person that prepared the information return has an accounting professional designation but is not the person associated with the financial statements in part 1 above, choose one of the following options, if applicable: **110**

Financial statements provided by client . . . . . ☐ 1

Prepared the information return and the financial information contained therein . . . . . ☐ 2

Corporation's name	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

General Index of Financial Information

Notes to the financial statements

Entity: Hydro One Remote Communities Inc. (the "Taxpayer")
Business Number: [redacted]
Taxation Year: December 31, 2021
Subject: 13(7.4) Election

The Taxpayer is electing under subsection 13(7.4) of the Income Tax Act with respect to amounts that would normally be included in income under paragraph 12(1)(x). The amount elected to reduce the cost of depreciable property instead of being included in income is $6,953,195

1. DESCRIPTION OF THE BUSINESS

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the Business Corporations Act (Ontario) and is a wholly-owned subsidiary of Hydro One Inc. (Hydro One), which is wholly owned by Hydro One Limited. Hydro One Remote Communities generates and distributes electricity to customers in 21 off grid communities in northern Ontario and distributes to one community connected to the Province's electricity grid. The Company's business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On November 3, 2020, Hydro One Remote Communities filed an application with the OEB seeking approval for an increase to 2020 base rates of 2.0%, which was subsequently updated to 2.2% on January 11, 2021, effective May 1, 2021. On March 1, 2021, the OEB issued a draft decision approving the requested increase, which was later finalized on March 25, 2021. On November 3, 2021, Hydro One Remote Communities filed an application with the OEB seeking approval for an increase to 2021 base rates of 2.2%, which was subsequently updated to 3.3% on January 4, 2022, effective May 1, 2022. On March 24, 2022, the OEB approved the 3.3% rate increase.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. The Company uses a cost recovery model applied to achieve breakeven net income and the Financial Statements are prepared for the use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2021 have been prepared and are publicly available.

Hydro One Remote Communities performed an evaluation of subsequent events through to April 27, 2022, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any

General Index of Financial Information

Notes to the financial statements

adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, contingencies, and unbilled revenues. Actual results may differ significantly from these estimates.
Since late March 2020, the impact of COVID-19 has been reflected in the Company's financial statements. The Company has analyzed the impact of the pandemic on its estimates and assumptions that affect its financial results as at and for the year ended December 31, 2021 and has determined that there was no material impact.
As the duration of the pandemic remains uncertain, the Company continues to assess its impact to the Company's financialresults and operations.
Regulatory Accounting
The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations prospectively from the date the Company's assessment is made, unless the change meets the requirements for a subsequent event adjustment.
Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of income taxes. Any excess or deficiency in Rural and Remote Rate Protection (RRRP) amounts necessary to lead to breakeven net income is added to, or drawn from, the RRRP variance account. The balance in the RRRP variance account is subject to future review and disposition by the OEB.
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS
For the years ended December 31, 2021 and 2020
7
Revenue Recognition
Revenues attributable to the generation and delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues.
Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, volume of electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Corporation's name	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

General Index of Financial Information

Notes to the financial statements

Distribution revenue also includes RRRP which is an amount relating to rate protection for remote customers received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides RRRP for prescribed classes of rural, residential and remote consumers by reducing the electricity rates thatwould otherwise apply. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses (CECL) for all accounts receivable balances. The Company estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economicconditions.

Long-term accounts receivable are recorded at their invoiced amount, net of allowance for doubtful accounts and represent amounts due from specified First Nation communities. The component of long-term accounts receivable that is energy-related does not bear interest. These amounts are reduced by fixed-interval payments, received monthly throughout the term of the agreement. The CECL for this component is set at the inception of the balance and is maintained until settlement of those amounts. The CECL for this component is monitored and adjusted only if required with management discretion. The component of long-term accounts receivable that is non-energy related is reduced annually by a fixed incremental amount which is expensed through performance of the associated contract. There is no provision associated with these amounts.Income Taxes

Income taxes are accounted for using the asset and liability method. Current tax assets and liabilities are recognized based on the taxes payable or refundable on the current and prior year's taxable income. Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.Deferred Income Taxes

General Index of Financial Information

Notes to the financial statements

Deferred income tax assets and liabilities are recognized on all temporary differences between the tax bases and carrying
amounts of assets and liabilities, including the carry forward unused tax credits and tax losses to the extent that it is more-likelythan-
not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the
tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and
tax laws that have been enacted as at the balance sheet date.
Deferred income taxes associated with its regulated operations which are considered to be more-likely-than-not to be
recoverable or refunded in the future regulated rates charged to customers are recognized as deferred income tax regulatory
assets and liabilities with an offset to deferred income tax expense.
Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period
to the extent it is more likely than not that the credits can be utilized.
Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it
is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax
assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that
the tax benefit will be realized.
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
8
Inter-company Demand Facility
Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote
Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and
withdrawals made by the Company to and from the pooled cash accounts. Interest is earned on positive inter-company balances
based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on
overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.Fuel, Materials and Supplies
Fuel is used in the generation of electricity. Materials and supplies represent consumables, small spare parts and construction
materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average
cost less any impairments recorded.
Property, Plant and Equipment
Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment
losses. The cost of additions, including betterments and replacement asset components, is included on the balance sheets asproperty, plant and equipment.
The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits),
contracted services, attributable capitalized financing costs, and direct and indirect overheads that are related to the capital
project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and
information technology. Overhead costs, including corporate functions and

General Index of Financial Information

Notes to the financial statements

field services costs, are capitalized on a fully allocated
basis, consistent with an OEB-approved methodology.
Property, plant and equipment in service consists of generation,
distribution, and administration and service assets. Property,
plant and equipment also includes future use assets, such as major components
and spare parts and capitalized project
development costs associated with deferred capital projects.
Generation
Generation assets are used in the generation of electricity, including
hydroelectric equipment, wind turbines, diesel generators,and tank farms.
Distribution
Distribution assets include assets related to the distribution of low-voltage
electricity, including lines, poles, switches,
transformers, protective devices, and metering systems.
Administration and Service
Administration and service assets include administrative buildings, personal
computers, tools, and other minor assets.Capitalized Financing Costs
Capitalized financing costs represent interest costs attributable to the
construction of property, plant and equipment. The
financing cost of attributable borrowed funds is capitalized as part of the
acquisition cost of such assets. The capitalized
financing costs are a reduction of financing charges recognized in the
statements of operations and comprehensive income
(loss). Capitalized financing costs are calculated using the Company's
weighted average effective cost of debt.Construction in Progress
Construction in progress consists of the capitalized cost of constructed
assets that are not yet complete and which have not yetbeen placed in service.
Depreciation
The cost of property, plant and equipment is depreciated on a straight-line
basis based on the estimated remaining service life of
each asset category. The Company periodically initiates an external
independent review of its property, plant and equipment
depreciation rates, as required by the OEB. Any changes arising from such a
review are implemented on a remaining service life
basis, consistent with their inclusion in electricity rates. The last review
resulted in changes to rates effective January 1, 2013.
A summary of average service lives and depreciation and amortization rates
for the various classes of assets is included below:Average Rate
Service Life Range Average
Generation 20 3% - 7% 5 %
Distribution 44 1% - 7% 2 %
Administration and service 38 3% - 20% 3 %
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
9
In accordance with group depreciation practices, the original cost of
property, plant and equipment, or major components thereof,
that are normally retired, is charged to accumulated depreciation with no
gain or loss being reflected in results of operations.
Where a disposition of property, plant and equipment occurs through sale, a
gain or loss is calculated based on proceeds and
such gain or loss is included in depreciation expense.
Long-Lived Asset Impairment
When circumstances indicate the carrying value of long-lived assets may not
be recoverable, the Company evaluates whether

General Index of Financial Information

Notes to the financial statements

the carrying value of such assets has been impaired. For such long-lived assets, the Company evaluates whether impairment
may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the
asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a
probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the longlived
asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured
as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to itsestimated fair value.
The carrying costs of most of Hydro One Remote Communities' long-lived assets are included in rate base where they earn an
OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result,
such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a
disallowance is judged to be probable. As at December 31, 2021 and 2020, no asset impairment had been recorded.Costs of Arranging Debt Financing
For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to
obtaining debt financing and presents such amounts net of related debt on the balance sheets. Deferred debt issuance costs are
amortized over the contractual life of the related debt on an effective-interest rate basis and the amortization is included within
financing charges in the statements of operations and comprehensive income (loss). Transaction costs for items classified as
held-for-trading are expensed immediately.
Comprehensive Income
Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net
unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges. The
Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the
effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents net income
and OCI in a single continuous statement of operations and comprehensive income (loss).Financial Assets and Liabilities
All financial assets and liabilities are classified into one of the following five categories (i) held-to-maturity, (ii) loans and
receivables, (iii) held-for-trading, (iv) other liabilities, or (v) available-for-sale. Financial assets and liabilities classified as held-fortrading
are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts
receivable which are measured at its net realizable value. Accounts receivable are classified as loans and receivables. The
Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short
time to maturity of these instruments. The Company estimates the CECL for all accounts receivable balances, which are
recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance
when they are deemed uncollectible.

General Index of Financial Information

Notes to the financial statements

The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in note 11 - Fair Value of Financial Instruments and Risk Management.Derivative Instruments and Hedge Accounting
The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2021 and 2020. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.
Employee Future Benefits
Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employeesrender service.
Hydro One recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and postemployment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on theHYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
10
consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.
Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.Defined Benefit Pension
Hydro One has a contributory Pension Plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group.
Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution pension plan and no pension benefit asset or liability is recorded.
Post-retirement and Post-employment Benefits
Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations

of these post-retirement and post-employment
benefit plans are not segregated, or funded separately, for Hydro One Remote
Communities. Accordingly, for purposes of these
Financial Statements, the post-retirement and post-employment benefit
obligations are allocated to the Company based on basepensionable earnings.
The Company records a regulatory asset equal to its allocated share of Hydro
One's incremental net unfunded projected benefit
obligation for post-retirement and post-employment plans at each year end
based on annual actuarial reports. The regulatory
asset for the incremental net unfunded projected benefit obligation for
post-retirement and post-employment plans, in absence of
regulatory accounting, would be recognized in accumulated OCI. A regulatory
asset is recognized because management
considers it to be probable that post-retirement and post-employment benefit
costs will be recovered in the future through therate-setting process.
Post-retirement and post-employment benefits are recorded and included in
rates on an accrual basis. Costs are determined by
independent actuaries using the projected benefit method prorated on service
and based on assumptions that reflect
management's best estimates. Past service costs from plan amendments are
amortized to results of operations based on the
expected average remaining service period.
For post-retirement benefits, all actuarial gains or losses are deferred
using the "corridor" approach. The amount calculated
above the "corridor" is amortized to results of operations on a straight-line
basis over the expected average remaining service life
of active Hydro One employees in the plan and over the remaining life
expectancy of inactive Hydro One employees in the plan.
The post-retirement benefit obligation is remeasured to its fair value at
each year end based on an annual actuarial report, with
an offset to the associated regulatory asset, to the extent of the
remeasurement adjustment.
For post-employment obligations, the actuarial gains and losses that are
incurred during the year are recognized immediately to
results of operations. The post-employment benefit obligation is remeasured
to its fair value at each year end based on an
annual actuarial report, with an offset to the associated regulatory asset,
to the extent of the remeasurement adjustment.
All post-retirement and post-employment benefit costs are attributed to
labour costs and are either charged to results of
operations (OM&A costs) or capitalized as part of the cost of property, plant
and equipment for the service cost component and
to regulatory assets for all other components of the benefit costs,
consistent with their inclusion in OEB-approved rates.Stock-Based Compensation
Share Grant Plans
Hydro One measures share grant plans based on fair value of share grants as
estimated based on Hydro One Limited grant date
common share price. The costs are recognized in the financial statements
using the graded-vesting attribution method for share
grant plans that have both a performance condition and a service condition.
The Company records a regulatory asset equal to
the accrued costs of share grant plans recognized in each period. Costs are
transferred from the regulatory asset to labour costs
at the time the share grants vest and are issued, and are recovered in rates.
Forfeitures are recognized as they occur.
Society Restricted Share Unit (RSU) Plan

General Index of Financial Information

Notes to the financial statements

The Company measures its Society RSU plan based on fair value of share grants
as estimated based on Hydro One Limited's
grant date common share price. The costs are recognized over the vesting
period using the straight-line attribution method. The
Company records a regulatory asset equal to the accrued costs of the Society
RSU plan recognized in each period. Costs areHYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
11
transferred from the regulatory asset to labour costs at the time the share
grants vest and are issued, and are recovered in rates.
Forfeitures are recognized as they occur.
Long-term Incentive Plan (LTIP)
The Company measures the awards issued under Hydro One Limited's LTIP, at
fair value based on Hydro One Limited grant
date common share price. The related compensation expense is recognized over
the vesting period on a straight-line basis.
Forfeitures are recognized as they occur.
Loss Contingencies
Hydro One Remote Communities is involved in certain legal and environmental
matters that arise in the normal course of
business. In the preparation of its Financial Statements, management makes
judgments regarding the future outcome of
contingent events and records a loss for a contingency based on its best
estimate when it is determined that such loss is
probable and the amount of the loss can be reasonably estimated. Where the
loss amount is recoverable in future rates, a
regulatory asset is also recorded. When a range estimate for the probable
loss exists and no amount within the range is a better
estimate than any other amount, the Company records a loss at the minimum
amount within the range.
Management regularly reviews current information available to determine
whether recorded provisions should be adjusted and
whether new provisions are required. Estimating probable losses may require
analysis of multiple forecasts and scenarios that
often depend on judgments about potential actions by third parties, such as
federal, provincial and local courts or regulators.
Contingent liabilities are often resolved over long periods of time. Amounts
recorded in the Financial Statements may differ from
the actual outcome once the contingency is resolved. Such differences could
have a material impact on future results of
operations, financial position and cash flows of the Company.
Provisions are based upon current estimates and are subject to greater
uncertainty where the projection period is lengthy. A
significant upward or downward trend in the number of claims filed, the
nature of the alleged injuries, and the average cost of
resolving each claim could change the estimated provision, as could any
substantial adverse or favourable verdict at trial. A
federal or provincial legislative outcome or structured settlement could also
change the estimated liability. Legal fees areexpensed as incurred.
Environmental Liabilities
Environmental liabilities are recorded in respect of past contamination when
it is determined that future environmental
remediation expenditures are probable under existing statute or regulation
and the amount of the future expenditures can be
reasonably estimated. Hydro One Remote Communities records a liability for

General Index of Financial Information

Notes to the financial statements

the estimated future expenditures associated with
contaminated land assessment and remediation (LAR) based on the undiscounted
value of these estimated future expenditures.
As the Company anticipates that the future expenditures will continue to be
recoverable in future rates, an offsetting regulatory
asset has been recorded to reflect the future recovery of these environmental
expenditures from customers. Hydro One Remote
Communities reviews its estimates of future environmental expenditures
annually or more frequently if there are indications that
circumstances have changed. Estimate changes are accounted for prospectively.
3. NEW ACCOUNTING PRONOUNCEMENTS
The following tables present Accounting Standard Updates (ASUs) issued by the
Financial Accounting Standards Board that are
applicable to Hydro One Remote Communities:
Recently Adopted Accounting Guidance
Guidance Date issued Description Effective date Impact
ASU
2019-12
December
2019
The amendments simplify the accounting for income
taxes by removing certain exceptions to the general
principles and improving consistent application of
Topic 740 by clarifying and amending existing
guidance.
January 1, 2021 No impact upon adoption
ASU
2020-01
January 2020 The amendments clarify the interaction of the
accounting for equity securities under Topic 321,
investments under the equity method of accounting in
Topic 323 and the accounting for certain forward
contracts and purchased options accounted for under
Topic 815.
January 1, 2021 No impact upon adoption
ASU
2020-10
October 2020 The amendments are intended to improve the
Codification by ensuring the guidance required for an
entity to disclose information in the notes of financial
statements are codified in the disclosure sections to
reduce the likelihood of disclosure requirements being
missed.
January 1, 2021 No impact upon adoption
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
12
Recently Issued Accounting Guidance Not Yet Adopted
Guidance Date issued Description Effective date Anticipated impact
ASU
2020-06
August 2020 The update addresses the complexity associated with
applying GAAP for certain financial instruments with
characteristics of liabilities and equity. The amendments
reduce the number of accounting models for convertible

General Index of Financial Information

Notes to the financial statements

debt instruments and convertible preferred stock.
January 1 2022 No impact upon adoption
ASU
2021-05
July 2021 The amendments are intended to align lease classification requirements for lessors under Topic 842 with Topic 840's practice.
January 1, 2022 No impact upon adoption
ASU
2021-08
October 2021 The amendments address how to determine whether a contract liability is recognized by the acquirer in a business combination.
January 1, 2023 Under assessment
ASU
2021-10
November
2021
The update addresses the diversity on the recognition, measurement, presentation and disclosure of government assistance received by business entities.
January 1, 2022 Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 (thousands of dollars) 2021 2020
Depreciation of property, plant and equipment 3,058 2,834
Amortization of regulatory assets 1,435 870
Depreciation and amortization 4,493 3,704
Asset removal costs 342 361
4,835 4,065

5. FINANCING CHARGES

Year ended December 31 (thousands of dollars) 2021 2020
Interest on long-term debt 1,958 1,958
Amortization of hedging losses 19 18
Other 12 33
Interest capitalized on construction in progress (219) (173)
Interest income on inter-company demand facility (6) (23)
1,764 1,813

6. INCOME TAXES

As a rate regulated utility company, the Company recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated business. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred income tax expense (recovery). The Company's tax expense or recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable or refunded in future rates charged to customers. Thus, the Company's income tax expense or recovery differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate.HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020

General Index of Financial Information

Notes to the financial statements

13
The reconciliation between the statutory and the effective tax rates is
provided as follows:Year ended December 31 (thousands of dollars) 2021 2020
Loss before income tax expense - (3)
Income tax expense at statutory rate of 26.5% (2020 - 26.5%) - (1)
Increase (decrease) resulting from:
Net temporary differences recoverable in future rates charged to customers:
Non-capital losses 1,020 (225)
Depreciation and amortization in excess of capital cost allowance 404 271
Post-retirement and post-employment benefit expense in excess of cash
payments - 273RRRP variance account (1,063) 116
Environmental expenditures (380) (231)
Overheads capitalized for accounting but deducted for tax purposes (152) (152)
Pension contribution in excess of pension expense 174 (60)
Interest capitalized for accounting but deducted for tax purposes (58) (46)
Change in valuation allowance - -
Other 51 14
Net temporary differences (4) (40)
Prior year adjustments - 8
Other permanent differences 4 30
Total income tax expense (recovery) - (3)
The major components of income tax expense (recovery) are as follows:
Year ended December 31 (thousands of dollars) 2021 2020
Current income tax expense (recovery) - (3)
Deferred income tax expense - -
Total income tax expense (recovery) - (3)
Effective income tax rate - % 100.0 %
The following table presents a reconciliation of net income (loss) to net
income under the cost recovery model:
Year ended December 31 (thousands of dollars) 2021 2020
Net loss before income tax expense - (3)
Income tax recovery under cost-recovery model - (3)
Net income under cost-recovery model - -
Income tax expense - -
Net loss - -
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
14
Deferred Income Tax Assets and Liabilities
Deferred income tax assets and liabilities reflect the future tax
consequences attributable to temporary differences between the
tax bases and the financial statement carrying amounts of the assets and
liabilities including the carry forward amounts of tax
losses and tax credits. Deferred income tax assets and liabilities
attributable to the Company's regulated business are
recognized with a corresponding offset in deferred income tax regulatory
assets and liabilities to reflect the anticipated recovery
or repayment of these balances in the future electricity rates. At December
31, 2021 and 2020, deferred income tax assets and
liabilities consisted of the following:
As at December 31 (thousands of dollars) 2021 2020
Deferred income tax assets (liabilities)
Environmental expenditures 15,572 15,640
Depreciation and amortization in excess of capital cost allowance 2,685 3,448
Post-retirement and post-employment benefits expense in excess of cash

General Index of Financial Information

Notes to the financial statements

payments 6,631 6,623Regulatory amounts not recognized for tax (18,908)
(17,895)
Other 4,172 2,370
10,152 10,186
Less: valuation allowance (5,723) (5,693)
Net deferred income tax assets 4,429 4,493
During 2021 and 2020, there was no change in the rate applicable to deferred
tax assets and liabilities. The valuation allowance
for deferred tax assets as at December 31, 2021 was $5,723 thousand (2020 -
$5,693 thousand). The valuation allowance
primarily relates to temporary differences for non-depreciable assets and
loss carryforwards. As at December 31, 2021, the
Company had non-capital losses of $14,126 thousand, which will begin to
expire in 2036.7. ACCOUNTS RECEIVABLE
As at December 31, 2021 (thousands of dollars)
Current
accounts
receivable
Long-term
accounts
receivable Total
Accounts receivable - billed 5,026 6 5,032
Accounts receivable - unbilled 3,937 - 3,937
Accounts receivable, gross 8,963 6 8,969
Allowance for doubtful accounts (128) - (128)
Accounts receivable, net 8,835 6 8,841
As at December 31, 2020 (thousands of dollars)
Current
accounts
receivable
Long-term
accounts
receivable Total
Accounts receivable - billed 6,179 49 6,228
Accounts receivable - unbilled 2,920 - 2,920
Accounts receivable, gross 9,099 49 9,148
Allowance for doubtful accounts (324) - (324)
Accounts receivable, net 8,775 49 8,824
The following table shows the movements in the total allowance for doubtful
accounts for the years ended December 31, 2021and 2020:
Year ended December 31 (thousands of dollars) 2021 2020
Allowance for doubtful accounts - beginning (324) (119)
Write-offs 62 98
Adjustments to allowance for doubtful accounts 134 (303)
Allowance for doubtful accounts - ending (128) (324)
8. PROPERTY, PLANT AND EQUIPMENT
As at December 31, 2021 (thousands of dollars)
Property, Plant
and Equipment 1 Accumulated
Depreciation
Construction
in Progress Total
Generation 53,474 24,531 1,979 30,922
Distribution 13,182 3,124 831 10,889
Administration and service 13,221 3,915 679 9,985
79,877 31,570 3,489 51,796

General Index of Financial Information

Notes to the financial statements

1 Includes future use assets totalling $3,909 thousand.
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
15
As at December 31, 2020 (thousands of dollars)
Property, Plant
and Equipment 1 Accumulated
Depreciation
Construction
in Progress Total
Generation 51,077 23,445 2,842 30,474
Distribution 12,315 2,908 813 10,220
Administration and service 12,743 3,652 31 9,122
76,135 30,005 3,686 49,816
1 Includes future use assets totalling $4,534 thousand.
Financing charges capitalized on property, plant and equipment under
construction were $219 thousand in 2021 (2020 -$173 thousand).
9. REGULATORY ASSETS AND LIABILITIES
Regulatory assets and liabilities arise as a result of the rate-setting
process. Hydro One Remote Communities has recorded the
following regulatory assets and liabilities:
As at December 31 (thousands of dollars) 2021 2020
Regulatory assets:
Environmental 43,191 43,378
RRRP variance account 9,732 5,598
Stock-based compensation 432 467
Post-retirement and post-employment benefits - 569
COVID-19 emergency deferral - 120
Total regulatory assets 53,355 50,132
Less: current portion (3,172) (3,087)
50,183 47,045
Regulatory liabilities:
Deferred income tax regulatory liability 4,429 4,493
Post-retirement and post-employment benefits 481 -
COVID-19 emergency deferral 10 -
Total regulatory liabilities 4,920 4,493
Environmental
The Company records a liability for the estimated future expenditures
required to remediate environmental contamination. A
regulatory asset is recognized because management considers it to be probable
environmental expenditures will be recovered in
the future through the rate-setting process. The Company has recorded an
equivalent amount as a regulatory asset. In 2021, the
revaluation adjustment increased the environmental regulatory asset by $1,248
thousand (2020 - $10,153 thousand) to reflect
related changes in the Company's environmental liabilities. The environmental
regulatory asset is amortized to results of
operations based on the pattern of actual expenditures incurred and charged
to environmental liabilities. The OEB has the
discretion to examine and assess the prudency and the timing of recovery of
all of the Company's actual environmental
expenditures. In the absence of rate-regulated accounting, 2021 OM&A expenses
would have been higher by $1,248 thousand
(2020 - $10,153 thousand), and 2021 amortization expense would have been
lower by $1,435 thousand (2020 - $870 thousand).RRRP Variance Account

General Index of Financial Information

Notes to the financial statements

Hydro One Remote Communities receives RRRP amounts from the IESO. At December 31, 2021, the Company recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of cumulative RRRP amounts received. In 2021, RRRP amounts received were lower (2020 - higher) than amounts required to achieve breakeven net income, and as such, the regulatory asset was increased by $4,134 thousand (2020 -$491 thousand). In the absence of rate-regulated accounting, 2021 revenue would have been lower by $4,134 thousand (2020 -higher by $491 thousand).

Stock-Based Compensation

The Company recognizes costs associated with share grant plans and Society RSUs in a regulatory asset as management considers it probable that share grant plans' and Society RSU costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, there would be no material impact to operation, maintenance and administration expenses in 2021 and 2020. Share grant and Society RSU costs are transferred to labour costs at the time they vest and are issued, and are recovered in rates in accordance with recovery of these labour costs.HYDRO ONE REMOTE COMMUNITIES INC.

NOTES TO FINANCIAL STATEMENTS (continued)

For the years ended December 31, 2021 and 2020

16

Deferred Income Tax Regulatory Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized a regulatory liability that corresponds to deferred income taxes that flow through the rate-setting process. In the absence of rateregulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2021 income tax expense would have been higher by approximately $4 thousand (2020 - $40 thousand).Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the balance sheets with an incremental offset to the associated regulatory asset or regulatory liability, as the case may be. A regulatory asset or liability is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered or returned in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or liability as the case may be, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2021 OCI would have been higher by $1,050 thousand (2020 - $301thousand).

COVID-19 Emergency Deferral

On June 17, 2021, the OEB issued its Report: Regulatory Treatment of Impact Arising from the COVID-19 Emergency which

Corporation's name	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

General Index of Financial Information

Notes to the financial statements

outlines the OEB's final guidance on the rules and operation of the deferral account established for utilities to track the impacts arising from the COVID-19 pandemic. The OEB has determined that eligibility for recovery of most balances recorded in the account will be subject to a means test based on a utility's achieved regulatory return on equity (ROE). Based on management's assessment of the OEB's final guidance, no amounts related to the COVID-19 pandemic have been recognized as regulatory assets. The December 31, 2021 balance relates to over-recovered foregone revenues collected from ratepayers over the period from November 1, 2020 to April 30, 2021.

10. LONG-TERM DEBT

Long-term debt represents inter-company debt issued to Hydro One. The following table presents the Company's outstanding long-term debt at December 31, 2021 and 2020:

As at December 31 (thousands of dollars)	2021	2020
3.02% note due 2026	10,000	10,000
5.38% note due 2036	23,000	23,000
4.19% note due 2044	10,000	10,000
	43,000	43,000
Less: Deferred debt issuance costs	(142)	(150)
Less: Net unamortized debt premiums	(31)	(33)
Long-term debt	42,827	42,817

The Company did not issue or repay any long-term debt in 2021 and 2020.

Principal and Interest Payments

At December 31, 2021, future principal repayments, interest payments, and related weighted-average interest rates were asfollows:

Years	Long-Term Debt Principal Repayments (thousands of dollars)	Interest Payments (thousands of dollars)	Weighted-Average Interest Rate (%)
2022	-	1,958	-
2023	-	1,958	-
2024	-	1,958	-
2025	-	1,958	-
2026	-	1,809	-
	-	9,641	-
2027-2030	10,000	8,282	3.0
2031+	33,000	10,806	5.0
	43,000	28,729	4.6

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One Remote Communities classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into threelevels:

General Index of Financial Information

Notes to the financial statements

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Remote Communities has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.
Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability.
Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.
Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.Non-Derivative Financial Assets and Liabilities
At December 31, 2021 and 2020, the Company's carrying amounts of inter-company demand facility, accounts receivable, and accounts payable are representative of fair value due to the short-term nature of these instruments.Fair Value Hierarchy
The fair value hierarchy of financial assets and liabilities at December 31, 2021 and 2020 is as follows:As at December 31, 2021 (thousands of dollars)

	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt	42,827	52,123	-	52,123	-

As at December 31, 2020 (thousands of dollars)

	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt	42,817	55,701	-	55,701	-

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the sameremaining maturities.
There were no transfers between any of the fair value levels during the years ended December 31, 2021 or 2020.Risk Management
Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.Market Risk
Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates.
The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the one-month bankers' acceptance rate, plus 0.15%. The Company is not currently exposed to material commodity price risk ormaterial foreign exchange risk.
Credit Risk
Financial assets create a risk that a counterparty will fail to discharge an

obligation, causing a financial loss. At December 31,
2021 and 2020, there were no significant concentrations of credit risk with
respect to any class of financial assets. The
Company's revenue is earned from a broad base of customers. As a result,
Hydro One Remote Communities did not earn a
material amount of revenue from any single customer. At December 31, 2021 and
2020, there was no material accounts
receivable balance due from any single customer.
At December 31, 2021, the Company's allowance for doubtful accounts was $128
thousand (2020 - $324 thousand). The
allowance for doubtful accounts reflects the Company's CECL for all accounts
receivable balances, which are based on historical
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
18
overdue balances, customer payments and write-offs. At December 31, 2021,
approximately 14% (2020 - 28%) of the
Company's net accounts receivable were outstanding for more than 60 days. The
Company's credit risk for accounts receivable
is limited to the carrying amounts on its balance sheets.
Liquidity Risk
Liquidity risk refers to the Company's ability to meet its financial
obligations as they come due. Hydro One Remote Communities
meets its short-term liquidity requirements through the inter-company demand
facility with Hydro One and funds from operations.
The short-term liquidity available to the Company are expected to be
sufficient to fund normal operating requirements.
12. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS
Hydro One has a Pension Plan, a DC Plan, a supplementary pension plan
(Supplementary Plan), and post-retirement and postemploymentbenefit plans.
DC Plan
Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers
eligible management employees hired on or
after January 1, 2016, as well as management employees hired before January
1, 2016 who were not eligible to join the Pension
Plan as of September 30, 2015. Members of the DC Plan have an option to
contribute 4%, 5% or 6% of their pensionable
earnings, with matching contributions by Hydro One up to an annual
contribution limit. There is also a Supplementary DC Plan
that provides members of the DC Plan with employer contributions beyond the
limitations imposed by the Income Tax Act
(Canada) in the form of credits to a notional account. Company contributions
to the DC Plan for the year ended December 31,
2021 were $11 thousand (2020 - $10 thousand).
Pension Plan and Supplementary Plan
The Pension Plan is a defined benefit contributory plan which covers eligible
regular employees of Hydro One and its
subsidiaries. The Pension Plan provides benefits based on highest three-year
average pensionable earnings. For management
employees who commenced employment on or after January 1, 2004, and for the
Society of United Professionals (Society)-
represented staff hired after November 17, 2005, benefits are based on
highest five-year average pensionable earnings. After
retirement, pensions are indexed to inflation. Membership in the Pension Plan
was closed to management employees who were

General Index of Financial Information

Notes to the financial statements

not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible tojoin the DC Plan.
Hydro One and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2018 and filed on September 30, 2019. The new valuation is expected to be filed by no later than effective September 30, 2022, which may result in a change to the estimated contributions for 2022-2027.
Total Hydro One annual cash Pension Plan employer contributions for the Company in 2021 were $723 thousand (2020 - $711 thousand). Estimated Hydro One annual Pension Plan employer contributions allocated to the Company for the years 2022, 2023, 2024, 2025, 2026 and 2027 are approximately $1,053 thousand, $1,110 thousand, $1,156 thousand, $1,163 thousand, $1,190 thousand and $1,240 thousand respectively.
The Supplementary Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the Income Tax Act (Canada).
At December 31, 2021, the present value of Hydro One's projected pension benefit obligation was estimated to be $9,358 million (2020 - $9,763 million). The fair value of pension plan assets available for these benefits was $8,645 million (2020 - $8,103million).
Post-Retirement and Post-Employment Benefits
During the year ended December 31, 2021, Hydro One Remote Communities charged $873 thousand (2020 - $1,098 thousand) of post-retirement and post-employment benefit costs to operation, maintenances and administration expenses, and capitalized $456 thousand (2020 - $512 thousand) as part of the cost of property, plant and equipment. Benefits paid by the Company in 2021 were $258 thousand (2020 - $272 thousand). In addition, the incremental offset to decrease the associated post-retirement and post-employment benefits regulatory assets by $1,050 thousand (2020 - increase of $301 thousand) was recorded on the Company's balance sheet to reflect the expected regulatory inclusion of this amount in future rates, which would otherwise berecorded in OCI.
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
19
The Company presents its post-retirement and post-employment benefit liability on the balance sheets within the following lineitems:
As at December 31 (thousands of dollars) 2021 2020
Accrued liabilities 509 473
Post-retirement and post-employment benefit liability 17,882 17,898
18,391 18,371
13. ENVIRONMENTAL LIABILITIES
The following table shows the movements in environmental liabilities for the years ended December 31, 2021 and 2020:
Year ended December 31 (thousands of dollars) 2021 2020
Environmental liabilities - beginning 43,378 34,095
Expenditures (1,435) (870)
Revaluation adjustment 1,248 10,153
Environmental liabilities - ending 43,191 43,378

Less: current portion (3,064) (2,863)
40,127 40,515
The environmental liabilities are not discounted as the amount and timing of cash payments for the liabilities are not fixed orreliably determinable.
At December 31, 2021, the estimated future environmental expenditures were as follows:(thousands of dollars)
2022 3,064
2023 1,941
2024 2,510
2025 2,651
2026 1,144
Thereafter 31,881
43,191
The Company records a liability for the estimated future expenditures for LAR when it is determined that future environmental
remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can bereasonably estimated.
There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation
or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities,
the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures
will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's
environmental liabilities represent management's best estimates of the present value of costs, which is its undiscounted amount,
required to meet existing legislation or regulations.
As at December 31, 2021, the Company's best estimate of the total estimated future expenditures to complete its LAR program
was $43,191 thousand (2020 - $43,378 thousand). These expenditures are expected to be incurred over the period from 2021 to
2054. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2021 to
increase the LAR environmental liability by $1,248 thousand (2020 - $10,153 thousand).14. SHARE CAPITAL
Common Shares
The Company is authorized to issue an unlimited number of common shares. At December 31, 2021, the Company had 267
common shares issued and outstanding (2020 - 267).
Dividends
The Company does not pay dividends under its breakeven business model.
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
20
15. STOCK-BASED COMPENSATION
The following compensation plans were established by Hydro One Limited, however they represent components of
compensation costs of Hydro One and its subsidiaries, including Hydro One Remote Communities, in current and future periods.Share Grant Plans
Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers'
Union (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One
and Hydro One Limited entered into an intercompany agreement, such that Hydro

One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Remote Communities to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 38,541 Hydro One Limited common shares were granted under the PWU Share Grant Plan to employees of Hydro One Remote Communities.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore, the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 14,655 Hydro One Limited common shares were granted under the Society Share Grant Plan to employees of Hydro One Remote Communities.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Remote Communities of $1,091 thousand was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2021, 5,279 common shares of Hydro One Limited were issued under the Share Grant Plans (2020 - 5,387) to eligible employees of Hydro One Remote Communities. Total share based compensation recognized by Hydro One Remote Communities during 2021 was $63 thousand (2020 - $115 thousand) and was recorded as a regulatory asset.

General Index of Financial Information

Notes to the financial statements

For the years ended December 31, 2021 and 2020
21
A summary of Hydro One Remote Communities' share grant activity under the Share Grant Plans during years ended
December 31, 2021 and 2020 is presented below:
Share Grants Weighted-Average
Year ended December 31, 2021 (Number of common shares) Price
Share grants outstanding - beginning 34,984 $20.50
Vested and issued1 (5,279) -
Transfers2 2,614 -
Forfeited (1,897) $20.50
Share grants outstanding - ending 30,422 $20.50
1 In 2021, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.
2 Transfers relate to PWU employees transferred from Hydro One Networks to Hydro One Remote Communities during 2021. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.
Share Grants Weighted-Average
Year ended December 31, 2020 (Number of common shares) Price
Share grants outstanding - beginning 38,328 $20.50
Vested and issued1 (5,387) -
Transfers2 2,865 -
Forfeited (822) $20.50
Share grants outstanding - ending 34,984 $20.50
1 In 2020, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the Society Share Grant Plans. In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.
2 Transfers relate to PWU employees transferred from Hydro One Networks to Hydro One Remote Communities during 2020. These employees have been granted Hydro One Limited shares under the PWU Share Grant Plan in 2015.
Employee Share Ownership Plan
In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and nonrepresented
employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the
Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base
salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a
maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff
may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The
Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2021, Company
contributions made under the ESOP were $24 thousand (2020 - $22 thousand).
LTIP
Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives
are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based

General Index of Financial Information

Notes to the financial statements

awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.
The LTIP provides flexibility to award a range of vehicles, including restricted share units (RSUs), performance share units (PSUs), stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
22
PSUs and RSUs
During 2021 and 2020, the activity of PSU and RSU awards granted by Hydro One Limited that related to Hydro One RemoteCommunities were as follows:
PSUs RSUs
Year ended December 31 (number of units) 2021 2020 2021 2020
Units outstanding - beginning 3,284 6,065 2,319 2,377
Vested and issued1 (3,284) (2,711) (2,319) (12)
Forfeited - (70) - (46)
Units outstanding - ending - 3,284 - 2,319
1 In 2021, Hydro One Limited issued from treasury common shares to eligible Hydro One Remote Communities employees in accordance with provisions of the LTIP.
In accordance with the inter-company agreement between Hydro One and Hydro One Limited, Hydro One Remote Communities made payments to Hydro One for the common shares issued.
No awards were granted in 2021 or 2020. The compensation expense related to the PSU and RSU awards recognized by the Company during 2021 was $10 thousand (2020 - $100 thousand).
Society RSU Plan
As a result of the renewal of the Company's prior collective agreement with members of the Society, the Company provided equity compensation in the form of RSUs to certain eligible members. The equity compensation provides for the purchase of common shares of Hydro One Limited from the open market, effective March 1, 2021 in one equity grant vesting in equal portions over a two-year period. To be eligible, an employee must be an employee of the Company as of July 30, 2021, the date the plan was ratified by the Society; the grant date. The number of common shares issued to each eligible employee will be equal to 1.0% of such eligible employee's salary as at April 1, 2021, divided by $30.80, being the price of the common shares of Hydro One Limited at the grant date. Each RSU is entitled to accrue common share dividend equivalents in the form of additional RSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.
A summary of RSU awards activity under the Society RSU Plan during the years ended December 31, 2021 and 2020 ispresented below:
Year ended December 31 (number of RSUs) 2021 2020
RSUs outstanding - beginning - -
Granted 654 -

General Index of Financial Information

Notes to the financial statements

RSUs outstanding - ending 654 -
16. RELATED PARTY TRANSACTIONS
Hydro One Remote Communities is a subsidiary of Hydro One. Hydro One is owned
by Hydro One Limited. The Province is a
shareholder of Hydro One Limited with approximately 47.2% ownership at
December 31, 2021. The IESO is a related party to
Hydro One Remote Communities because it is controlled or significantly
influenced by the Ministry of Energy.
Year ended December 31 (thousands of dollars)
Related Party Transaction 2021 2020
IESO Supply of electricity to remote northern communities - amounts received1
35,223 35,223Amounts related to electricity rebates 5,060 7,735
Hydro One
Networks Inc.
Revenues related to the provision of services2 236 160
Cost of power 1,485 1,665
Costs expensed related to purchase of services2 2,848 3,158
Hydro One
Inc.
Interest income on inter-company demand facility 6 23
Interest expense on long-term debt 1,958 1,958
Costs expensed related to purchase of services2 55 23
Stock-based compensation costs 82 215
1 Consistent with the break even business model, the Company recognized
$39,357 thousand as RRRP revenue in 2021 (2020 - $34,732), with the difference
recorded in the regulatory asset RRRP variance account.
2 The Company has entered into various agreements with Hydro One and its
other subsidiaries related to the provision of corporate functions and
services, such as
legal, financial and human resources services, and operational services, such
as environmental, forestry, and line services.
Transactions with related parties are based on the requirements of the OEB's
Affiliate Relationships Code.HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
23
The amounts due to and from related parties are as follows:
As at December 31 (thousands of dollars) 2021 2020
Inter-company demand facility 2,540 (42)
Accounts receivable 470 767
Accrued interest 280 280
Long-term debt 42,969 42,967
17. STATEMENTS OF CASH FLOWS
The changes in non-cash balances related to operations consist of the
following:Year ended December 31 (thousands of dollars) 2021 2020
Accounts receivable (60) (1,337)
Fuel, materials and supplies (705) 498
Income taxes receivable 2 5
Long-term accounts receivable 43 73
Accounts payable 5,424 (6,120)
Accrued liabilities 3,476 (184)
Long-term accounts payable 4 82
Post-retirement and post-employment benefit liability 1,034 1,333
9,218 (5,650)
Supplementary Information
Year ended December 31 (thousands of dollars) 2021 2020

Net interest paid 1,958 1,958
As a result of using the cost recovery model applied to achieve after tax breakeven net income, any income tax expense paid arefully recovered.
18. CONTINGENCIES
Legal Proceedings
Hydro One Remote Communities is involved in various lawsuits, claims and regulatory proceedings in the normal course of
business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's
financial position, results of operations or cash flows.
Hydro One Remote Communities is a defendant in a lawsuit in which the plaintiff Wilderness North Air is seeking $16 million in
damages related to allegations of breach of contract following a competitive request for proposals for the supply of diesel fuel.
Hydro One Remote Communities is defending itself in the claim and has determined there is a reasonable possibility of liability to
the Company, and if liability is found, the estimated range of losses is between $50 thousand to $400 thousand.Transfer of Assets
The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to
some assets located on Reserves (as defined in the Indian Act (Canada)). Currently, the Ontario Electricity Financial Corporation
(OEFC) holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has
obtained all consents necessary to complete the transfer of title of these assets to itself. Hydro One cannot predict the aggregate
amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2021, Hydro One paid
approximately $2 million (2020 - $2 million) in respect of consents obtained. If Hydro One or the Company cannot obtain the
required consents, the OEFC will continue to hold these assets for an indefinite period of time. If Hydro One cannot reach a
satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited
number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have
a material adverse effect on Hydro One's and the Company's results of operations if Hydro One is not able to recover them infuture rate orders.
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020
24
19. COMMITMENTS
Operating Agreement
Hydro One Remote Communities is committed to an operating agreement related to a hydro facility owned by the Company to
pay annual performance payments for a period of 10 years. The operating agreement expires in 2022. During the year ended
December 31, 2021, the Company made payments totalling $150 thousand (2020 - $150 thousand). The following table presents
a summary of Hydro One Remote Communities' commitments under this agreement.
December 31, 2021 (thousands of dollars) Year 1 Year 2 Year 3 Year 4 Year 5
ThereafterOperating agreement 150 - - - - -
HYDRO ONE REMOTE COMMUNITIES INC.
NOTES TO FINANCIAL STATEMENTS (continued)
For the years ended December 31, 2021 and 2020

Corporation's name	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

General Index of Financial Information

Notes to the financial statements

25

–

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

Assets – lines 1000 to 2599

1062	8,835,000	1066	18,000	1122	3,240,000
1400	2,540,000	1480	3,172,000	1599	17,805,000
1740	66,656,000	1741	-27,655,000	1900	13,221,000
1901	-3,915,000	1920	3,489,000	2008	83,366,000
2009	-31,570,000	2420	50,203,000	2421	4,429,000
2589	54,632,000	2599	124,233,000		

Liabilities – lines 2600 to 3499

2620	18,190,000	2629	280,000	3139	18,470,000
3140	42,827,000	3320	17,982,000	3321	45,047,000
3450	105,856,000	3499	124,326,000		

Shareholder equity – lines 3500 to 3640

3500	5,000,000	3580	-442,000	3600	-4,651,000
3620	-93,000	3640	124,233,000		

Retained earnings – lines 3660 to 3849

3660	-4,651,976	3680	-167	3740	1,143
3849	-4,651,000				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

Description

Sequence number 0003 01

Other comprehensive income – lines 7000 to 7020

7008	19,140

Revenue – lines 8000 to 8299

8000	63,271,000	8089	63,271,000	8299	63,271,000

Cost of sales – lines 8300 to 8519

8408	34,481,000	8450	1,584,000	8518	36,065,000
8519	27,206,000				

Operating expenses – lines 8520 to 9369

8523	40,129	8623	364,869	8670	4,835,000
8714	1,764,000	9270	20,202,002	9367	27,206,000
9368	63,271,000				

Extraordinary items and taxes – lines 9970 to 9999

9990	167	9998	19,140	9999	18,973

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
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- 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			18,973	A
Add:				
Provision for income taxes – current	101	167		
Amortization of tangible assets	104	4,835,000		
Non-deduct ble meals and entertainment expenses	121	20,065		
Other reserves on lines 270 and 275 from Schedule 13	125	91,559		
Reserves from financial statements – balance at the end of the year	126	9,414,735		
Subtotal of additions		14,361,526	14,361,526	
Add:				
Financing fees deducted in books	216	8,462		

Other additions:

	1 Description 605	2 Amount 295
1	Non-deductible LTIP and share grants	75,650
2	PY true up of Ont ITC booked in OMA in CY GL	6,130
3	Lease Adjustment	810
4	Hedge Amortixation	19,140
	Total of column 2	101,730

Total of column 2	296	101,730		
Subtotal of other additions	199	110,192	110,192	D
Total additions	500	14,471,718	14,471,718	
Amount A **plus** line 500			14,490,691	B
Deduct:				
Capital cost allowance from Schedule 8	403	4,438,974		
Other reserves on line 280 from Schedule 13	413	100,535		
Reserves from financial statements – balance at the beginning of the year	414	12,257,120		
Contributions to deferred income plans from Schedule 15	417	258,261		
Subtotal of deductions		17,054,890	17,054,890	
Deduct:				
Non-taxable/deduct ble other comprehensive income items	347	19,140		

Other deductions:

	1 Description 705	2 Amount 395
1	Deductible removable costs	139,254
2	Deduction for capitalized amounts - see attached	792,706
3	OPEB capitalized	456,567
4	Environmental payments	1,435,000
5	CY Ontario ITC overaccrual adjustment	5,158
	Total of column 2	2,828,685

Total of column 2	396	2,828,685

Subtotal of other deductions	499	2,847,825 ▶	2,847,825	E
Total deductions	510	19,902,715 ▶	19,902,715	
Net income (loss) for income tax purposes (amount B **minus** line 510)			-5,412,024	C

Enter amount C on line 300 of the T2 return.

T2 SCH 1 E (19)

Canada

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Explanatory note

https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
8.0 NBV-UCC Temp Diff tab D30+D33

Description	Operator (Note)	Amount
D30: Capitalized interest		219,073 00
D33: Capitalized overhead	+	573,633 00
	+	
	+	
	Total	792,706 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 295 – Amount

Title Line 295 – Amount

Explanatory note

Non-deductible LTIP portion represents LTIP that is equity settled so no cash outflow. (1.3 LTIP tab)

Non-deductible share grants represents settlement of share grants during the year that hit the P&L but need to be reversed since not deductible for tax purposes.

Description	Operator (Note)	Amount
Non-deductible LTIP		5,826 00
Non-deductible Union share grants	+	69,824 00
	+	
	Total	75,650 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 295 – Amount

Title Line 295 – Amount

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Explanatory note

Current year Ontario ITC overaccrual adjustment

Description	Operator (Note)	Amount
CY Ontario co-op education tax credit accrued		9,000 00
CY Ontario Apprenticeship tax credit accrued	+	2,158 00
Actual Ontario CETC (Sch 550)	-	6,000 00
Actual Apprenticeship tax credit (Sch 552)	-	
	+	
	Total	5,158 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.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the federal Income Tax Act, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the T2 Corporation – Income Tax Guide.
- File this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the federal Income Tax Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			-5,412,024	1A
Net capital losses deducted in the year (enter as a positive amount)		1B		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)		1C		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)		1D		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		1E		
Employer deduction for non-qualified securities – Paragraph 110(1)(e)		1F		
Subtotal (total of amounts 1B to 1F)		►		1G
Subtotal (amount 1A **minus** amount 1G; if positive, enter "0"			-5,412,024	1H
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions				1I
Subtotal (amount 1H **minus** amount 1I)			-5,412,024	1J
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)				1K
Current-year non-capital loss (amount 1J **plus** amount 1K; if positive, enter "0") If amount 1L is negative, enter it on line 110 as a positive.			-5,412,024	1L

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		8,976,201	1M	
Non-capital loss expired **(note 1)**	100			
Non-capital losses at the beginning of the tax year (amount 1M **minus** line 100)	102	8,976,201	►	8,976,201
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary **(note 2)** corporation	105			
Current-year non-capital loss (from amount 1L)	110	5,412,024		
Subtotal (line 105 **plus** line 110)		5,412,024	►	5,412,024 1N
Subtotal (line 102 **plus** amount 1N)				14,388,225 1O

Note 1: A non-capital loss expires after **20 tax years** and an allowable business investment loss becomes a net capital loss after **10 tax years**.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Other adjustments (includes adjustments for an acquisition of control)	150			
Section 80 – Adjustments for forgiven amounts	140			
Subsection 111(10) – Adjustments for fuel tax rebate				
Non-capital losses of previous tax years applied in the current tax year Enter line 130 on line 331 of the T2 return.	130			
Current and previous years non-capital losses applied against current-year taxable dividends subject to Part IV tax **(note 3)**	135			
Subtotal (total of lines 150, 140, 130 and 135)				1P
Non-capital losses before any request for a carryback (amount 1O **minus** amount 1P)			14,388,225	1Q

Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901			
Second previous tax year to reduce taxable income	902			
Third previous tax year to reduce taxable income	903			
First previous tax year to reduce taxable dividends subject to Part IV tax	911			
Second previous tax year to reduce taxable dividends subject to Part IV tax	912			
Third previous tax year to reduce taxable dividends subject to Part IV tax	913			
Total of requests to carry back non-capital losses to previous tax years (total of lines 901 to 913)				1R
Closing balance of non-capital losses to be carried forward to future tax years (amount 1Q **minus** amount 1R)	180		14,388,225	

Note 3: Line 135 is the total of lines 330 and 335 from Schedule 3, Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200			
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205			
Subtotal (line 200 **plus** line 205)				2A
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Subtotal (line 250 **plus** line 240)				2B
Subtotal (amount 2A **minus** amount 2B)				2C
Current-year capital loss (from the calculation on Schedule 6, Summary of Dispositions of Capital Property)	210			
Unused non-capital losses from the 11th previous tax year **(note 4)**			2D	
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year **(note 5)**			2E	
Enter amount 2D or 2E, whichever is less	215			
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220			
Subtotal (amount 2C **plus** line 210 **plus** line 220)				2F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220.

Note 4: Determine the amount of the non-capital loss from the **11th previous tax year**, and enter the part of the non-capital loss that was not deducted in the **previous 11 years**.

Note 5: Enter the amount of the ABILs from the **11th previous tax year**. Enter the full amount on amount 2E.

Part 2 – Capital losses (continued)

Capital losses from previous tax years applied against the current-year net capital gain **(note 6)** ..... **225** ______

Capital losses before any request for a carryback (amount 2F **minus** line 225) ______ 2G

Request to carry back capital loss to (note 7):

	Capital gain (100%)		Amount carried back (100%)	
First previous tax year		951		
Second previous tax year		952		
Third previous tax year		953		
Subtotal (total of lines 951 to 953)			▶	2H

Closing balance of capital losses to be carried forward to future tax years (amount 2G **minus** amount 2H) **(note 8)** **280** ______

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current tax year, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **divide** this amount by 2. The result represents the 50% inclusion rate.

Note 8: Capital losses can be carried forward indefinitely.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

	Line	Amount		Total	
Farm losses at the end of the previous tax year			3A		
Farm loss expired **(note 9)**	300				
Farm losses at the beginning of the tax year (amount 3A **minus** line 300)	302		▶		
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305				
Current-year farm loss (amount 1K in Part 1)	310				
Subtotal (line 305 **plus** line 310)			▶		3B
Subtotal (line 302 **plus** amount 3B)					3C
Other adjustments (includes adjustments for an acquisition of control)	350				
Section 80 – Adjustments for forgiven amounts	340				
Farm losses of previous tax years applied in the current tax year Enter line 330 on line 334 of the T2 Return.	330				
Current and previous years farm losses applied against current-year taxable dividends subject to Part IV tax **(note 10)**	335				
Subtotal (total of lines 350, 340, 330 and 335)			▶		3D
Farm losses before any request for a carryback (amount 3C **minus** amount 3D)					3E

Request to carry back farm loss to:

	Line	Amount		Total	
First previous tax year to reduce taxable income	921				
Second previous tax year to reduce taxable income	922				
Third previous tax year to reduce taxable income	923				
First previous tax year to reduce taxable dividends subject to Part IV tax	931				
Second previous tax year to reduce taxable dividends subject to Part IV tax	932				
Third previous tax year to reduce taxable dividends subject to Part IV tax	933				
Subtotal (total of lines 921 to 933)			▶		3F

Closing balance of farm losses to be carried forward to future tax years (amount 3E **minus** amount 3F) **380** ______

Note 9: A farm loss expires after **20 tax years**.

Note 10: Line 335 is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			485		
(line 485 ______ – $2,500) **divided** by 2		4A			
Amount 4A or $ 15,000 , whichever is less		▶		4B	
			2,500	4C	
Subtotal (amount 4B **plus** amount 4C)			2,500 ▶	2,500	4D
Current-year restricted farm loss (line 485 **minus** amount 4D)					4E

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year				4F	
Restricted farm loss expired **(note 11)**	400				
Restricted farm losses at the beginning of the tax year (amount 4F **minus** line 400)	402		▶		
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	405				
Current-year restricted farm loss (from amount 4E)	410				
Enter line 410 on line 233 of Schedule 1, Net Income (Loss) for Income Tax Purposes.					
Subtotal (line 405 **plus** line 410)			▶		4G
Subtotal (line 402 **plus** amount 4G)					4H
Restricted farm losses from previous tax years applied against current farming income	430				
Enter line 430 on line 333 of the T2 return.					
Section 80 – Adjustments for forgiven amounts	440				
Other adjustments	450				
Subtotal (total of lines 430 to 450)			▶		4I
Restricted farm losses before any request for a carryback (amount 4H **minus** amount 4I)					4J

Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	941				
Second previous tax year to reduce farming income	942				
Third previous tax year to reduce farming income	943				
Subtotal (total of lines 941 to 943)			▶		4K
Closing balance of restricted farm losses to be carried forward to future tax years (amount 4J **minus** amount 4K)			480		

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 11: A restricted farm loss expires after **20 tax years**.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year		5A		
Listed personal property loss expired **(note 12)**	500			
Listed personal property losses at the beginning of the tax year (amount 5A **minus** line 500)	502	▶		
Current-year listed personal property loss (from Schedule 6)			510	
Subtotal (line 502 **plus** line 510)				5B
Listed personal property losses from previous tax years applied against listed personal property gains	530			
Enter line 530 on line 655 of Schedule 6.				
Other adjustments	550			
Subtotal (line 530 **plus** line 550)		▶		5C
Listed personal property losses remaining before any request for a carryback (amount 5B **minus** amount 5C)				5D

Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961			
Second previous tax year to reduce listed personal property gains	962			
Third previous tax year to reduce listed personal property gains	963			
Subtotal (total of lines 961 to 963)		▶		5E
Closing balance of listed personal property losses to be carried forward to future tax years (amount 5D **minus** amount 5E)			580	

Note 12: A listed personal property loss expires after **7 tax years**.

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership account number	Tax year ending YYYY/MM/DD	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6)
600	602	604	606	608		620
1.						

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership account number	Tax year ending YYYY/MM/DD	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6)
630	632	634	636	638		650
1.						

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership account number	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary	Current-year limited partnership losses (from line 620)	Limited partnership losses applied in the current year (must be equal to or less than line 650)	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5)
660	662	664	670	675	680
1.					

Total (enter this amount on line 335 of the T2 return)

Note
If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), tick the box . . . . 190 Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note
This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce Taxable income	Applied to reduce Part IV tax	Balance at end of year
Current	N/A	5,412,024			N/A		5,412,024
1st preceding taxation year 2020-12-31	642,612	N/A		N/A			642,612
2nd preceding taxation year 2019-12-31	2,789,810	N/A		N/A			2,789,810
3rd preceding taxation year 2018-12-31	5,039,814	N/A		N/A			5,039,814
4th preceding taxation year 2017-12-31	306,376	N/A		N/A			306,376
5th preceding taxation year 2016-12-31	197,589	N/A		N/A			197,589
6th preceding taxation year 2015-12-31		N/A		N/A			
7th preceding taxation year 2015-11-04		N/A		N/A			
8th preceding taxation year 2015-10-31		N/A		N/A			
9th preceding taxation year 2014-12-31		N/A		N/A			
10th preceding taxation year 2013-12-31		N/A		N/A			
11th preceding taxation year 2012-12-31		N/A		N/A			
12th preceding taxation year 2011-12-31		N/A		N/A			
13th preceding taxation year 2010-12-31		N/A		N/A			
14th preceding taxation year 2009-12-31		N/A		N/A			
15th preceding taxation year 2008-12-31		N/A		N/A			
16th preceding taxation year 2007-12-31		N/A		N/A			
17th preceding taxation year 2006-12-31		N/A		N/A			
18th preceding taxation year 2005-12-31		N/A		N/A			
19th preceding taxation year 2004-12-31		N/A		N/A			
20th preceding taxation year 2003-12-31		N/A		N/A			*
Total	8,976,201	5,412,024					14,388,225

* **This balance expires this year and will not be available next year.**

Canada Revenue Agency / Agence du revenu du Canada

Tax Calculation Supplementary – Corporations

Schedule 5

Corporation's name	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- Use this schedule if any of the following apply to your corporation during the tax year:
  - it 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)
  - it is claiming provincial or territorial tax credits or rebates (see Part 2)
  - it has to pay taxes, other than income tax, for Newfoundland and Labrador or Ontario (see Part 2)
- All legislative references are to the federal Income Tax Regulations (the 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 Note 1		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 Note 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		

Note 1: **Permanent establishment** is defined in subsection 400(2).
Note 2: For corporations other than those descr bed 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	517		
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal (line 278 **plus** line 280)		517	517	5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)			517	5I
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	6,000		
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)		6,000	6,000	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	-5,483	

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 -5,483

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.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

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 proper ies (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		14,554,652	432,315	432,315				0	14,986,967
2.	2		66,708						0	66,708
3.	3		575						0	575
4.	6		3,751,440	653,477	653,477				0	4,404,917
5.	8		635,462	25,815	25,815				0	661,277
6.	10		134,879						0	134,879
7.	17		15,289,776	2,022,829	2,022,829				0	17,312,605
8.	43.1		203,422						0	203,422
9.	45		113						0	113
10.	47		7,595,242	1,338,043	1,338,043				0	8,933,285
11.	13	[redacted]	25,090						0	25,090
12.	13	[redacted]	34,144						0	34,144
13.	13	[redacted]	2,924						0	2,924
14.	14.1		12,447,080						0	12,447,080
15.	50		3,437						0	3,437
16.	46			3,814	3,814				0	3,814
		Totals	54,744,944	4,476,293	4,476,293					59,221,237

	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			432,315	216,158		4	0	0	608,125	14,378,842
2.	2						6	0	0	4,002	62,706
3.	3						5	0	0	29	546
4.	6			653,477	326,739		10	0	0	473,166	3,931,751
5.	8			25,815	12,908		20	0	0	134,837	526,440
6.	10						30	0	0	40,464	94,415
7.	17			2,022,829	1,011,415		8	0	0	1,465,922	15,846,683
8.	43.1						30	0	0	61,027	142,395
9.	45						45	0	0	51	62
10.	47			1,338,043	669,022		8	0	0	768,185	8,165,100
11.	13	[redacted]					NA	0	0	4,233	20,857
12.	13	[redacted]					NA	0	0	1,107	33,037
13.	13	[redacted]					NA	0	0	2,924	
14.	14.1						5	0	0	871,296	11,575,784
15.	50						55	0	0	1,890	1,547
16.	46			3,814	1,907		30	0	0	1,716	2,098
		Totals		4,476,293	2,238,149					4,438,974	54,782,263

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 Regula ion 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, net of any government assistance received or entitled to be received in the year from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in he 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 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 hat 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 and 12 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 UCC (column 9). Items that increase the UCC include amounts transferred under sec ion 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the year for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See the T2 Corporation Income Tax Guide for other examples of adjustments and transfers to include in column 5.
Also include 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 acquired by the transferor at least 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

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)

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 include 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 acquired by the transferor less than 364 days before the end of your tax year and continuously owned by he transferor until it was acquired by you.

Note 7. For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to he 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 me hod, 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 acquisi ion, 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 he replacement property rules apply, unless certain conditions are met

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.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		4,476,293		
Additions for tax purposes – Schedule 8 leasehold improvements	+			
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+			
Other (specify):				
Current year capitalized allocations (Interest, OPEB, LTIP, etc.)	+	1,547,100		
Capital items deducted for book purposes	+	-202,879		
CIP decrease (CY $3,489K - PY 3,686K)	+	-197,000		
Future Use Asset increase (CY$3,949K - PY$4,534 K)	+	-585,000		
Total additions per books	=	5,038,514	▶	5,038,514
Proceeds up to original cost – Schedule 8 regular classes				
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):				
Reg asset amortn included in depreciation add-back on S1	+	-1,434,644		
Asset removal costs included in depn add-back on S1	+	-342,133		
Rounding	+	291		
Total proceeds per books	=	-1,776,486	▶ –	-1,776,486
Depreciation and amortization per accounts – Schedule 1			–	4,835,000
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	
Net change per tax return			=	1,980,000

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		51,796,000
Opening net book value	–	49,816,000
Net change per financial statements	=	1,980,000

If the amounts from the tax return and the financial statements differ, explain why below.

Attached Schedule with Total

Other – Amount

Title Other – Amount

Explanatory note

These are items that are capitalized for accounting but deducted for tax and hence not in tax additions and as a result is a reconciling item.

Description	Operator (Note)	Amount	
Capitalized interest		219,073	00
Capitalized pension	+	258,262	00
Capitalized OPEB	+	456,567	00
Capitalized overhead	+	573,633	00
Capitalized union share grants	+	36,518	00
Capitalized LTIP	+	3,047	00
	+		
	+		
	Total	1,547,100	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Other – Amount

Title Other – Amount

Description	Operator (Note)	Amount
Removal costs		-342,133 00
Less: deductible removal costs	+	139,254 00
	+	
	+	
	Total	-202,879 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.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- 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.	Hydro One Limited	CA	[redacted]	3					
2.	Hydro One Inc.	CA	[redacted]	1					
3.	2486267 Ontario Inc.	CA	[redacted]	3					
4.	2486268 Ontario Inc.	CA	[redacted]	3					
5.	Hydro One Networks Inc.	CA	[redacted]	3					
6.	Acronym Solutions Inc.	CA	[redacted]	3					
7.	Hydro One Telecom Link Limited	CA	[redacted]	3					
8.	Municipal Billing Services Inc.	CA	[redacted]	3					
9.	Hydro One Lake Erie Link Managem	CA	[redacted]	3					
10.	1938454 Ontario Inc.	CA	[redacted]	3					
11.	1943404 Ontario Inc.	CA	[redacted]	3					
12.	Hydro One Indigenous Partnerships	CA	[redacted]	3					
13.	Norfolk Energy Inc.	CA	[redacted]	3					
14.	Norfolk Power Distribution Inc.	CA	[redacted]	3					
15.	Haldimand County Energy Inc.	CA	[redacted]	3					
16.	Haldimand County Hydro Inc.	CA	[redacted]	3					
17.	Woodstock Hydro Services Inc.	CA	[redacted]	3					
18.	Hydro One Sault Ste. Marie Holding	CA	[redacted]	3					
19.	Hydro One Sault Ste. Marie Inc.	CA	[redacted]	3					
20.	Hydro One Sault Ste. Marie Holding	CA	[redacted]	3					
21.	1228185 Ontario Inc.	CA	[redacted]	3					
22.	Hydro One East-West Tie Inc.	CA	[redacted]	3					
23.	1937680 Ontario Inc.	CA	[redacted]	3					
24.	1937681 Ontario Inc.	CA	[redacted]	3					
25.	2587264 Ontario Inc.	CA	[redacted]	3					
26.	Hydro One Holdings Limited	CA	[redacted]	3					
27.	2587265 Ontario Inc.	CA	[redacted]	3					
28.	Hydro One Investment Holdings In	CA	[redacted]	3					
29.	Orillia Power Distribution Corporatic	CA	[redacted]	3					
30.	2835785 Ontario Inc.	CA	[redacted]	3					
31.	Aux Energy Inc.	CA	[redacted]	3					
32.	Hydro One Broadband Solutions In	CA	[redacted]	3					
33.	Olympus Holding Corp.	US	NR	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- 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	☐	110	115			120
Reserve for undelivered goods and services not rendered	X	130 91,559	135	8,976		140 100,535
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 91,559	275	8,976		280 100,535

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	OPEB Liability	18,370,576		1,071,889	1,050,597	18,391,868
2	Reg asset re OPEB Liability	-569,115		1,050,597		481,482
3	Environmental Liabilities	43,378,635			187,244	43,191,391
4	Reg asset re Environ. Liabilities	-43,378,635		187,244		-43,191,391
5	Bonus accrual - 413741					
6	Reg Asset	-5,718,139			4,013,599	-9,731,738
7	Reg Asset Tax Rule changes					
8	LTIP Accrual	82,239		90,349		172,588
9						
	Reserves from Part 2 of Schedule 13	91,559		8,976		100,535
	Totals	12,257,120		2,409,055	5,251,440	9,414,735

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
OPEB Expense/Payments		860,775 00
OPEB Capitalization	+	211,114 00
	+	
	Total	1,071,889 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – Financial statement reserves – Federal – Add

Title Part 1 – Financial statement reserves – Federal – Add

Explanatory note

Taxprep Jumpcode 13S Line 2

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
13.5 Regulatory tab F147 to F150

Description	Operator (Note)	Amount	
F147 100255040 - Reg Asset - OPRB - Health & Dental Obligation		947,043	00
F148 100255050 - Reg Asset - OPEB - LTD Obligation	+		
F149 100255060 - Reg Asset - OPRB SPP Obligation	+	-103,554	00
F150 Pencil adjustment re: non-recognition of SPS asset	+		
	+		
	Total	843,489	00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – Financial statement reserves – Federal – Deduct

Title Part 1 – Financial statement reserves – Federal – Deduct

Description	Operator (Note)	Amount	
Change in OPEB Valuation		1,050,597	00
	+		
	Total	1,050,597	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.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Networks Inc.	8th Floor South Tower 483 Bay Street Toronto ON CA M5G 2P5			790,413		
2	Hydro One Inc	8th Floor South Tower 483 Bay Street Toronto ON CA M5G 2P5			55,206		

T2 SCH 14 (99)

Canada

Canada Revenue Agency Agence du revenu du Canada

Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- 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	623,130	1059104			

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	623,130	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	364,869	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")	258,261	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

Canada Revenue Agency Agence du revenu du Canada

Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year
  - to claim a deduction against Part I tax payable
  - to claim a refund of credit earned during the current tax year
  - to claim a carryforward of credit from previous tax years
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as descr bed under subsections 87(1) and 88(1)
  - to request a credit carryback to one or more previous years
  - if you are subject to a recapture of ITC
  - if you are claiming:
    - the **Ontario Research and Development Tax Credit**
    - the **Ontario Innovation Tax Credit**
- Unless otherwise stated, all legislative references are to the federal Income Tax Act and Income Tax Regulations.
- The ITC is eligible for a three-year carryback (if not deduct ble in the year earned). It is also eligible for a twenty-year carryforward.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that currently earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule)
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, Scientific Research and Experimental Development (SR&ED) Expenditures Claim
  - pre-production mining expenditures (Part 18)
    - You can no longer claim the ITC for the pre-production mining expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you made the investment.
  - apprenticeship job creation expenditures (Parts 19 to 21)
  - child care spaces expenditures (Parts 22 to 26)
    - Expenditures related to child care spaces incurred after March 21, 2017, no longer qualify for the ITC. However, if you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 remain eligible for the credit.
- File this schedule with the T2 Corporation Income Tax Return. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, T2 Corporation – Income Tax Guide and read Information Circular IC78-4, Investment Tax Credit Rates, and its related Special Release.
- For more information on SR&ED, see Guide T4088, Scientific Research and Experimental Development (SR&ED) Expenditures Claim – Guide to Form T661.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property at the time it files the income tax return for the year in which the property was acquired.
- An ITC deducted in a tax year for a depreciable property, other than a depreciable property deduct ble under paragraph 37(1)(b), reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures.
- Expenditures for apprenticeship or child care space for an ITC must be identified by the claimant on Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners.
  For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 Forms).
- For tax purposes**,** Canada includes the **exclusive economic zone of Canada** as defined in the Oceans Act (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).

Detailed information (continued)

- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012, unless transitional measures were granted*. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as descr bed in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescr bed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15% rate.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada	15 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred expenditures after March 18, 2007, and before March 22, 2017 (or before 2020 if you entered into a written agreement before March 22, 2017) for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . **101** Yes ☐ No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if both of the following conditions are met:

- one corporation is associated with another corporation only because one or more persons own shares of the capital stock of both corporations
- one of the corporations has at least one shareholder who is not common to both corporations

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to one of the following:

a) one or more persons exempt from Part I tax under section 149
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority
c) any combination of persons referred to in a) or b) above

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . **102** Yes ☐ No ☒

If **yes**, complete Schedule 125, Income Statement Information, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED* . . . . ________ x 80 % = **103** ________
Enter on line 350 of Part 8.

* Enter only contr butions not already included on Form T661.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**
			Total of investments for qualified property and qualified resource property	A1

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year				B1
Credit deemed as a remittance of co-op corporations	210			
Credit expired	215			
Subtotal (line 210 **plus** line 215)				C1
ITC at the beginning of the tax year (amount B1 **minus** amount C1)			220	
Credit transferred on an amalgamation or the wind-up of a subsidiary	230			
ITC from repayment of assistance	235			
Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part from amount A1 in Part 4) ______ x 10 % =	240			
Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part from amount A1 in Part 4) ______ x 5 % =	242			
Credit allocated from a partnership	250			
Subtotal (total of lines 230 to 250)				D1
Total credit available (line 220 **plus** amount D1)				E1
Credit deducted from Part I tax	260			
Credit carried back to previous years (amount H1 in Part 6)		a		
Credit transferred to offset Part VII tax liability	280			
Subtotal (total of line 260, amount a, and line 280)				F1
Credit balance before refund (amount E1 **minus** amount F1)				G1
Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7)			310	
ITC closing balance of investments from qualified property and qualified resource property (amount G1 **minus** line 310)			320	

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day			
1st previous tax year				Credit to be applied	901	
2nd previous tax year				Credit to be applied	902	
3rd previous tax year				Credit to be applied	903	
				Total of lines 901 to 903 Enter at amount a in Part 5.		H1

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 in Part 5)	I1
Credit balance before refund (from amount G1 in Part 5)	J1
Refund (40 % of amount I1 or J1, whichever is less)	K1

Enter amount K1 or a lesser amount on line 310 in Part 5 (also enter on line 780 of the T2 return if you do not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures (from line 559 on Form T661)				
Contributions to agricultural organizations for SR&ED				
Deduct: Government assistance, non-government assistance, or contract payment				
Subtotal				
x	80 %			
Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)*		+		
Qualified SR&ED expenditures (line 559 on Form T661 **plus** line 103 in Part 3)*			350	
Repayments made in the year (from line 560 on Form T661)			370	
Total qualified SR&ED expenditures (line 350 **plus** line 370)			380	

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if you are a CCPC.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if both of the following apply:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation
- one of the corporations has at least one shareholder who is not common to both corporations

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . 385 Yes ☐ No ☐

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete lines 390 and 398.
If you answered **yes**, complete Schedule 49, Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Expenditure Limit, to determine the amounts for associated corporations.

Enter your taxable income for the previous tax year* (prior to any loss carrybacks applied)	390	
Enter your taxable capital employed in Canada for the previous tax year **minus** $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million	398	

* If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone (not associated) corporation		$ 8,000,000	
Taxable income for the previous tax year (line 390 in Part 9) or $500,000, whichever is more	x 10 =		A2
Excess ($8,000,000 **minus** amount A2; if negative, enter "0")			B2
$ 40,000,000 **minus** line 398 in Part 9	b		
Amount b **divided** by $ 40,000,000			C2
For tax years ending before March 19, 2019 Amount B2 **multiplied** by amount C2			D2
For tax years ending after March 18, 2019 **multiplied** by amount C2			E2
Expenditure limit for the stand-alone corporation (amount D2 or amount E2, whichever applies)*			F2
For an associated corporation: If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49*	400		G2

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount F2 or G2 ______ x Number of days in the tax year 365 / 365 = ... ______ H2

Your SR&ED expenditure limit for the year (enter amount F2, G2, or H2, whichever applies) . . . . . 410 ______

* Amount F2 or G2 cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Qualified SR&ED expenditures (from line 350 in Part 8) or the expenditure limit (from line 410 in Part 10), whichever is less*	420		x 35 % =		I2
Line 350 **minus** line 410 (if negative, enter "0")	430		x 15 % =		J2

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) .....

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure for a CCPC**	460		x 35 % =		c
Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred before 2015	480		x 20 % =		d
Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred after 2014	490		x 15 % =		e
			Subtotal (total of amounts c to e)	▶	K2

Current-year SR&ED ITC (total of amounts I2 to K2; enter on line 540 in Part 12) L2

* For corporations that are not CCPCs, enter "0" for amount I2.

** If you were a Canadian-controlled private corporation (CCPC), this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **Additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				M2
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)			▶	N2
ITC at the beginning of the tax year (amount M2 **minus** amount N2)			520	
Credit transferred on an amalgamation or the wind-up of a subsidiary	530			
Total current-year credit (from amount L2 in Part 11)	540			
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)			▶	O2
Total credit available (line 520 **plus** amount O2)				P2
Credit deducted from Part I tax	560			
Credit carried back to previous years (amount S2 in Part 13)		f		
Credit transferred to offset Part VII tax liability	580			
Subtotal (total of line 560, amount f, and line 580)			▶	Q2
Credit balance before refund (amount P2 **minus** amount Q2)				R2
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED (amount R2 **minus** line 610)			620	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	

Total of lines 911 to 913 ______ S2
Enter at amount f in Part 12.

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined on line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 Yes [ ] No [X]

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount K2 in Part 11) . . . . . ______ g

Refundable credits (amount g or amount R2 in Part 12, whichever is less)* . . . . . ______ T2

Amount T2 or amount I2 in Part 11, whichever is less . . . . . ______ U2

Net amount (amount T2 **minus** amount U2; if negative, enter "0") . . . . . ______ V2

Amount V2 **multiplied** by 40 % . . . . . ______ W2

Amount U2 . . . . . ______ X2

Refund of ITC (amount W2 **plus** amount X2 – enter this, or a lesser amount, on line 610 in Part 12) . . . . . ______ Y2
Enter the total of line 310 in Part 5 and line 610 in Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation, as defined in subsection 127.1(2), this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y2.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this part only if you are a CCPC that is not a qualifying or excluded corporation as determined on line 101 in Part 2.

Credit balance before refund (amount R2 in Part 12) . . . . . ______ Z2

Refund of ITC (amount Z2 or amount I2 in Part 11, whichever is less) . . . . . ______ AA2
Enter amount AA2, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as descr bed in the **note** above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less

Subtotal Enter at amount C3 in Part 17. ____ A3

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at amount B3.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less

Subtotal (total of column F) Enter at amount D3 in Part 17. ____ B3

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED (continued)

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC **760** ______
Enter at amount E3 in Part 17.

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount A3 in Part 16		C3
Recaptured ITC from calculation 2, amount B3 in Part 16		D3
Recaptured ITC from calculation 3, line 760 in Part 16		E3
Total recapture of SR&ED investment tax credit (total of amounts C3 to E3) Enter at amount A8 in Part 27.		F3

Pre-Production Mining

Part 18 – Account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year				A4
Credit deemed as a remittance of co-op corporations	**841**			
Credit expired	**845**			
Subtotal (line 841 **plus** line 845)			►	B4
ITC at the beginning of the tax year (amount A4 **minus** amount B4)			**850**	
Credit transferred on an amalgamation or the wind-up of a subsidiary			**860**	
Total credit available (line 850 **plus** line 860)				C4
Amount of unused credit carried forward from previous years and applied to reduce Part I tax payable in the current year			**885**	
ITC closing balance from pre-production mining expenditures (amount C4 **minus** line 885)			**890**	

Apprenticeship Job Creation

Part 19 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . **611** Yes X No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages* **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**
1	[redacted]	[redacted]	4,911	491	491
2	[redacted]	[redacted]	32,576	3,258	2,000
				Total current-year credit (total of column E) Enter on line 640 in Part 20.	2,491 A5

* Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 20 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year			14,795	B5
Credit deemed as a remittance of co-op corporations	**612**			
Credit expired after 20 tax years	**615**			
Subtotal (line 612 **plus** line 615)				C5
ITC at the beginning of the tax year (amount B5 **minus** amount C5)		**625**	14,795	
Credit transferred on an amalgamation or the wind-up of a subsidiary	**630**			
ITC from repayment of assistance	**635**			
Total current-year credit (amount A5 in Part 19)	**640**	2,491		
Credit allocated from a partnership	**655**			
Subtotal (total of lines 630 to 655)		2,491	2,491	D5
Total credit available (line 625 **plus** amount D5)			17,286	E5
Credit deducted from Part I tax	**660**			
Credit carried back to previous years (amount G5 in Part 21)		h		
Subtotal (line 660 **plus** amount h)				F5
ITC closing balance from apprenticeship job creation expenditures (amount E5 **minus** amount F5)		**690**	17,286	

Part 21 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	**931**	
2nd previous tax year				Credit to be applied	**932**	
3rd previous tax year				Credit to be applied	**933**	
				Total of lines 931 to 933 Enter at amount h in Part 20.		G5

Child Care Spaces

Part 22 – Eligible child care spaces expenditures

Enter the elig ble expenditures that you incurred after March 18, 2007, and before March 22, 2017,* to create licensed child care spaces for the children of the employees and, potentially, for other children. You cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property)
- the specified child care start-up expenditures

Properties should be acquired and expenditures should be incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	Capital cost allowance class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year (total of column 695)	715		
Specified child care start-up expenditures from the current tax year	705		
Total gross eligible expenditures for child care spaces (line 715 **plus** line 705)			A6
Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to in amount A6	725		
Excess (amount A6 **minus** line 725) (if negative, enter "0")			B6
Repayments by the corporation of government and non-government assistance	735		
Total eligible expenditures for child care spaces (amount B6 **plus** line 735)	745		

* If you entered into a written agreement before March 22, 2017, eligible expenditures incurred before 2020 will remain eligible for the credit.

Part 23 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745 in Part 22)			x	25 %	=	C6
Number of child care spaces created in the year	755		x	$ 10,000	=	D6
ITC from child care spaces expenditures (amount C6 or D6, whichever is less)						E6

Part 24 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F6
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			►	G6
ITC at the beginning of the tax year (amount F6 **minus** amount G6)			775	
Credit transferred on an amalgamation or the wind-up of a subsidiary	777			
Total current-year credit (amount E6 in Part 23)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			►	H6
Total credit available (line 775 **plus** amount H6)				I6
Credit deducted from Part I tax	785			
Credit carried back to previous years (amount K6 in Part 25)			i	
Subtotal (line 785 **plus** amount i)			►	J6
ITC closing balance from child care spaces expenditures (amount I6 **minus** amount J6)			790	

Part 25 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2020-12-31	Credit to be applied	941	
2nd previous tax year	2019-12-31	Credit to be applied	942	
3rd previous tax year	2018-12-31	Credit to be applied	943	

Total of lines 941 to 943 — K6
Enter at amount i in Part 24.

Recapture – Child Care Spaces

Part 26 – Recapture of ITC for corporations and partnerships – Child care spaces

The ITC will be added to the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property, one of the following situations takes place:

- the new child care space is no longer available
- property that was an elig ble expenditure for the child care space is
  - disposed of or leased to a lessee
  - converted to another use

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ______

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . ______ A7

Partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 24. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799** ______

Total recapture of child care spaces investment tax credit (total of line 792, amount A7, and line 799) . . . . ______ B7
Enter at amount B8 in Part 27.

Summary of Investment Tax Credits

Part 27 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount F3 in Part 17) . . . . ______ A8

Recaptured child care spaces ITC (amount B7 in Part 26) . . . . ______ B8

Total recapture of investment tax credit (amount A8 **plus** amount B8) . . . . ______ C8
Enter on line 602 of the T2 return.

Part 28 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5) . . . . ______ D8

ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12) . . . . ______ E8

ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 18) . . . . ______ F8

ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 20) . . . . ______ G8

ITC from child care space expenditures deducted from Part I tax (line 785 in Part 24) . . . . ______ H8

Total ITC deducted from Part I tax (total of amounts D8 to H8) . . . . ______ I8
Enter on line 652 of the T2 return.

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
2,491				2,491

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2020-12-31	4,000			4,000
2019-12-31	6,000			6,000
2018-12-31	2,795			2,795
2017-12-31	2,000			2,000
2016-12-31				
2015-12-31				
2015-11-04				
2015-10-31				
2014-12-31				
2013-12-31				*
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				*
Total	14,795			14,795

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

Canada Revenue Agency Agence du revenu du Canada

Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- 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	16,821,069	
Capital stock (or members' contributions if incorporated without share capital)	103	5,000,000	
Retained earnings	104		
Contributed surplus	105		
Any other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108		
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	42,827,000	
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)		64,648,069 ▶	64,648,069 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)		64,648,069	A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121	4,429,000	
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	4,651,000	
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)		9,080,000 ▶ 9,080,000	B
Capital for the year (amount A **minus** amount B) (if negative, enter “0”)	190	55,568,069	

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 descr bed 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)		55,568,069	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	55,568,069	

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) 55,568,069 x (Taxable income earned in Canada **610** 1,000 / Taxable income 1,000) = **Taxable capital employed in Canada** **690** 55,568,069

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.

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
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- 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	124,233,000
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	50,000,000
Total assets (total of lines 112 to 116)		174,233,000
Total revenue of the corporation for the tax year **	142	63,271,000
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	100,000,000
Total revenue (total of lines 142 to 146)		163,271,000

The corporation is subject to CMT if:
– for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
– for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
– Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
– The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
– The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
– A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

	Line	Amount		Total	
Net income/loss per financial statements *	210			18,973	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220	167			
Provision for deferred income taxes (debits)/cost of future income taxes	222				
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228				
Total patronage dividends received, not already included in net income/loss	232				
281	282				
283	284				
Subtotal		167	▶	167	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			19,140	

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	19,140	
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	19,140	

Amount from line 520		Number of days in the tax year before July 1, 2010 / Number of days in the tax year				
19,140	x	______ / 365	x	4 % =		1
19,140	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year: 365 / 365	x	2.7 % =	517	2

Subtotal (amount 1 **plus** amount 2) 517 3

Gross CMT: amount on line 3 above x OAF **	540	517	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		517	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")		517	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 *		39,335 G		
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		39,335 ▶	620	39,335
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)				39,335 H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)				I
Subtotal (amount H **minus** amount I)				39,335 J
Add:				
Net CMT payable (amount E from Part 3)		517		
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		517 ▶		517 K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	39,852 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)			39,335 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)	517 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:		517 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)		6,000	
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
Hydro One Remote Communities Inc.	[redacted]	2021-12-31

- 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	Hydro One Limited	[redacted]	0	0
2	Hydro One Inc.	[redacted]	0	0
3	2486267 Ontario Inc.	[redacted]	0	0
4	2486268 Ontario Inc.	[redacted]	0	0
5	Hydro One Networks Inc.	[redacted]	50,000,000	100,000,000
6	Acronym Solutions Inc.	[redacted]	0	0
7	Hydro One Telecom Link Limited	[redacted]	0	0
8	Municipal Billing Services Inc.	[redacted]	0	0
9	Hydro One Lake Erie Link Management Inc.	[redacted]	0	0
10	1938454 Ontario Inc.	[redacted]	0	0
11	1943404 Ontario Inc.	[redacted]	0	0
12	Hydro One Indigenous Partnerships Inc.	[redacted]	0	0
13	Norfolk Energy Inc.	[redacted]	0	0
14	Norfolk Power Distribution Inc.	[redacted]	0	0
15	Haldimand County Energy Inc.	[redacted]	0	0
16	Haldimand County Hydro Inc.	[redacted]	0	0
17	Woodstock Hydro Services Inc.	[redacted]	0	0
18	Hydro One Sault Ste. Marie Holdings Inc.	[redacted]	0	0
19	Hydro One Sault Ste. Marie Inc.	[redacted]	0	0
20	Hydro One Sault Ste. Marie Holding Corp.	[redacted]	0	0
21	1228185 Ontario Inc.	[redacted]	0	0
22	Hydro One East-West Tie Inc.	[redacted]	0	0
23	1937680 Ontario Inc.	[redacted]	0	0
24	1937681 Ontario Inc.	[redacted]	0	0
25	2587264 Ontario Inc.	[redacted]	0	0
26	Hydro One Holdings Limited	[redacted]	0	0
27	2587265 Ontario Inc.	[redacted]	0	0
28	Hydro One Investment Holdings Inc.	[redacted]	0	0

	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
29	Orillia Power Distribution Corporation	[redacted]	0	0
30	2835785 Ontario Inc.	[redacted]	0	0
31	Aux Energy Inc.	[redacted]	0	0
32	Hydro One Broadband Solutions Inc.	[redacted]	0	0
33	Olympus Holding Corp.	NR	0	0
		Total	450 50,000,000	550 100,000,000

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.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2021-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the elig ble expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	**120** Telephone number including area code
Nancy Tran	(416) 345-6778

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ______

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 8,185,455

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$ \ 400{,}000}{\$ \ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \ \textbf{minus} \ \$ \ 400{,}000}{\$ \ 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	B Name of qualifying co-operative education program **405**
1.	University of Toronto	Engineering
2.	University of Toronto	Engineering
3.		

	C Name of student **410**	D Start date of WP (see note 1 below) **430**	E End date of WP (see note 2 below) **435**
1.	[redacted]	2021-01-01	2021-04-30
2.		2021-05-01	2021-08-24
3.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	25,987	25.000 %		17
2.		10.000 %	25,987	25.000 %		16
3.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	6,497	3,000	3,000		3,000
2.	6,497	3,000	3,000		3,000
3.					

Ontario co-operative education tax credit (total of amounts in column K) **500** 6,000 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = ... ______ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the elig ble percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Corporate Taxpayer Summary

Corporate information

Corporation's name: Hydro One Remote Communities Inc.

Taxation Year: 2021-01-01 to 2021-12-31

Jurisdiction: Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated: Y

Corporation is related: Y

Number of associated corporations: 33

Type of corporation: Corporation Controlled by a Public Corporation

Total amount due (refund) federal and provincial*: -19,945

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		-5,412,024
Taxable income		
Donations		
Calculation of income from an active business carried on in Canada		
Dividends paid		
Dividends paid – Regular		
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		695,420
Balance of the general rate income pool at the end of the year		
Part I tax (base amount)		

Credits against Part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I		ITC refund	
M&P deduction		Part IV		Dividends refund:	
Foreign tax credit		Part III.1		– Eligible dividends	
Investment tax credits		Other*		– Non-eligible dividends	
Abatement/Other*		Provincial or territorial tax		Instalments	14,462
				Other*	5,483
				Balance due/refund (–)	-19,945

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Investment tax credits	17,286
Non-capital losses	14,388,225
Financial statement reserve	9,414,735
Other reserves	100,535

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	-5,412,024		
Taxable income			
% Allocation	100.00		
Attributed taxable income			
Tax payable before deduction*			
Deductions and credits			
Net tax payable			
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	517		
Instalments and refundable credits	6,000		
Balance due/Refund (-)	-5,483		
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510 . . . 39,852

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
			55,568,069	55,568,069
Hydro One Limited				
Hydro One Inc.				
2486267 Ontario Inc.				
2486268 Ontario Inc.				
Hydro One Networks Inc.	10,000,000		10,000,000	10,000,000
Acronym Solutions Inc.				
Hydro One Telecom Link Limited				
Municipal Billing Services Inc.				
Hydro One Lake Erie Link Management Inc.				
1938454 Ontario Inc.				
1943404 Ontario Inc.				
Hydro One Indigenous Partnerships Inc.				
Norfolk Energy Inc.				
Norfolk Power Distribution Inc.				
Haldimand County Energy Inc.				
Haldimand County Hydro Inc.				
Woodstock Hydro Services Inc.				
Hydro One Sault Ste. Marie Holdings Inc.				
Hydro One Sault Ste. Marie Inc.				

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Hydro One Sault Ste. Marie Holding Corp.				
1228185 Ontario Inc.				
Hydro One East-West Tie Inc.				
1937680 Ontario Inc.				
1937681 Ontario Inc.				
2587264 Ontario Inc.				
Hydro One Holdings Limited				
2587265 Ontario Inc.				
Hydro One Investment Holdings Inc.				
Orillia Power Distribution Corporation				
2835785 Ontario Inc.				
Aux Energy Inc.				
Hydro One Broadband Solutions Inc.				
Olympus Holding Corp.				
Total	10,000,000		65,568,069	65,568,069

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN) and to determine the applicability of Forms CO-1029.8.33.CS and CO-1029.8.33.TE	Paid-up capital used to calculate the $1 million deduction (CO-1137.A and CO-1137.E)	Paid-up capital used to determine the applicability of Form CO-737.SI
Total				

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Alberta

Corporate name	Taxable capital used to calculate the Alberta innovation employment grant (Schedule A29)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)
Total	

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2021-12-31**	**2020-12-31**	**2019-12-31**	**2018-12-31**	**2017-12-31**
Net income	-5,412,024	-642,612	-2,789,810	-5,039,814	-306,376
Taxable income					
Active business income					
Dividends paid					
Dividends paid – Regular					
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year	695,420	695,420	695,420	695,420	695,420
GRIP – end of the year					
Donations					
Balance due/refund (-)	-19,945	-26,590	-15,774	-481,059	-445,609
Line 996 – Amended tax return	☐	☐	☐	☐	X

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	**2021-12-31**	**2020-12-31**	**2019-12-31**	**2018-12-31**	**2017-12-31**
Taxable income before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted taxable income after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	**2021-12-31**	**2020-12-31**	**2019-12-31**	**2018-12-31**	**2017-12-31**
Adjusted taxable income before current year loss carrybacks*	N/A				N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A				N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2021-12-31	2020-12-31	2019-12-31	2018-12-31	2017-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2021-12-31	2020-12-31	2019-12-31	2018-12-31	2017-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks***	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A				N/A

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2021-12-31	2020-12-31	2019-12-31	2018-12-31	2017-12-31
Part I					
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against Part I tax

Taxation year end	2021-12-31	2020-12-31	2019-12-31	2018-12-31	2017-12-31
Small business deduction					
M&P deduction					
Foreign tax credit					
Investment tax credit					
Abatement/other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2021-12-31	2020-12-31	2019-12-31	2018-12-31	2017-12-31
ITC refund					
Dividend refund					
– Eligible dividends					
– Non-eligible dividends					
Instalments	14,462	15,827		460,355	432,571
Other*	5,483	10,763	15,774	20,704	13,038

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2021-12-31	2020-12-31	2019-12-31	2018-12-31	2017-12-31
Net income	-5,412,024	-642,612	-2,789,810	-5,039,814	-306,376
Taxable income					
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income					
Surtax					
Income tax payable before deduction					
Income tax deductions /credits					
Net income tax payable					
Taxable capital					
Capital tax payable					
Total tax payable*	517	395	403	391	13,017
Instalments and refundable credits	6,000	11,158	16,177	21,095	26,055
Balance due/refund**	-5,483	-10,763	-15,774	-20,704	-13,038

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Attached Notes – Summary

Name of the cell Part 1 – Financial statement reserves – Description Form Sch. 13S - Continuity of financial statement reserves (not dedu

2020 Tax Year
Taxprep Attached Note:
this is to offset the movement in RRPR that is balance sheet movement only.

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 1062 – Trade accounts receivable Form Sch. 1599 - Current assets

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Accounts receivable

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 1066 – Taxes receivable Form Sch. 1599 - Current assets

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Income taxes receivable

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 1122 – Inventory parts and supplies Form Sch. 1599 - Current assets

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Fuel, materials and supplies

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 1400 – Due from/investment in related parties Form Sch. 1599 - Current assets

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Inter-company demand facility

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 1480 – Other current assets Form Sch. 1599 - Current assets

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Regulatory assets

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Prior year – GIFI code 1900 – Other tangible capital assets Form Sch. 2008 & 2009 - Tangible capital assets and accumulated an

Property, Plant and Equipment - Administration and service

E51882 - 2022-03-31 Keep this note when rolling forward the file X

Name of the cell Prior year – GIFI code 1901 – Accumulated amortization of oth Form Sch. 2008 & 2009 - Tangible capital assets and accumulated an

Property, Plant and Equipment - Administration and service - Accumulated Depreciation

E51882 - 2022-04-13 Keep this note when rolling forward the file X

Name of the cell GIFI code 1901 – Accumulated amortization of other tangible c Form Sch. 2008 & 2009 - Tangible capital assets and accumulated an

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

PROPERTY, PLANT AND EQUIPMENT - Accumulated Depreciation - Administration and service

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 2629 – Interest payable Form Sch. 3139 - Current liabilities

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Accrued interest

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 2421 – Future (deferred) income taxes Form Sch. 2589 - Long-term assets

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Deferred income tax assets

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 2860 – Due to related parties Form Sch. 3139 - Current liabilities

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Inter-company demand facility

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 3140 – Long-term debt Form Sch. 3450 - Long-term liabilities

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Long-term debt

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 3580 – Accumulated other comprehensive income Form Sch. 3620 - Shareholder equity

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Accumulated other comprehensive loss

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 8000 – Amount – Trade sales of goods and services Form Sch. 8299 - Revenue

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Revenues

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Prior year – GIFI code 8210 – Realized gains/losses on disposa Form Sch. 8299 - Revenue

Gain on disposition of assets?

E51882 - 2022-03-31 Keep this note when rolling forward the file X

Name of the cell GIFI code 8408 – Amount – Well operating, fuel and equipmen Form Sch. 8518 - Cost of sales

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Fuel used for electric generation

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 8450 – Amount – Other direct costs Form Sch. 8518 - Cost of sales

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Cost of power

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Prior year – GIFI code 8670 – Amortization of tangible assets Form Sch. 9367 - Operating expenses

Depreciation, amortization and asset removal costs?

E51882 - 2022-03-31 Keep this note when rolling forward the file X

Name of the cell Part 1 – Deferred tax debit balance at the end of the year Form Sch. 33 - Taxable capital employed in Canada - Large corporati

Deferred income tax assets

E51882 - 2022-03-31 Keep this note when rolling forward the file X

Name of the cell Part 1 – All indebtedness of the corporation represented by bor Form Sch. 33 - Taxable capital employed in Canada - Large corporati

Long-term debt

E51882 - 2022-03-31 Keep this note when rolling forward the file X

Name of the cell GIFI code 8714 – Amount – Interest on long-term debt Form Sch. 9367 - Operating expenses

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Financing charges

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Other – Description Form Sch. 8 - Fixed assets reconciliation

2021 Tax Year
B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

PROPERTY, PLANT AND EQUIPMENT - Construction in Progress
CIP increase (CY $3,489K - PY 3,686K)

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Other – Description Form Sch. 8 - Fixed assets reconciliation

2021 Tax Year
B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS
PROPERTY, PLANT AND EQUIPMENT
Future Use Asset increase (CY$ 3,909K - PY$ 4,534K)

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/B%20-%20FS%20and%20TB
B.1 2020 Remotes FS Final

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Part 1 – Financial statement reserves – Federal – Add Form Sch. 13S - Continuity of financial statement reserves (not dedu

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/
C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
13.1 OPEB tab C140+C141+C98

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-
%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Part 1 – Financial statement reserves – Federal – Add Form Sch. 13S - Continuity of financial statement reserves (not dedu

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
13.5 Regulatory tab F147 to F150

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Part 1 – Financial statement reserves – Federal – Deduct Form Sch. 13S - Continuity of financial statement reserves (not dedu

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
13.5 Regulatory tab F346

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Part 1 – Financial statement reserves – Federal – Add Form Sch. 13S - Continuity of financial statement reserves (not dedu

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
1.21 - DSU tab C36

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 8523 – Amount – Meals and entertainment Form Sch. 9367 - Operating expenses

C.5 working paper

210614 - 2022-06-16 Keep this note when rolling forward the file X

Name of the cell Prior year – GIFI code 8523 – Meals and entertainment Form Sch. 9367 - Operating expenses

https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm
1.1a M&E Support tab D6

E51882 - 2022-04-11 Keep this note when rolling forward the file X

Name of the cell GIFI code 7008 – Cash flow hedge effective portion gains/losse Form Sch. 9998 - Other comprehensive income

C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
TB Closing tab H1160
Account#600551000 - OCI-Amort ARS HedgingGain/Loss

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 9990 – Amount – Current income taxes Form Sch. 140 - Income statement summary

C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
TB Closing tab H1103+H1117
Account#700694000 - Income Tax Expense
Account#700694010 - Income Tax - Discrete

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Line 216 – Financing fees deducted in books Form Sch. 1 - Net income (loss) for income tax purposes

https://teams.hydroone.com/sites/400/4050/2021/07 Tax Returns/Hydro One Remote Communities Inc. (HORCI)/AIT - Remotes FINAL (Feb 10 TB)_T2 2021 WP.xlsx
1.8 Def Fin tab D31

E51882 - 2022-04-11 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
1.3 LTIP tab B32

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

C.1-1, 1.6 tab

210614 - 2022-06-16 Keep this note when rolling forward the file X

Name of the cell Line 295 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

see C.1-1 (1.4 ITC) - Over accrual of 2020 ITC. As the 2020 ITC has been taxed in the T2 - the overaccrual is reversed

205191 - 2022-06-13 Keep this note when rolling forward the file X

Name of the cell Line 395 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

C.1-1 AIT - Tab 8.5 Adds Adj

Deductible removal costs represent the removal costs not associated with fixed assets and therefore deductible for tax.

205191 - 2022-06-13 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

TB (GL 761401)

205191 - 2022-06-13 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

C.1-1 (AIT) - Tab 8.5.2

205191 - 2022-06-13 Keep this note when rolling forward the file X

Name of the cell Line 395 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB)_T2%202021%20WP.xlsx
8.0 NBV-UCC Temp Diff tab D30+D33

E51882 - 2022-04-11 Keep this note when rolling forward the file X

Name of the cell Line 395 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

C.1-1 (AIT) - Tab 13.1

205191 - 2022-06-13 Keep this note when rolling forward the file X

Name of the cell Line 395 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

Statement of cash flow environmental expenditures and FS (Note 13)

GL 753050 balance

Amortization of environmental reg asset offset by cash and since amortization was added back, a deduction is required to reverse out the adjustment

210614 - 2022-06-17 Keep this note when rolling forward the file X

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITI Form Sch. 8 - Capital cost allowance (CCA) workchart

C.1-1 (Tab 8.2)

205191 - 2022-06-13 Keep this note when rolling forward the file X

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITI Form Sch. 8 - Capital cost allowance (CCA) workchart

C.1-1 (Tab 8.2)

205191 - 2022-06-13 Keep this note when rolling forward the file X

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITI Form Sch. 8 - Capital cost allowance (CCA) workchart

C.1-1 (Tab 8.2)

205191 - 2022-06-13 Keep this note when rolling forward the file X

Name of the cell Federal – Proceeds of disposition (Immediate expensing proper Form Sch. 8 - Capital cost allowance (CCA) workchart

2021 Tax Year
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB)_T2%202021%20WP.xlsx
8.2 Tax Adds & Disp tab AA28

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm
8.2 Sch 8 (Included Excluded) tab G20

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITI Form Sch. 8 - Capital cost allowance (CCA) workchart

C-1-1 (Tab 8.2)

205191 - 2022-06-13 Keep this note when rolling forward the file X

Name of the cell Federal – Additions (property subject to subsection 1100(2) ITI Form Sch. 8 - Capital cost allowance (CCA) workchart

2021 Tax Year
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB)_T2%202021%20WP.xlsx
8.2 Tax Adds & Disp tab Z36

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm
8.2 Sch 8 (Included Excluded) tab C26

E51882 - 2022-04-11 Keep this note when rolling forward the file X

Name of the cell Other – Amount Form Sch. 8 - Fixed assets reconciliation

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB)_T2%202021%20WP.xlsx
8.12 Dep tab C41

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Prior year – GIFI code 8623 – Contributions to deferred income Form Sch. 9367 - Operating expenses

https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm
1.2 Cap Items tab E65

E51882 - 2022-04-11 Keep this note when rolling forward the file X

Name of the cell Other – Amount | Form Sch. 8 - Fixed assets reconciliation

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm
8.1 Depn tab D35

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB)_T2%202021%20WP.xlsx

E51882 - 2022-04-28 | Keep this note when rolling forward the file X

Name of the cell Part 2 – Other reserves – Balance at the beginning of the year | Form Sch. 13 - Continuity of reserves

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm
CY TB tab C575 Account#200391010 Customer Security Deposit Account

E51882 - 2022-04-11 | Keep this note when rolling forward the file X

Name of the cell Part 2 – Other reserves – Deduct – Reserve for undelivered goo | Form Sch. 13 - Continuity of reserves

TB (Account 391010)

210614 - 2022-06-16 | Keep this note when rolling forward the file X

Name of the cell Part 1 – Reserves that have not been deducted in calculating ir | Form Sch. 33 - Taxable capital employed in Canada - Large corporati

Taxprep Jumpcode 13S Balance at the end of the year Totals

E51882 - 2022-04-11 | Keep this note when rolling forward the file X

Name of the cell Corporation's salaries and wages paid in the previous tax year | Form ON Sch. 552 - Apprenticeship training tax credit

T37210000 from prior year

210614 - 2022-06-17 | Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

C.5 working paper

210614 - 2022-06-16 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
8.0 NBV-UCC Temp Diff tab D30

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
8.0 NBV-UCC Temp Diff tab D32

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
8.0 NBV-UCC Temp Diff tab D45

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
8.0 NBV-UCC Temp Diff tab D33

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
8.0 NBV-UCC Temp Diff tab D46

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
8.0 NBV-UCC Temp Diff tab D53

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
8.0 NBV-UCC Temp Diff tab D34

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

2021 Tax Year
C.1
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/C%20-%20WPs/C.1%202021%20T2%20WP%20AIT%20-%20Remotes%20FINAL%20(Feb%2010%20TB).xlsx
8.0 NBV-UCC Temp Diff tab D35

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 8623 – Amount – Contributions to deferred income p Form Sch. 9367 - Operating expenses

8.5-1 (Cap Pension)

205191 - 2022-06-13 Keep this note when rolling forward the file X

Name of the cell Amount of contribution Form Sch. 15 - Deferred income plans

C.1-1 wp, tab 8.5.1

Different from FS of $723K due to PYCB being included in FS and the cash outlay was not in FY2021 and hence excluded.

210614 - 2022-06-16 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

Represents the total pension expenses in the year that was not capitalized (C.1-1, 8.5.1 tab)

210614 - 2022-06-16 Keep this note when rolling forward the file X

Name of the cell Tangible capital property – GIFI code 1900 – Other tangible ca Form Sch. 2008 & 2009 - Tangible capital assets and accumulated an

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

PROPERTY, PLANT AND EQUIPMENT - Administration and service

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Tangible capital property – GIFI code 1920 – Other capital asse Form Sch. 2008 & 2009 - Tangible capital assets and accumulated an

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

PROPERTY, PLANT AND EQUIPMENT - Construction
in Progress
Total

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 8670 – Amount – Amortization of tangible assets Form Sch. 9367 - Operating expenses

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

Depreciation, amortization and asset removal costs?

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Prior year – Line 295 – Amount | Form Sch. 1 - Net income (loss) for income tax purposes

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm
1.10 ITCs tab D36

Taxprep Description
2019 provision to return for Ont ITC in OMA

E51882 - 2022-04-28 | Keep this note when rolling forward the file [X]

Name of the cell Prior year – Line 395 – Amount | Form Sch. 1 - Net income (loss) for income tax purposes

https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm
8.1 Depn tab D39

E51882 - 2022-04-28 | Keep this note when rolling forward the file [X]

Name of the cell Management fees | Form Sch. 14 - Miscellaneous payments to residents

C.1-1 wp, tab 14.1

210614 - 2022-06-16 | Keep this note when rolling forward the file [ ]

Name of the cell Management fees | Form Sch. 14 - Miscellaneous payments to residents

C.1-1 wp, tab 14.1

210614 - 2022-06-16 | Keep this note when rolling forward the file [X]

Name of the cell Part 1 – Financial statement reserves – Federal – Deduct | Form Sch. 13S - Continuity of financial statement reserves (not dedu

2020 Tax Year
https://teams.hydroone.com/sites/400/4050/2020/07%20Tax%20Returns/Remotes/C%20-%20WPs/C.1%202020-12-31%20-%20Tax%20Provision%20Remotes_T2%20Purpose.xlsm
13.4 Reserves tab D21

13.0 Sch 13 tab D20

E51882 - 2022-04-28 | Keep this note when rolling forward the file [X]

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

REGULATORY ASSETS AND LIABILITIES

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

B.1A
https://teams.hydroone.com/sites/400/4050/2021/07%20Tax%20Returns/Hydro%20One%20Remote%20Communities%20Inc.%20(HORCI)/B%20-%20FS

E51882 - 2022-04-28 Keep this note when rolling forward the file X

Name of the cell GIFI code 3740 – Other items affecting retained earnings Form Sch. 3849 - Retained earnings/deficit

To match the FS

E51882 - 2022-05-06 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

C.1-1 (Sch 13.1 OPEB)

205191 - 2022-06-12 Keep this note when rolling forward the file

Name of the cell Attached schedule – Amount Form Schedule - Attached schedule with total

C.1-1 (Sch 13.1 OPEB)

205191 - 2022-06-12 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Deduct Form Sch. 13S - Continuity of financial statement reserves (not dedu

C.1-1 (13.3 Enviromental Liability)

205191 - 2022-06-12 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Add Form Sch. 13S - Continuity of financial statement reserves (not dedu

C.1-1 (13.5 RegLiability)

205191 - 2022-06-12 Keep this note when rolling forward the file

Name of the cell Part 1 – Financial statement reserves – Federal – Deduct Form Sch. 13S - Continuity of financial statement reserves (not dedu

C.1-1 AIT (13.5 Regulatory)

205191 - 2022-06-12 Keep this note when rolling forward the file

☐ Name of the cell Corporation's salaries and wages paid in the previous tax year Form ON Sch. 550 - Co-operative education tax credit

T37210000 from prior year

205191 - 2022-06-13 Keep this note when rolling forward the file ☐

☐ Name of the cell Line 395 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

C.1-1 (AIT) - Tab 1.4

205191 - 2022-06-13 Keep this note when rolling forward the file ☐

☐ Name of the cell Line 295 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

C.1-1 (Tab 1.22)

205191 - 2022-06-13 Keep this note when rolling forward the file ☐

☐ Name of the cell Federal – Additions (property subject to subsection 1100(2) ITI Form Sch. 8 - Capital cost allowance (CCA) workchart

C.1-1 AIT (Tab 8.2)

205191 - 2022-06-13 Keep this note when rolling forward the file ☐

☐ Name of the cell Part 2 – Other reserves – Balance at the end of the year – Rese Form Sch. 13 - Continuity of reserves

Ending balance - TB GL 200391010 Customer Security Deposit Account

210614 - 2022-06-16 Keep this note when rolling forward the file X

Name of the cell Attached schedule – Description Form Schedule - Attached schedule with total

Represents the share grants that were settled during the year that were not capitalized.

210614 - 2022-06-16 Keep this note when rolling forward the file X

Name of the cell E – Original registration date of apprenticeship contract or trair Form ON Sch. 552 - Apprenticeship training tax credit

Ss. 89(7) of the Ontario Tax Act states that only apprentices with contract registration date prior to November 15, 2017 would be eligible for Ontario Apprenticeship tax credit.

Per review of C.4 wp, all registration dates were after so no values are included.

210614 - 2022-06-17 Keep this note when rolling forward the file X

Name of the cell A – Trade code – B – Apprenticeship program/ trade name Form ON Sch. 552 - Apprenticeship training tax credit

Entered information on Fed sch 31 but not Ont Sch 552 since eligibility is cut off for contract registration dates before November 15, 2017

210614 - 2022-06-17 Keep this note when rolling forward the file

Name of the cell Line 295 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

OETC is taxed in the year accrued and included in Sch1 L395.7 as part of adjustment to correct for overaccrual of Ontario ITCs.

210614 - 2022-06-17 Keep this note when rolling forward the file X

Name of the cell Line 295 – Amount Form Sch. 1 - Net income (loss) for income tax purposes

1.17 addback (761770)

210614 - 2022-06-17 Keep this note when rolling forward the file

Name of the cell	Line 347 – Non-taxable/deductible other comprehensive incom	Form	Sch. 1 - Net income (loss) for income tax purposes

1.17 (OCI 551000)

210614 - 2022-06-17

Keep this note when rolling forward the file

Name of the cell	Amount of credit	Form	T7B-1 - Schedule of instalment remittances

I.1

210614 - 2022-06-17

Keep this note when rolling forward the file

PROPERTY TAXES AND CROWN LEASE PAYMENTS

1.0 SUMMARY OF PROPERTY TAXES AND CROWN LEASE PAYMENTS

This Exhibit describes property taxes and crown lease payments made in respect of Remotes. These costs are externally imposed and are summarized in Table 1. The property taxes and crown lease payments are included as part of the costing of work as described in Exhibit D, Tab 2, Schedule 2.

Table 1 - Property Taxes and Crown Lease Payments (*in thousands $*)

Category	Board Approved	Historic (Actuals)				Bridge	Test
	2018	2018	2019	2020	2021	2022	2023
Property Taxes	55	52	69	64	66	68	70
Crown Lease Payments	8	13	8	2	16	8	10
Total	**63**	**65**	**77**	**66**	**82**	**76**	**80**

Remotes property taxes are regulated under the *Electricity Act 1998*, the *Municipal Act 2001*, and the *Assessment Act 1990*. Property taxes are paid to the City of Thunder Bay each year on the service centre site located at 680 Beaverhall Place. The total assessed property values are assigned by the Municipal Property Assessment Corporation and updated using the same schedule as the rest of the province.

Remotes pays a nominal fee for the right to use Crown land.

As Table 1 shows, actual payments are materially in line with approved levels. The test year property tax forecast is based on most recent property tax information available.

This page has been left blank intentionally.

REGULATORY COSTS, ONE-TIME COSTS, AND CHARITABLE & POLITICAL CONTRIBUTIONS

1.0 REGULATORY COSTS

Regulatory costs are shown in Exhibit A, Tab 2, Schedule 2, Attachment 1 (App.2-M – Regulatory Costs).

2.0 ONE-TIME COSTS

Other than regulatory costs noted in the above section, there are no one-time costs included in this Application.

3.0 CHARITABLE AND POLITICAL DONATIONS

Remotes confirms that neither charitable donations nor political donations have been included in this Application for recovery.

This page has been left blank intentionally.

COST OF CAPITAL

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and cost of financing of Remotes' capital requirements for the 2023 test year.

2.0 CAPITAL STRUCTURE

Consistent with the Board's Decision in RP-1998-0001 and subsequent Decisions, Remotes is 100% debt-financed and operates as a break-even company. Remotes has no return on equity available to its shareholders. As such, Remotes' cost of capital is based on 100% debt, consisting of 4% deemed short term debt and 96% long term debt.

Long term debt includes $43,000k of long term debt issued to Hydro One Inc., reflecting debt issued by Hydro One Inc. to third party public debt investors, and $10,969k of deemed long term debt.

3.0 DEEMED SHORT-TERM DEBT

The Board has determined that the deemed amount of short-term debt that should be factored into rate setting be fixed at 4% of rate base and that the deemed short-term debt rate be based on the forecast three-month bankers' acceptance rate plus the average spread as determined through a Board staff survey of real market quotes from major banks.[1] For Remotes, the deemed short-term debt rate is 1.17%, consistent with the Deemed Short-Term Debt Rate in the OEB's Cost of Capital Parameter Updates for 2022 Cost of Service Applications for Rates Effective January 1, 2022, dated October 28, 2021. During the course of this proceeding before a final decision is rendered for this application, Remotes expects to update the deemed short

[1] The Board indicated in Appendix D of the December 11, 2009 Cost of Capital Report that, once a year, Board staff will obtain real market quotes from major banks, for issuing spreads over Bankers Acceptance rates to calculate an average spread.

term debt rate for 2023 in accordance with the cost of capital parameters set by the Board for 2023 rates.

4.0 THIRD PARTY LONG-TERM DEBT

The long-term debt rate is calculated as the weighted average cost rate on embedded debt, and new debt (debt issued after the last OEB-approved rate application). The weighted average rate on long-term debt is 4.63% for 2023. Details of Remotes' long-term debt rate calculation for the 2023 test year are shown in Appendix 2-OB filed in Exhibit A, Tab 2, Schedule 2, Attachment 1.

4.1 EMBEDDED DEBT

The Board has determined in its Cost of Capital Report that for embedded debt, the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt. Remotes' embedded long-term debt was issued during the period from 2005 to 2016. The effective cost rates on these embedded debt issues were approved by the Board as part of EB-2017-0051.

4.2 NEW DEBT

The Board has determined in its Cost of Capital Report that the rate for new debt that is held by a third-party public debt investor will be the prudently negotiated contract rate. This would include recognition of premiums and discounts.

There have been no new debt issuances since the previous rate filing.

5.0 DEEMED LONG-TERM DEBT

Deemed long-term debt of $10,969k in 2023 reflects the remaining amount of debt required to balance the total financing with the rate base. In its Decision for EB-2008-0232, the Board indicated that, "For companies with embedded debt, it is the cost of this embedded debt which should be applied to any additional notional (or deemed) debt that is required to balance the capital structure."[2] Accordingly, the deemed long-term debt is calculated at 4.63%.

6.0 COST OF CAPITAL SUMMARY

Remotes' 2023 rate base is $56,218k which results in a weighted average cost on rate base of 3.40%, as shown in the table below.

Table 1 - 2023 Cost of Capital

Particulars	(in $k)	% Of Rate Base	Cost Rate (%)	Weighted Cost Rate %	Cost of Capital (in $k)
Deemed short-term debt	2,249	4.0%	1.17%	0.05%	26
Third Party long-term debt	43,000	76.5%	4.63%	3.54%	1,991
Deemed long-term debt	10,969	19.5%	4.63%	0.90%	508
Total	**56,218**	**100%**		**3.40%**	**$2,525**

The historical 2018 to 2022 debt summary schedules have been provided at Appendix 2-OB at Exhibit A, Tab 2, Schedule 2, Attachment 1. The capital structure and cost of capital for the last Board Approved Year 2018 and the Test Year 2023 have been provided at Appendix 2-OA at Exhibit A, Tab 2, Schedule 2, Attachment 1.

[2] EB-2008-0232, Decision and Order, April 30, 2009, p. 12

This page has been left blank intentionally.

REVENUE REQUIREMENT

1.0 SUMMARY OF REVENUE REQUIREMENT

Remotes recovers the majority of its revenue requirement through the RRRP and other revenues, with the balance of the revenue recovered from Remotes' customers. Remotes follows standard regulatory practice and has calculated the revenue requirement consistent with the principles of the 2006 Electricity Distribution Rate Handbook, as described below.

2.0 CALCULATION OF REVENUE REQUIREMENT

The details of the Revenue Requirement components in 2023 are as follows:

Table 1 - 2023 Revenue Requirement Summary (*in thousands $*)

Revenue Requirement Component	2023 Test Year	Exhibit Reference
OM&A	60,568	Exhibit D, Tab 1, Schedule 1
Depreciation and Amortization	5,454	Exhibit B, Tab 3, Schedule 1
Income Taxes	-	Exhibit D, Tab 5, Schedule 1
Cost of Capital (100% debt)	2,525	Exhibit E, Tab 1, Schedule 1
Total Revenue Requirement – Remotes Operating	**$68,547**	**Exhibit F, Tab 1, Schedule 1**
Watay Transmission Connection Cost – within OM&A	66,000	Exhibit D, Tab 1, Schedule 7
Total Service Revenue Requirement	**$134,547**	
Remotes Annual RRRP-Operating Subsidy	(42,817)	Exhibit G, Tab 1, Schedule 1
Remotes Annual RRRP-Watay Subsidy	(66,000)	Exhibit G, Tab 1, Schedule 1
Other Revenues[1]	(915)	Exhibit F, Tab 3, Schedule 1
Rate Revenue Requirement	**$24,815**	**Exhibit F, Tab 1, Schedule 1**

[1] *Late Payment Charges and Other Distribution Revenues*

The Total Service Revenue Requirement of $134,547k is the amount required by Remotes to ensure the most appropriate, cost-effective solution to respond to corporate objectives, mainly related to public and employee safety, reliability and regulatory requirements. The rate revenue requirement of $24,815k represents the amount to be funded through rates by Remotes' customers.

Full details on the calculation of revenue requirement, including the Determination of Net Utility Income, Statement of Rate Base, Actual Utility Return on Rate Base, Indicated Rate of Return, Requested Rate of Return and the Deficiency in Revenue, are found in the Revenue Requirement Workform filed as Exhibit F, Tab 1, Schedule 1, Attachment 3. The figures contained in this Workform are in $000s. Certain tabs related to Load Forecast, Cost Allocation and Rate Design, are not directly relevant in determining final distribution rates, and thus were not used.

As Remotes does not have balances recorded in RSVA and LV accounts, revenue deficiency calculations do not include price differentials from RSVA or LV charges, and are net of DVA balances that are tracked in RRRP Account. There are no impacts of any change in methodologies on revenue deficiency/sufficiency.

During the course of this proceeding, Remotes plans on submitting an update to its evidence to reflect the most recent Remotes' Board approved business plan that will incorporate an updated revenue requirement.

In accordance with the Chapter 2 filing requirement, the calculations of bridge year forecast revenues at current and proposed rates are filed at Exhibit F, Tab 2, Schedule 1, Attachment 1.

3.0 REVENUE REQUIREMENT – COMPARISON OF YEAR 2023 TEST YEAR FORECAST

Table 2 below compares, by element, the 2018 last OEB-approved Revenue Requirement (EB-2017-0051) against the 2023 test year revenue requirement.

Table 2 - Comparison of Revenue Requirements: 2018 vs. 2023 (*in thousands $, u.o.s.*)

Description	2018 OEB-Approved	2023 Test Year	Var. $	Var. %
OM&A	$21,343	$22,041	$698	3%
Fuel	25,900	30,365	4,465	17%
Cost of Power	-	8,162	8,162	
Watay Transmission Connection Cost	-	66,000	66,000	
Depreciation / Amortization	4,608	5,454	846	18%
Income Taxes	(69)	-	69	
Cost of Capital	2,052	2,525	473	23%
Total Service Revenue Requirement	**$53,834**	**$134,547**	**$80,713**	**150%**
Remotes Annual RRRP-Operating	(35,223)	(42,817)	(7,594)	22%
Remotes Annual RRRP-Watay	-	(66,000)	(66,000)	
Other Revenues[1]	(999)	(915)	84	8%
Rate Revenue Requirement	**$17,612**	**$24,815**	**$7,203**	**41%**

[1]Late Payment Charges and Other Distribution Revenues

Rate Revenue Requirement for the 2023 test year is approximately 40% higher as compared to increased load growth in the communities, and new IPAs joining the Remotes' service territory.

3.1 2023 TEST YEAR VS. 2022 BRIDGE

Table 3 below compares, by element, the 2022 bridge year against the 2023 test year revenue requirement.

Table 3 - Comparison of Revenue Requirements: 2022 vs. 2023 (*in thousands $, u.o.s.*)

Description	2022 Bridge Year	2023 Test Year	Var. $	Var. %
OM&A	$22,534	$22,041	$(493)	-2%
Fuel	41,200	30,365	(10,835)	-26%
Cost of Power	2,795	8,162	5,367	192%
Watay Transmission Connection Cost	21,285	66,000	44,715	210%
Depreciation / Amortization	6,028	5,454	(574)	-10%
Income Taxes	-	-	-	-
Cost of Capital	2,209	2,525	316	14%
Total Service Revenue Requirement	**$96,051**	**$134,547**	**$38,496**	40%
Remotes Annual RRRP-Operating	(49,294)	(42,817)	6,477	-13%
Remotes Annual RRRP-Watay	(21,285)	(66,000)	(44,715)	210%
Other Revenues	(911)	(915)	(4)	0%
Rate Revenue Requirement	**$24,561**	**$24,815**	**$254**	1%

The Rate Revenue Requirement for 2023 test year is 1% higher as compared to 2022 bridge year from the balance of new IPAs joining the Remotes' service territory. For further details, please refer to Exhibit D, Tab 1, Schedule 2.

3.2 2023 TEST YEAR VS. HISTORICAL ACTUALS

Table 4 below compares, by element, the 2018-2021 actuals against the 2022 bridge year and the 2023 test year revenue requirement.

Table 4 - 2018 to 2023 (*in thousands $*)

Description	Historical (Actual)				Bridge	Test
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
OM&A	19,608	21,088	21,186	20,606	22,534	22,041
Fuel	29,406	30,251	29,166	34,481	41,200	30,365
Cost of Power	14	1,463	1,779	1,584	2,795	8,162
Watay Transmission Connection Cost	-	-	-	-	21,285	66,000
Depreciation / Amortization	4,261	7,229	3,979	4,836	6,028	5,454
Income Taxes	(2)	(2)	(3)	-	-	-
Cost of Capital	1,793	1,822	1,813	1,765	2,209	2,525
Total Revenue Requirement – Remotes Operating	**55,080**	**61,851**	**57,920**	**63,272**	**74,766**	**68,547**
Total Revenue Requirement – Watay	**-**	**-**	**-**	**-**	**21,285**	**66,000**
Annual RRRP – Remotes Operating	(35,223)	(35,223)	(35,223)	(35,223)	(35,223)	(42,817)
Annual RRRP - Watay	**-**	**-**	**-**	**-**	(21,285)	(66,000)
Other Revenues	(1,394)	(1,240)	(840)	(1,330)	(911)	(915)
RRRP Variance – Remotes Operating	(359)	(4,512)	491	(4,134)	(14,071)	-
Rate Revenue Requirement	**18,104**	**20,876**	**22,348**	**22,585**	**24,561**	**24,815**
Var. %		*15%*	*7%*	*1%*	*9%*	*1%*

OM&A and Cost of Capital have remained relatively flat year over year. Year-over-year variances in the rate revenue requirement are due to the following factors:

- Increase in fuel costs, primarily driven by increased unit costs and load growth in the communities, partially offset by decreased litres consumed due to nine communities served by Remotes connecting to the grid in 2022 and 2023;

- Increase in cost of power due to existing communities served by Remotes connecting to the grid along with new IPAs being added to Remotes service territory in 2022 and 2023;
- Watay Transmission connection cost began 2022 and will increase as more communities connect to the grid in 2022 and 2023; and,
- Amortization costs increased in 2019 due to an environmental remediation payment for the former diesel site in Pikangikum. There was an increase in the 2022 Bridge year for environmental remediation activities for Cat Lake and Webequie.

4.0 REVENUE DEFICIENCY & DRIVERS OF DEFICIENCY

The revenue deficiency is the difference between the 2023 forecast year revenue requirement and the 2023 forecast year revenues calculated at current rates. For revenue at current rates, it is determined by applying the 2023 forecast of billing units at the expected 2022 base distribution rates. The net revenue deficiency of $602k from 2022 to 2023 is shown in Tab 8 of the Revenue Requirement Workform filed at Exhibit F, Tab 1, Schedule 1, Attachment 3.

The key cost drivers of Remotes' revenue deficiency are increased cost of power and the Watay transmission connection cost, offset by fuel savings as noted above.

This page has been left blank intentionally.

CALCULATION OF REVENUE REQUIREMENT

This exhibit has been filed separately in MS Excel format.

REVENUE REQUIREMENT WORK FORM

This exhibit has been filed separately in MS Excel format.

2023 REVENUE REQUIREMENT WORK FORM

This exhibit has been filed separately in MS Excel format.

PROPOSED CUSTOMER RATES AND REVENUE FORECAST AT CURRENT AND PROPOSED RATES

1.0 INTRODUCTION

Most of Remotes' customers are eligible for Remote Rate Protection under Section 79 of the *Ontario Energy Board Act, 1998*. Under this Act, O. Reg. 442/01 requires the Board to calculate the amount of Rate Protection for these customers. In view of this legislative requirement that sets out rules for setting rates, Remotes did not undertake a cost allocation study prior to filing this application. A cost allocation study would not provide any benefit, as customers cannot be charged the cost of supplying power to them without changes to the legislation. Remotes has not applied the Board's policy to move to fixed distribution rates for its customers because rates for Remotes' customers include the costs of generation and distribution.

Consistent with Remotes' proposal in EB-2008-0232, EB-2012-0137 and EB-2017-0051, which were accepted by the Board, Remotes is proposing to increase rates to customers in its service territory by the average increase in 2022 base distribution rates for all grid-connected residential and general service <50 kW customers in Ontario. OEB staff calculated the average increase following the approach approved in the Board's Decision with Reasons for EB-2008-0232. That Decision prescribed the methodology for calculating average rate increases for other Local Distribution Companies (LDC) to apply in a cost-of-service proceeding. The calculations and information used by Board Staff are included as Exhibit F, Tab 2, Schedule 1, Attachment 2.

Because Remotes' rates include both generation and distribution services, Remotes has applied the OEB-prescribed methodology to the total bill in order to capture changes to both generation and distribution costs. This is consistent with the approach taken in EB-2008-0232, EB-2012-0137, and EB-2017-0051.

The average total bill increase calculated by Board staff for 2021-2022 is 3.72%. The current and proposed rates for each customer class are shown in Table 1.

Table 1 - Current and Proposed Remote Community Rates

YEAR-ROUND RESIDENTIAL (R2)			
	Existing Rates	**Proposed Rates 2023**	**Increase**
Service Charge	$21.64	$22.45	3.72%
Block 1			
First 1,000 kWh	$0.1018	$0.1056	3.72%
Block 2			
Next 1,500 kWh	$0.1358	$0.1409	3.72%
Block 3			
All additional			
(Over 2,500 kWh)	$0.2047	$0.2123	3.72%
RESIDENTIAL SEASONAL(R4)			
	Existing Rates	**Proposed Rates 2023**	**Increase**
Service Charge	$36.57	$37.93	3.72%
Block 1			
First 1,000 kWh	$0.1018	$0.1056	3.72%
Block 2			
Next 1,500 kWh	$0.1358	$0.1409	3.72%
Block 3			
All additional			
(Over 2,500 kWh)	$0.2047	$0.2123	3.72%
GENERAL SERVICE SINGLE PHASE (G1)			
	Existing Rates	**Proposed Rates 2023**	**Increase**
Service Charge	$36.79	$38.16	3.72%
Block 1			
First 6,000 kWh	$0.1141	$0.1183	3.72%
Block 2			
Next 7,000 kWh	$0.1514	$0.1570	3.72%
Block 3			
All additional (Over 13,000 kWh)	$0.2047	$0.2123	3.72%

GENERAL SERVICE THREE PHASE (G3)			
	Existing Rates	**Proposed Rates 2023**	**Increase**
Service Charge	$46.06	$47.77	3.72%
Block 1			
First 25,000 kWh	$0.1141	$0.1183	3.72%
Block 2			
Next 15,000 kWh	$0.1514	$0.1570	3.72%
Block 3			
All additional (Over 40,000 kWh)	$0.2047	$0.2123	3.72%
STREET LIGHTING			
	Existing Rates	**Proposed Rates 2023**	**Increase**
kWh	$0.1132	$0.1174	3.72%
STANDARD A RESIDENTIAL ROAD RAIL			
	Existing Rates	**Proposed Rates 2023**	**Increase**
Block 1 First 250 kWh	$0.6704	$0.6953	3.72%
Block 2 ***All additional (Over 250 kWh)***	$0.7660	$0.7945	3.72%
STANDARD A RESIDENTIAL AIR			
	Existing Rates	**Proposed Rates 2023**	**Increase**
Block 1 First 250 kWh	$1.0121	$1.0498	3.72%
Block 2 ***All additional (Over 250 kWh)***	$1.1077	$1.1489	3.72%
STANDARD A GENERAL SERVICE ROAD RAIL			
	Existing Rates	**Proposed Rates 2023**	**Increase**
kWh	$0.7660	$0.7945	3.72%
STANDARD A GENERAL SERVICE AIR			
	Existing Rates	**Proposed Rates 2023**	**Increase**
kWh	$1.1077	$1.1489	3.72%
STANDARD A GRID CONNECTED			
	Existing Rates	**Proposed Rates 2023**	**Increase**
kWh	$0.3470	$0.3599	3.72%

2.0 REVENUE FORECAST AT CURRENT AND PROPOSED RATES

As discussed in Exhibit C, Tab 1, Schedule 1 Remotes forecasts its customer load annually, based on customer numbers and kWh usage by community and class. This historical data provides the baseline for forecasting revenue usage / kWh sold. Adjustments are made to this baseline data for future years based on average historical growth in usage and historical annual customer changes.

Tables 4 and 5 in Exhibit C, Tab 1, Schedule 1 show the 2022 and 2023 load forecast by category and customer class.

Table 2 below shows the Revenue forecast at current rates by community and by Standard A and Non Standard A customer categories. See Exhibit F, Tab 2, Schedule 1, Attachment 1 for the revenue forecast at current rates by detailed customer category.

Table 2 - 2023 Revenue Forecast at Current Rates (in $k)

Community	Non Standard A		Standard A		Total	
	MWh	Revenue	MWh	Revenue	MWh	Revenue
Armstrong	4,236	610	549	420	4,785	1,031
Bearskin Lake First Nation	2,599	330	637	416	3,237	746
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	6,217	842	1,445	1,029	7,662	1,871
Biscotasing	507	94	-	-	507	94
Cat Lake First Nation	5,548	723	1,341	465	6,889	1,188
Deer Lake First Nation	4,911	642	1,240	1,373	6,151	2,015
Fort Severn First Nation	2,356	319	960	1,063	3,316	1,382
Kiashke Zaaging Anishinaabek (Gull Bay)	1,338	189	240	183	1,578	372
Hillsport	249	42	-	-	249	42
Kasabonika Lake First Nation	4,561	611	1,445	1,029	6,007	1,640
Kingfisher Lake First Nation	2,597	349	781	271	3,378	620
Neskantaga First Nation (Lansdowne House)	1,984	261	862	955	2,846	1,216
Marten Falls First Nation (Ogoki Post)	1,634	218	747	827	2,381	1,045
Muskrat Dam First Nation	1,534	193	549	190	2,083	383
Oba	230	38	-	-	230	38
Pikangikum First Nation	8,996	1,212	2,900	1,006	11,896	2,219
Sachigo Lake First Nation	3,492	466	655	466	4,146	932
Sandy Lake First Nation	11,824	1,551	2,047	2,267	13,871	3,818
Sultan	515	82	-	-	515	82
Wapekeka First Nation	2,427	327	633	451	3,060	778
Wawakapewin First Nation	210	26	165	57	374	84
North Caribou Lake First Nation (Weagamow/Round Lake)	4,933	673	1,146	397	6,079	1,071
Wunnumin Lake First Nation	2,175	271	397	138	2,571	409
Webequie First Nation	2,953	404	661	732	3,615	1,136
Total	**78,027**	**10,476**	**19,398**	**13,737**	**97,425**	**24,213**

Table 3 shows the revenue forecast by community and by Standard A and Non Standard A customer categories at proposed 2023 rates with a May 1, 2023 implementation date. See Exhibit F, Tab 2, Schedule 1, Attachment 1 for the revenue forecast at proposed rates by detailed customer category.

Table 3 - 2023 Revenue Forecast at 2023 Proposed Rates (in $k)

Community	Non Standard A		Standard A		Total	
	MWh	**Revenue**	**MWh**	**Revenue**	**MWh**	**Revenue**
Armstrong	4,236	626	549	431	4,785	1,057
Bearskin Lake First Nation	2,599	338	637	426	3,237	765
Kitchenuhmaykoosib Inninuwug (Big Trout Lake)	6,217	863	1,445	1,055	7,662	1,917
Biscotasing	507	97	-	-	507	97
Cat Lake First Nation	5,548	741	1,341	476	6,889	1,217
Deer Lake First Nation	4,911	658	1,240	1,408	6,151	2,065
Fort Severn First Nation	2,356	327	960	1,090	3,316	1,417
Kiashke Zaaging Anishinaabek (Gull Bay)	1,338	194	240	188	1,578	381
Hillsport	249	43	-	-	249	43
Kasabonika Lake First Nation	4,561	626	1,445	1,055	6,007	1,681
Kingfisher Lake First Nation	2,597	357	781	277	3,378	635
Neskantaga First Nation (Lansdowne House)	1,984	268	862	979	2,846	1,247
Marten Falls First Nation (Ogoki Post)	1,634	224	747	848	2,381	1,071
Muskrat Dam First Nation	1,534	198	549	195	2,083	392
Oba	230	39	-	-	230	39
Pikangikum First Nation	8,996	1,242	2,900	1,031	11,896	2,272
Sachigo Lake First Nation	3,492	477	655	478	4,146	955
Sandy Lake First Nation	11,824	1,590	2,047	2,325	13,871	3,915
Sultan	515	84	-	-	515	84
Wapekeka First Nation	2,427	335	633	462	3,060	797
Wawakapewin First Nation	210	27	165	58	374	86
North Caribou Lake First Nation (Weagamow/Round Lake)	4,933	689	1,146	407	6,079	1,096
Wunnumin Lake First Nation	2,175	278	397	141	2,571	419
Webequie First Nation	2,953	414	661	751	3,615	1,164
Total	**78,027**	**10,735**	**19,398**	**14,081**	**97,425**	**24,815**

The revenue from proposed rates is shown with a May 1, 2023 implementation date. The proposed increase has been pro-rated to show this implementation date.

REVENUE RECONCILIATION – CURRENT TO PROPOSED RATES

This exhibit has been filed separately in MS Excel format.

Company Name	% Change in Base Distribution Rates May 1, 2021 vs. May 1, 2022		Average of Residential & GS<50
	Residential	GS<50	
Alectra Utilities Corporation-Brampton Rate Zone	2.93%	2.82%	2.88%
Alectra Utilities Corporation-Enersource Rate Zone	2.90%	2.89%	2.90%
Alectra Utilities Corporation-Guelph Rate Zone	2.92%	2.75%	2.84%
Alectra Utilities Corporation-Horizon Utilities Rate Zone	2.91%	2.79%	2.85%
Alectra Utilities Corporation-PowerStream Rate Zone	2.92%	2.96%	2.94%
Algoma Power Inc.	4.11%	3.16%	3.64%
Atikokan Hydro Inc.	2.92%	2.81%	2.86%
Bluewater Power Distribution Corporation	2.63%	2.73%	2.68%
Brantford Power Inc.	12.54%	11.30%	11.92%
Burlington Hydro Inc.	8.96%	7.67%	8.32%
Canadian Niagara Power Inc.	6.87%	6.60%	6.73%
Centre Wellington Hydro Ltd.	2.91%	2.96%	2.94%
Chapleau Public Utilities Corporation	4.93%	2.82%	3.87%
Cooperative Hydro Embrun Inc.	0.00%	0.00%	0.00%
E.L.K. Energy Inc.	0.00%	0.00%	0.00%
ENWIN Utilities Ltd.	2.90%	2.83%	2.87%
EPCOR Electricity Distribution Ontario Inc.	3.05%	3.17%	3.11%
ERTH Power Corporation-Goderich Rate Zone	2.64%	2.59%	2.62%
ERTH Power Corporation	2.91%	2.76%	2.83%
Elexicon Energy Inc.-Veridian Rate Zone	2.92%	2.78%	2.85%
Elexicon Energy Inc.-Whitby Rate Zone	2.63%	2.50%	2.57%
Energy Plus Inc.	3.06%	2.97%	3.01%
Entegrus Powerlines Inc.-For Entegrus-Main Rate Zone	3.07%	2.92%	2.99%
Entegrus Powerlines Inc.-For Former St. Thomas Energy Rate Zone	3.07%	2.91%	2.99%
Espanola Regional Hydro Distribution Corporation	28.37%	22.77%	25.57%
Essex Powerlines Corporation	3.07%	3.05%	3.06%
Festival Hydro Inc.	2.91%	2.93%	2.92%
Fort Frances Power Corporation	2.64%	2.65%	2.64%
Greater Sudbury Hydro Inc.	3.29%	3.03%	3.16%
Grimsby Power Incorporated	2.33%	2.33%	2.33%
Halton Hills Hydro Inc.	3.20%	3.30%	3.25%
Hearst Power Distribution Co. Ltd.	16.00%	14.41%	15.20%
Hydro 2000 Inc.	3.05%	2.96%	3.00%
Hydro Hawkesbury Inc.	3.21%	2.95%	3.08%
Hydro One Networks Inc.	5.55%	5.46%	5.50%
Hydro One Networks Inc.-Former Haldimand County Hydro Inc. Service Area	2.76%	2.91%	2.84%
Hydro One Networks Inc.-Former Norfolk Power Distribution Inc. Service Area	2.76%	2.86%	2.81%
Hydro One Networks Inc.-Former Orillia Power Distribution Corporation Service Area	0.00%	0.00%	0.00%
Hydro One Networks Inc.-Former Peterborough Distribution Inc. Service Area	0.00%	0.00%	0.00%
Hydro One Networks Inc.-Former Woodstock Hydro Services Inc. Service Area	2.77%	2.70%	2.73%
Hydro Ottawa Limited	4.71%	5.17%	4.94%
InnPower Corporation	2.92%	2.86%	2.89%
Kingston Hydro Corporation	2.90%	2.88%	2.89%
Kitchener-Wilmot Hydro Inc.	3.04%	2.96%	3.00%
Lakefront Utilities Inc.	3.57%	2.71%	3.14%
Lakeland Power Distribution Ltd.	3.06%	3.14%	3.10%
London Hydro Inc.	5.39%	2.51%	3.95%
Milton Hydro Distribution Inc.	3.05%	3.08%	3.06%
Newmarket-Tay Power Distribution Ltd.-For Former Midland Power Utility Rate Zone	4.86%	4.91%	4.89%
Newmarket-Tay Power Distribution Ltd.-For Newmarket-Tay Power Main Rate Zone	4.01%	4.09%	4.05%
Niagara Peninsula Energy Inc.	2.91%	3.02%	2.97%
Niagara-on-the-Lake Hydro Inc.	2.92%	3.03%	2.97%
North Bay Hydro Distribution Limited	13.18%	9.49%	11.33%
Northern Ontario Wires Inc.	3.20%	3.12%	3.16%
Oakville Hydro Electricity Distribution Inc.	2.63%	2.73%	2.68%
Orangeville Hydro Limited	2.62%	2.67%	2.64%
Oshawa PUC Networks Inc.	3.05%	3.14%	3.09%
Ottawa River Power Corporation	3.68%	1.93%	2.80%
PUC Distribution Inc.	2.91%	2.96%	2.93%

Company Name	% Change in Base Distribution Rates May 1, 2021 vs. May 1, 2022		Average of Residential & GS<50
	Residential	GS<50	
Renfrew Hydro Inc.	2.92%	2.95%	2.94%
Rideau St. Lawrence Distribution Inc.	1.88%	1.80%	1.84%
Sioux Lookout Hydro Inc.	3.06%	2.97%	3.02%
Synergy North Corporation-Kenora Rate Zone	2.62%	2.72%	2.67%
Synergy North Corporation-Thunder Bay Rate Zone	2.92%	3.03%	2.98%
Tillsonburg Hydro Inc.	2.62%	2.56%	2.59%
Toronto Hydro-Electric System Limited	1.47%	1.47%	1.47%
Wasaga Distribution Inc.	3.20%	3.06%	3.13%
Waterloo North Hydro Inc.	2.91%	2.56%	2.73%
Welland Hydro-Electric System Corp.	3.19%	3.13%	3.16%
Wellington North Power Inc.	2.91%	2.91%	2.91%
Westario Power Inc.	2.91%	2.99%	2.95%
Average			**3.72%**

OTHER REVENUES

1.0 OVERVIEW

This Exhibit details revenues that are not derived directly from customer electricity rates. External and Other revenues include revenues based on OEB-approved specific service charges, late payment revenues and revenues where no specific OEB amounts or charges have been set.

External revenues also include work performed for external parties, including Networks, the Electrical Safety Authority, First Nation operated Independent Power Authorities, and work performed on First Nation assets within Remotes' service territory.

In cases where no specific amounts have been set, Remotes costs external work on the basis of cost causality with estimates calculated in the same way as internal work using the standard labour rates (resource rate), equipment rates, material surcharge and overhead rates. See Exhibit D, Tab 2, Schedule 2 for a description of Costing of Work.

2.0 OTHER REVENUE

LATE PAYMENT CHARGES

When the total amount of a customer's bill has not been paid by the due date, a late payment charge may be applied to the outstanding balance. Remotes applies a late payment charge to customer outstanding balances, nineteen (19) days after the billing date. The charge is 1.5% per month and is compounded monthly, resulting in a charge of 19.56% per annum. This is a standard business practice for overdue accounts. Remotes does not propose to change its current Late Payment Charge, as this charge complies with all legislative and regulatory requirements. When Remotes performs non-energy work for customers and the invoice for the work is not paid by the due date, the same late payment interest charges are applied. Late payment charges vary based on actual bills outstanding. The Bridge and Test Year forecasts are based on historical information and number of customers.

SPECIFIC SERVICE CHARGES

Remotes also charges for other specific services that it performs as part of its utility business.

For the Late Payment and Specific Service Charges shown below in Table 1, Remotes does not propose to change the rates for these charges, as they are consistent with charges levied by other Ontario electricity distributors.

Remotes proposes to eliminate the Arrears Certificate and Dispute Meter Test (if meter found correct) specific service charges. Both charges are very rarely charged, if at all. In the unlikely event of additional cost related to these activities they will be absorbed through normal customer account or billing work programs.

Table 1 - Late Payment and Specific Service Charges

Service Description	Charge
Late Payment Charge - per month	1.5%
Late Payment Charge - per anum	19.56%
Reconnection (if in community)	$65.00
Account Set-Up Charge	$30.00
Returned Cheque Charge	$15.00 + bank charges

OTHER MISCELLANEOUS REVENUE

Miscellaneous Generation and Distribution revenue includes capital contribution differences from project costing estimates against the actual costs to perform that work.

EXTERNAL AND UNREGULATED REVENUE

Remotes performs a small amount of external work for other parties. The main areas of work are: 1) assistance to the Electricity Safety Authority and other parties to facilitate their work in the communities; 2) maintenance activities (on streetlights and First Nation-owned generating equipment in Remotes’ service territory); 3) engineering design and assessments related to the connection and integration of renewable generation to Remotes’ electricity distribution and generating systems; 4) work for Networks; and 5) assessments of the IPA generating stations or distribution systems.

Revenues associated with work done for Networks under Service Level Agreements (as discussed in Exhibit A, Tab 5, Schedule 2) are also included in external work. Revenues from external work are shown in Table 2 below. Expenses associated with external work are shown in Exhibit D, Tab 2, Schedule 1.

Table 2 - Total Other Revenues ($000s)

	Historic Years					Bridge	Test
	2018 Board Approved	2018	2019	2020	2021	2022	2023
Energy Late Payment	312	258	318	85	383	287	321
Non-Energy Late Payment	6	12	94	60	86	17	17
Specific Service Charge	12	18	12	8	13	10	10
Miscellaneous Distribution Revenue	26	37	81	61	47	61	61
Miscellaneous Generation Revenue	254	17	0	99	0	0	0
Total	**610**	**342**	**505**	**313**	**529**	**375**	**409**
External and Unregulated Revenue	389	1,057	735	527	801	536	506
Total	**999**	**1,399**	**1,240**	**840**	**1330**	**911**	**915**
Variance		**400**	**(159)**	**(400)**	**490**	**(419)**	**4**

2023 TEST YEAR VS. 2018 OEB-APPROVED (LAST OEB-APPROVED)

- forecast is $85k lower with no significant variances of note.

2023 TEST YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast is $415k lower due to decrease in streetlight projects and other support.

2023 TEST YEAR VS. 2022 BRIDGE YEAR

- forecast is $4k higher with no significant variances of note.

2022 BRIDGE YEAR VS. 2021 ACTUALS (MOST RECENT ACTUALS)

- forecast is $419k lower due to decrease in streetlight projects and other support.

2018 ACTUALS VS 2018 OEB-APPROVED

- actuals were $400k higher due to an increase in CIA assessments, partially offset by a decrease in late payment charges.

YEAR OVER YEAR

- The decrease from 2018 to 2019 is due to a decrease in CIA assessments.
- The decrease from 2019 to 2020 related to the impact of COVID-19 in which late payment fees were waived.
- The increase from 2020 to 2021 related to the re-implementation of late payment fees.

RURAL AND REMOTE RATE PROTECTION REQUIREMENT

1.0 RURAL AND REMOTE RATE PROTECTION (REMOTES OPERATING)

Remotes has two broad categories of customers, Standard A or government customers whose rates have historically been set above cost, and those Residential and General Service customers who benefit from Rural and Remote Rate Protection. These two categories are set out in O. Reg. 442/01, the regulation under the *Ontario Energy Board Act, 1998,* that establishes the rules for Rural and Remote Rate Protection (RRRP). Most of Remotes' customers pay rates that are subsidized by RRRP and are set well below the per kWh cost to serve from diesel fuel.

The revenues to fund the RRRP program are derived from charges to all electricity users in the grid-connected part of the Province. Under current Board-approved processes, the IESO collects the total amount of RRRP and maintains a variance account to track over or under collection of RRRP to meet the program's requirements. The IESO distributes Remotes' OEB-approved share of RRRP revenues in equal installments throughout the year.

Remotes operates under a cost-recovery model applied to achieve an after-tax break-even operating result. Any excess or deficiency in RRRP revenues necessary to break-even is added to, or drawn from, the RRRP Variance Account. Further information about this account can be found in Exhibit H, Tab 1, Schedule 1. RRRP transfers account for over half of Remotes' revenues each year. RRRP for customers in Remotes' service area is currently approved at $35,223K per year.[1]

Sections 4(2) and 4(3) of Regulation 442/01 set out the rules for determining the level of rural and remote rate protection for Remotes' customers as follows:

[1] See EB-2017-0051.

> The Board shall calculate the amount by which Hydro One Remote Communities Inc.'s forecasted revenue requirement for the year as approved by the Board exceeds Hydro One Remote Communities Inc.'s forecasted consumer revenues for the year, as approved by the Board.

1.1 PROPOSAL TO ADJUST RRRP (REMOTES OPERATING) 2023 AMOUNT BY OEB-APPROVED INFLATION ADJUSTMENT

As indicated above, Remotes operates under a cost-recovery model applied to achieve an after-tax break-even operating result. Any excess or deficiency in RRRP revenues necessary to break-even is added to, or drawn from, the RRRP Variance Account (RRRPVA). In 2021, RRRP (Remotes Operating) represented 62% ($39.36M of $63.27M) of total revenue, which raised the RRRPVA by $4.13M.

Consistent with other electricity distribution filers, Remotes follows a five-year rebasing schedule whereby in year one, rates are set based on a cost of service, and in the following four years, rate are adjusted through a price-cap incentive rate-setting mechanism to be approved by the OEB in an IRM application. During the IRM years, the portion of Remotes' revenue requirement recoverable through customer rates is adjusted pursuant to OEB inflation parameters, but the revenues recovered through the RRRP are not. Given that the portion of Remotes' revenue requirement recoverable through the RRRP (Remotes Operating) remains unchanged until the next cost of service application, Remotes has been experiencing a shortfall annually as evidenced in Exhibit H, Tab 1, Schedule 1. As a result, the balance in the RRRPVA variance account which must be cleared at the time of rebasing is significant.

In order to lower the balance in the RRRPVA which must be cleared at the time of rebasing, Remotes is requesting approval for future RRRP (Remotes Operating) subsidies to be adjusted in conjunction with approved IRM customer rate changes during the IRM years, such that the following is achieved until the next rebasing application.

2024 RRRP(RO) = 2023 RRRP(RO) * 2024 OEB-approved I-X factor

2025 RRRP(RO) = 2024 RRRP(RO) * 2025 OEB-approved I-X factor

2026 RRRP(RO) = 2025 RRRP(RO) * 2026 OEB-approved I-X factor

2027 RRRP(RO) = 2026 RRRP(RO) * 2027 OEB-approved I-X factor

Note: Where RRRP(RO) represents RRRP (Remotes Operating)

As this proposal is expected to reduce the balance in the total RRRPVA in future cost of service proceedings, Remotes believes that this proposal will benefit ratepayers as there should be smaller variances in the RRRPVA over time.

Had this proposal been implemented in the past, the 2021 year-end RRRPVA would have been reduced by $3,456k[2]. A historical example of the proposed change is shown in the table below.

Table 1 - Example of the RRRP (Remotes Operating) Subsidy IRM Rate Change Escalation Based on Remotes 2018 to 2021 Actuals (*in thousands, $*)

	Actuals				
	2018	**2019**	**2020**	**2021**	**Total**
RRRP Variance Account, Opening Balance (Note 1)	1,218	4,541	5,561	4,005	
Annual Rural and Remote Rate Protection (Note 1)	(35,223)	(35,223)	(35,223)	(35,223)	(140,892)
Subsidy increase deferred (Note 1)	2,964	(2,964)	0	0	0
RRRP - IRM Increase (Historical/Proposed) (Note 2)	0	(528)	(1,065)	(1,863)	(3,456)
Total Energy Revenue (Note 1)	(19,498)	(22,116)	(23,188)	(23,915)	(88,717)
Total Costs (Note 1)	55,080	61,851	57,920	63,272	238,123
Net (Income)/Loss [change in RRRP] (Note 3)	3,323	1,020	(1,556)	2,271	5,058
RRRP Variance Account, Ending Balance (Note 4)	**4,541**	**5,561**	**4,005**	**6,277**	

Note 1: Based on the data presented in Remotes RRRPVA Reconciliation Summary 2018-2021 in Exhibit H-2-1-6.
Note 2: The additional amount if the RRRP (Remotes Operating) subsidy grew in conjunction with the approved IRM customer rates (i.e.+1.5% -2019 Rates in EB-2018-0043; +1.5% -2020 Rates in EB-2019-0045; +2.2% - 2021 Rates in EB-2020-0032)
Note 3: Represents the summation of RRRP subsidy (including the IRM proposal amount), Total Energy Revenue and Total Costs.
Note 4: The resultant RRRP variance account balance assuming the proposal for an IRM rate adjusted RRRP subsidy.

[2] The $3,456k reduction represents the difference between the audited 2021 year-end RRRPVA balance of $9,732k as per Exhibit H, Tab 1, Schedule 1; and the 2021 year-end RRRPVA balance of $6,277k from the proposed example in Table 1.

2.0 RURAL AND REMOTE RATE PROTECTION (WATAY)

In 2016, the provincial government designated Wataynikaneyap Power Limited Partnership (Watay) to construct a Transmission (Tx) line to connect 16 remote First Nation communities to the grid, 10 of which are currently served by Remotes and 6 of which are unregulated Independent Power Authorities (IPAs).

As noted in OEB Decision and Order in EB-2018-0190[3] O. Reg. 442/01 (Rural or Remote Electricity Rate Protection) was amended effective July 1, 2016 “to allow RRRP to be used to cover a portion of the costs required to build and operate the lines that would connect remote First Nations communities to the transmission grid”.

The cost recovery framework will charge the cost of the Tx facilities to Remotes as a direct expense, which will be recovered through the RRRP. Watay has projected that the cost to Remotes will grow to be approximately $104M per year over the Plan period (EB-2018-0190). Remotes will require RRRP (Watay) funding for Watay related flow-through costs.[4] 2022 RRRP (Watay) amounts have been set by decision EB-2021-0300. Watay’s 2023 Electricity Transmission Rates application (EB-2022-0149), currently before the OEB, will determine the 2023 RRRP (Watay) amounts for Remotes.

[3] Dated April 1, 2019 and revised April 29, 2019.
[4] See EB-2018-0190.

3.0 FORECAST RRRP REQUIREMENT

Table 2 - Forecasted RRRP Requirement (*in thousands, $*)

Item	
2023 Revenue Requirement – Remotes Operating	**68,547**
2023 Revenue Requirement – Watay	**66,000**
Less: 2023 Revenue from Customer Rates	**(24,815)**
Other Revenues	**(915)**
Annual RRRP Level for 2023	**108,817**
Recovery of Balance of RRRP Variance Account (Note 1)	**1,946**
Total RRRP Level	**110,763**
Recovery of residual COVID-19 Forgone Revenue Rate Rider	**(10)**
Total RRRP Level for 2023	**110,753**

Note 1: Remotes is proposing to dispose of the December 31, 2021 audited RRRPVA total balance of $9,732k equally over a five-year term ($1,946k/year) as outlined in Exhibit H, Tab 1, Schedule 1

This page has been left blank intentionally.

EXAMPLE OF THE RRRP (REMOTES OPERATING) SUBSIDY IRM RATE CHANGE ESCALATION BASED ON REMOTES 2018 TO 2021 ACTUALS

This exhibit has been filed separately in MS Excel format.

CUSTOMER BILL IMPACTS

1.0 INTRODUCTION

The impacts of the proposed changes for Remotes' current customers are shown in Tables 1 to 4 below. The rates have been increased by 3.72%; however, the total bill impacts may differ slightly from 3.72% because the rates levied to customers are rounded at the appropriate decimal place (four for kWh charges and two for service charges).

In this application, the bill impacts for all customer classes will be less than 10% per year. For this reason, no bill impact mitigation plan is required.

2.0 NON STANDARD A CUSTOMERS

2.1 RESIDENTIAL YEAR ROUND (R2)

The Year-Round Residential classification applies to a customer's principal residence and may include additional buildings served through the same meter, provided they are not rental income units.

To be classified as year-round residential, all of the following criteria must be met:

1. Occupants must state that this is their principal residence for the purposes of the *Income Tax Act*;
2. The occupant must live in this residence for at least eight months of the year;
3. The address of this residence must appear on the occupant's electrical bill, driver's license, credit card invoice, etc.;
4. Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for that purpose at the address of this residence.

Table 1 below shows the percentage change in monthly bills of the proposed 2023 rates compared to the current 2022 rates. The analysis is based on the total bill, including a monthly service charge and HST.

Table 1 - Bill Impacts for Residential (R2) Customers

RESIDENTIAL YEAR ROUND (R2)							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
100	$31.82	$27.73	$33.01	$28.77	1.19	1.04	3.74%
250	$47.09	$41.04	$48.85	$42.57	1.76	1.53	3.74%
500	$72.54	$63.22	$75.25	$65.58	2.71	2.36	3.74%
750	$97.99	$85.40	$101.65	$88.59	3.66	3.19	3.74%
1000	$123.44	$107.58	$128.05	$111.60	4.61	4.02	3.73%
2000	$259.24	$225.93	$268.95	$234.39	9.71	8.46	3.75%
2500	$327.14	$285.10	$339.40	$295.79	12.26	10.68	3.75%

2.2 RESIDENTIAL SEASONAL (R4)

This classification is comprised of cottages, chalets and camps or any other residential service not meeting the year-round residential criteria. Table 2 gives a comparison of current versus proposed rates for Residential Seasonal customers. The analysis is based on the total bill, including a monthly service charge.

Table 2 - Bill Impacts for Residential Seasonal (R4) Customers

RESIDENTIAL SEASONAL (R4)							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
100	$46.75	$40.74	$48.49	$42.26	1.74	1.52	3.72%
250	$62.02	$54.05	$64.33	$56.06	2.31	2.01	3.72%
500	$87.47	$76.23	$90.73	$79.07	3.26	2.84	3.73%
750	$112.92	$98.41	$117.13	$102.08	4.21	3.67	3.73%
1000	$138.37	$120.59	$143.53	$125.09	5.16	4.50	3.73%
2000	$274.17	$238.94	$284.43	$247.88	10.26	8.94	3.74%

2.3 GENERAL SERVICE SINGLE PHASE

This classification applies to any non-Standard A service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative and auxiliary services. It also includes combination services where one property has a variety of uses and for all multiple services except residential. Single Phase service uses single phase power. The bill analysis is based on the total bill, including a service charge.

Table 3 - Bill Impacts for General Service Single Phase (G1)

GENERAL SERVICE SINGLE PHASE (G1)							
Scenario (kWh)	Current Bill	Current Bill with HST (includes rebate)	Proposed Bill	Proposed Bill with HST (includes rebate)	$ Change	$ Change with HST (includes rebate)	Percentage Change
1000	$150.89	$131.50	$156.46	$136.35	5.57	4.85	3.69%
2000	$264.99	$230.94	$274.76	$239.45	9.77	8.51	3.69%
3000	$379.09	$330.38	$393.06	$342.55	13.97	12.17	3.69%
5000	$607.29	$529.25	$629.66	$548.75	22.37	19.50	3.68%

2.4 GENERAL SERVICE THREE PHASE

This classification applies to non-residential customers who use three phase power. The bill analysis is based on the total bill, including a service charge.

Table 4 - Bill Impacts for General Service (G3)

GENERAL SERVICE THREE PHASE (G3)							
Scenario (kWh)	Current Bill	Current Bill with HST (includes rebate)	Proposed Bill	Proposed Bill with HST (includes rebate)	$ Change	$ Change with HST (includes rebate)	Percentage Change
2000	$274.26	$239.02	$284.37	$247.83	10.11	8.81	3.69%
3000	$388.36	$338.46	$402.67	$350.93	14.31	12.47	3.68%
5000	$616.56	537.33	$639.27	$557.12	22.71	19.79	3.68%
10,000	$1,187.06	$1,034.52	$1,230.77	$1,072.62	43.71	38.09	3.68%

2.5 STREET LIGHTING

This classification applies to unmetered street lights. The energy consumption for streetlights is based on Remotes' profile for street lighting load, which provides the amount of time each month that the street lights are operating. The bill analysis is based on the total bill.

Table 5 - Rate Impacts for Streetlights

STREET LIGHTING							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
500	$56.60	$49.33	$58.70	$51.16	2.10	1.83	3.71%
2000	$226.40	$197.31	$234.80	$204.63	8.40	7.32	3.71%
4000	$452.80	$394.62	$469.60	$409.26	16.80	14.64	3.71%

3.0 STANDARD A CUSTOMERS

This classification is applicable to all Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.;
- social housing;
- a recreational or sports facility;
- a radio, television or cable television facility; and
- a library.

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source.

3.1 STANDARD A RESIDENTIAL ROAD/RAIL

This classification applies to residential customers who occupy premises funded in whole or in part by government, and who live in communities accessible by all season roads and by rail. The bill analysis is based on the total bill, including a service charge.

Table 6 - Bill Impacts for Standard A Residential Road/Rail

STANDARD A RESIDENTIAL ROAD/RAIL							
Scenario (kWh)	Current Bill	Current Bill with HST (includes rebate)	Proposed Bill	Proposed Bill with HST (includes rebate)	$ Change	$ Change with HST (includes rebate)	Percentage Change
100	$67.04	$58.43	$69.53	$60.60	2.49	2.17	3.71%
250	$167.60	$146.06	$173.83	$151.49	6.23	5.43	3.71%
500	$359.10	$312.96	$372.45	$324.59	13.35	11.63	3.72%
750	$550.60	$479.85	$571.08	$497.69	20.48	17.84	3.72%
1000	$742.10	$646.74	$769.70	$670.79	27.60	24.05	3.72%
2000	$1,508.10	$1,314.31	$1,564.20	$1,363.20	56.10	48.89	3.72%

3.2 STANDARD A RESIDENTIAL AIR ACCESS

This classification applies to residential customers who occupy premises funded in whole or in part by government, and who live in communities that are not accessible by year-round roads. The bill analysis is based on the total bill.

Table 7 - Bill Impacts for Standard A Residential Air Access

STANDARD A RESIDENTIAL AIR ACCESS							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
250	$253.03	$220.51	$262.45	$228.73	9.42	8.21	3.72%
500	$529.95	$461.85	$549.68	$479.04	19.73	17.19	3.72%
750	$806.88	$703.19	$836.90	$729.36	30.03	26.17	3.72%
1000	$1,083.80	$944.53	$1,124.13	$979.67	40.33	35.14	3.72%
2000	$2,191.50	$1,909.89	$2,273.03	$1,980.94	81.53	71.05	3.72%

3.3 STANDARD A GENERAL SERVICE ROAD/RAIL

This classification applies to general service customers who occupy premises funded in whole or in part by government, in communities that are accessible by year-round roads. The bill analysis is based on the total bill.

Table 8 - Rate Impacts for Standard A General Service Road/Rail

STANDARD A GENERAL SERVICE ROAD RAIL							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
1000	$766.00	$667.57	$794.50	$692.41	28.50	24.84	3.72%
2000	$1,532.00	$1,335.14	$1,589.00	$1,384.81	57.00	49.68	3.72%
5000	$3,830.00	$3,337.85	$3,972.50	$3,462.30	142.50	124.19	3.72%

3.4 STANDARD A GENERAL SERVICE AIR ACCESS

This classification applies to general service customers who occupy premises funded in whole or in part by government, in communities that are not accessible by year-round roads. The bill analysis is based on the total bill.

Table 9 - Rate Impacts for Standard A General Service Air Access

STANDARD A GENERAL SERVICE AIR ACCESS							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
1000	$1,107.70	$965.36	$1,148.90	$1,001.27	41.20	35.91	3.72%
2000	$2,215.40	$1,930.72	$2,297.80	$2,002.53	82.40	71.81	3.72%
5000	$5,538.50	$4,826.80	$5,744.50	$5,006.33	206.00	179.53	3.72%

3.5 STANDARD A GRID CONNECTED

This classification is applicable to all Standard A customers that are connected to the grid.

Table 10 - Rate Impacts for Standard A Grid Connected

STANDARD A GRID CONNECTED							
Scenario (kWh)	**Current Bill**	**Current Bill with HST (includes rebate)**	**Proposed Bill**	**Proposed Bill with HST (includes rebate)**	**$ Change**	**$ Change with HST (includes rebate)**	**Percentage Change**
1000	$347.00	$302.41	$359.90	$313.65	12.90	11.24	3.72%
2000	$694.00	$604.82	$719.80	$627.31	25.80	22.48	3.72%
5000	$1,735.00	$1,512.05	$1,799.50	$1,568.26	64.50	56.21	3.72%

This page has been left blank intentionally.

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

NON STANDARD A YEAR ROUND RESIDENTIAL SERVICE CLASSIFICATION – R2

This classification refers to a residential service that is the principal residence of the customer. This classification may include additional buildings served through the same meter, provided they are not rental income units. To be classed as year round residential, all of the following criteria must be met:

- Occupants must state that this is their principal residence for purposes of the Income Tax Act;
- The occupant must live in this residence for at least 8 months of the year;
- The address of this residence must appear on the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.;
- Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Service Charge	$	21.64
Electricity Rate - First 1,000 kWh	$/kWh	0.1018
Electricity Rate - Next 1,500 kWh	$/kWh	0.1358
Electricity Rate - All Additional kWh	$/kWh	0.2047

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

NON STANDARD A SEASONAL RESIDENTIAL SERVICE CLASSIFICATION – R4

This classification is comprised of any residential service not meeting the year-round residential criteria. As such, the seasonal residential class includes cottages, chalets, and camps. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Service Charge	$	36.57
Electricity Rate - First 1,000 kWh	$/kWh	0.1018
Electricity Rate - Next 1,500 kWh	$/kWh	0.1358
Electricity Rate - All Additional kWh	$/kWh	0.2047

Hydro One Remote Communities Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

NON STANDARD A GENERAL SERVICE SINGLE PHASE SERVICE CLASSIFICATION – G1

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Single Phase customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Service Charge	$	36.79
Electricity Rate - First 6,000 kWh	$/kWh	0.1141
Electricity Rate - Next 7,000 kWh	$/kWh	0.1514
Electricity Rate - All Additional kWh	$/kWh	0.2047

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

NON STANDARD A GENERAL SERVICE THREE PHASE SERVICE CLASSIFICATION – G3

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Three Phase customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Service Charge	$	46.06
Electricity Rate - First 25,000 kWh	$/kWh	0.1141
Electricity Rate - Next 15,000 kWh	$/kWh	0.1514
Electricity Rate - All Additional kWh	$/kWh	0.2047

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

STREET LIGHTING SERVICE CLASSIFICATION

The energy consumption for street lights is estimated based on Remotes' profile for street lighting load, which provides the amount of time each month that the street lights are operating. Streetlight charges include:

- An energy charge based on installed load, at a rate approved annually (Dollars per kWh x # of fixtures x billing);
- A pole rental charge approved annually, when the light is attached to a Remotes' pole.

Remotes must approve the location of new lighting installations on its poles and the streetlight owner must enter into an agreement to use such poles. Remotes will make the electrical service connection of all streetlights to the distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate	$/kWh	0.1132

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

STANDARD A RESIDENTIAL ROAD/RAIL ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Aboriginal Affairs and Northern Development Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate - First 250 kWh	$/kWh	0.6704
Electricity Rate - All Additional kWh	$/kWh	0.7660

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

STANDARD A RESIDENTIAL AIR ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are not accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate - First 250 kWh	$/kWh	1.0121
Electricity Rate - All Additional kWh	$/kWh	1.1077

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

STANDARD A GENERAL SERVICE ROAD/RAIL ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate	$/kWh	0.7660

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

STANDARD A GENERAL SERVICE AIR ACCESS SERVICE

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are not accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate	$/kWh	1.1077

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

STANDARD A GRID CONNECTED SERVICE CLASSIFICATION

This classification is applicable to all Standard A customers in communities that are connected to the grid and are not accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate	$/kWh	0.3470

Hydro One Remote Communities Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	4.55

Hydro One Remote Communities Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2022
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0034

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration		
Arrears certificate	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late payment - per month	%	1.50
(effective annual rate 19.56% per annum or 0.04896% compounded daily rate)		
Reconnection – if in community	$	65.00

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

NON STANDARD A YEAR ROUND RESIDENTIAL SERVICE CLASSIFICATION – R2

This classification refers to a residential service that is the principal residence of the customer. This classification may include additional buildings served through the same meter, provided they are not rental income units. To be classed as year round residential, all of the following criteria must be met:

- Occupants must state that this is their principal residence for purposes of the Income Tax Act;
- The occupant must live in this residence for at least 8 months of the year;
- The address of this residence must appear on the occupant's electric bill, driver's licence, credit card invoice, property tax bill, etc.;
- Occupants who are eligible to vote in Provincial or Federal elections must be enumerated for this purpose at the address of this residence.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Service Charge	$	22.45
Electricity Rate - First 1,000 kWh	$/kWh	0.1056
Electricity Rate - Next 1,500 kWh	$/kWh	0.1409
Electricity Rate - All Additional kWh	$/kWh	0.2123

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

NON STANDARD A SEASONAL RESIDENTIAL SERVICE CLASSIFICATION – R4

This classification is comprised of any residential service not meeting the year-round residential criteria. As such, the seasonal residential class includes cottages, chalets, and camps. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Service Charge	$	37.93
Electricity Rate - First 1,000 kWh	$/kWh	0.1056
Electricity Rate - Next 1,500 kWh	$/kWh	0.1409
Electricity Rate - All Additional kWh	$/kWh	0.2123

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

NON STANDARD A GENERAL SERVICE SINGLE PHASE SERVICE CLASSIFICATION – G1

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Single Phase customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Service Charge	$	38.16
Electricity Rate - First 6,000 kWh	$/kWh	0.1183
Electricity Rate - Next 7,000 kWh	$/kWh	0.1570
Electricity Rate - All Additional kWh	$/kWh	0.2123

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

NON STANDARD A GENERAL SERVICE THREE PHASE SERVICE CLASSIFICATION – G3

This classification is applicable to any service that does not fit the description of the year-round residential or seasonal residential. Generally, it is comprised of commercial, administrative, recreational, and auxiliary services. It includes combination of services where a variety of uses are made of the service by the owner of one property, and all multiple services except residential. This classification is applicable to General Service Three Phase customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Service Charge	$	47.77
Electricity Rate - First 25,000 kWh	$/kWh	0.1183
Electricity Rate - Next 15,000 kWh	$/kWh	0.1570
Electricity Rate - All Additional kWh	$/kWh	0.2123

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STREET LIGHTING SERVICE CLASSIFICATION

The energy consumption for street lights is estimated based on Remotes' profile for street lighting load, which provides the amount of time each month that the street lights are operating. Streetlight charges include:

- An energy charge based on installed load, at a rate approved annually (Dollars per kWh x # of fixtures x billing);
- A pole rental charge approved annually, when the light is attached to a Remotes' pole.

Remotes must approve the location of new lighting installations on its poles and the streetlight owner must enter into an agreement to use such poles. Remotes will make the electrical service connection of all streetlights to the distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate	$/kWh	0.1174

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STANDARD A RESIDENTIAL ROAD/RAIL ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Aboriginal Affairs and Northern Development Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate - First 250 kWh	$/kWh	0.6953
Electricity Rate - All Additional kWh	$/kWh	0.7945

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STANDARD A RESIDENTIAL AIR ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to residential customers in communities that are not accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate - First 250 kWh	$/kWh	1.0498
Electricity Rate - All Additional kWh	$/kWh	1.1489

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STANDARD A GENERAL SERVICE ROAD/RAIL ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate	$/kWh	0.7945

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STANDARD A GENERAL SERVICE AIR ACCESS SERVICE CLASSIFICATION

Standard A rates are applicable to all accounts paid directly or indirectly out of Federal and/or Provincial government revenue, subject to the following exceptions:

- Canada Post Corporation, Hydro One Inc. or a subsidiary of Hydro One Inc.
- social housing
- a recreational or sports facility
- a radio, television or cable television facility
- a library

Any Standard A account may be reclassified as General Service, Residential Year-Round or Residential-Seasonal at any time. To reclassify a Standard A account, a letter from the accountable Federal and/or Provincial Government agency must be provided to Remotes stating that the account does not receive any direct and/or indirect funding of a continuous nature. An alternative to this letter would be a declaration from a Director of the organization stating that the organization receives no funding. This declaration must be accompanied by an audited statement, which includes the funding source. An example of direct funding is an MTO account paid directly by MTO. An example of indirect funding is a First Nation School account paid by a First Nation through funding by Indian and Northern Affairs Canada. Further servicing details are available in the distributor's Conditions of Service.

This classification is applicable to all non-residential Standard A customers in communities that are not accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate	$/kWh	1.1489

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	4.55

Hydro One Remote Communities Inc.
Proposed Remote Communities Rate Schedule
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

STANDARD A GRID CONNECTED SERVICE CLASSIFICATION

This classification is applicable to all Standard A customers in communities that are connected to the grid and are not accessible by a year-round road or by rail.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES

Electricity Rate	$/kWh	0.3599

Hydro One Remote Communities Inc.
TARIFF OF RATES AND CHARGES
Effective Date May 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned Cheque (plus bank charges)	$	15.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
~~Collection/Disconnection/Load Limiter/~~Reconnection – if in Community	$	65.00

RATES GENERATOR MODEL WORKSHEET 2023

This exhibit has been filed separately in MS Excel format.

PRORATED RATE AND BILLS FOR 2023

This exhibit has been filed separately in MS Excel format.

PROPOSED REMOTE COMMUNITIES RATE SCHEDULE

This exhibit has been filed separately in MS Excel format.

DEFERRAL AND VARIANCE ACCOUNTS

1.0 DESCRIPTION OF REGULATORY ACCOUNTS

Remotes has two Regulatory Accounts: the Rural and Remote Rate Protection Variance Account (RRRPVA); and the Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation. These regulatory accounts have been established consistent with the Accounting Procedures Handbook, and any subsequent Board direction. The account balances reflect what is in the trial balance, and there were no adjustments made to account balances previously approved by the Board.

Table 1 - Regulatory Accounts (*in thousands, $*)

Regulatory Account	Historical				Bridge
	2018	**2019**	**2020**	**2021**	**2022 Forecast**
Rural and Remote Rate Protection Variance Account	4,541[1]	6,089	5,598	9,732	45,088
Rate Rider for Recover of COVID-19 Forgone Revenue from Postponing Rate Implementation	0	0	120	(10)	(10)
Total	**4,541**	**6,089**	**5,718**	**9,722**	**45,078**

Note 1: In Remotes COS Application (EB-2017-0051) for 2018-22 Rates, the RRRPVA balance was not cleared and the balance was carried over resulting in an opening 2018 balance of $1,218k.

1.1 RURAL AND REMOTE RATE PROTECTION VARIANCE ACCOUNT

Remotes conducts its operations under a cost recovery model applied to achieve break-even results of operations after the inclusion of income taxes. Any excess or deficiency in rural and remote rate protection (RRRP) revenues necessary to ensure break-even results in operations is added to, or drawn from, the RRRPVA. The account was originally established in 2003 pursuant to O.Reg. 442/01. In its RP-2005-0020/EB-2005-0511 Decision, and in subsequent Decisions in EB-2012-0137 and EB-2017-0051, the Board approved continuation of this account. In the EB-2017-0051 Decision, the balance of this account was not cleared; the 2017 balance of $1,218k can be found in Exhibit H, Tab 2, Schedule 1, Attachment 1. Detailed information about the balances in this account from 2018 to 2021 can be found in Exhibit H, Tab 2, Schedule 1, Attachments 2 to

5. This account is reported to the Board on a quarterly basis consistent with the Board's Reporting and Record Keeping Requirements.

No interest is applied to the RRRPVA given that the intent of the account is to serve as a tool to achieve a break-even operating result. Adding interest would result in a circular impact on the RRRPVA as the interest cost would itself impact that year's operating result, causing a revision to the amount added to or withdrawn from the RRRPVA.

1.2 RATE RIDER FOR RECOVERY OF COVID-19 FORGONE REVENUE FROM POSTPONING RATE IMPLEMENTATION

In the EB-2019-0045 Decision and Rate Order, the Board approved new electricity distribution rates for Remotes with an effective date of May 1, 2020. In consideration of the COVID-19 emergency, the Board also granted Remotes the option to postpone implementation of its new rates, and to track temporarily forgone revenue in a deferral and variance account.[1]

On April 20, 2020, Remotes filed a letter with the Board, advising that the utility had elected to postpone the implementation of its new rates. In support of this request, and in accordance with the Board's prior instructions in this proceeding, Remotes filed a COVID-19 Forgone Revenue Rate Rider Model in September 2020.

In the EB-2019-0045 Final Rate Order, the Board authorized Remotes to implement its new rates on November 1, 2020, including a rate rider for the recovery of forgone revenues from postponing rate implementation in response to COVID-19 in the amount of $179k over a six-month period. The rider was effective until April 20, 2021.[2]

---

[1] Decision and Rate Order, EB-2019-0045, Hydro One Remote Communities Inc, Application for Rates and Other Charges to be effective May 1, 2020, April 16, 2020, p.6.

[2] Final Rate Order, EB-2019-0045, Hydro One Remote Communities Inc, Final Rate Order for Rates and Other Charges to be effective May 1, 2020 and implemented November 1, 2020, October 8, 2020, p.1.

There is a resulting residual credit balance in this account (as noted in Table 1 and further described in Table 2 below) representing the difference between the forecast upon which the forgone revenue rider was derived and the actual revenue over that period.

Table 2 - Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation Continuity Schedule (*in thousands, $*)

	2020	**2021**
Opening balance	179[1]	120
Amounts recovered through Rate Rider	(59)	(130)
Ending balance	**120**	**(10)**

Note 1: Opening balance as of November 1, 2020

No interest was applied to the rate rider account given Remotes' break-even cost structure, the circular impact of interest and its related impact to RRRP.

2.0 REQUEST FOR DISPOSITION OF ACCOUNTS

It is requested that Remotes' new rates will be effective and implemented on May 1, 2023, and that disposition of the accounts requested will commence on that date.

For the RRRPVA, Remotes is proposing that the RRRP[3] be adjusted upwards by $1,946k annually (representing one-fifth of the 2021 year-end audited balance of $9,732k as noted in Table 1 above) to recover the current RRRPVA balance over the five-year period. This method is proposed to smooth the required RRRP going forward and avoid the one-time rate shock to RRRP that would occur by requesting recovery of the full amount effective in 2023.

For the Rate Rider for Recovery of COVID-19 Forgone Revenues from Postponing Rate Implementation, Remotes is proposing immediate settlement direct to RRRP in 2023 of the residual credit balance of $10k (as noted in Table 1). This is a departure from the Board guidance[4], however this is proposed given the break-even model in which Remotes operates, its approach

[3] Exhibit G, Tab 1, Schedule 1, Table 2.
[4] Filing Requirements for Electricity Distribution Rate Application, Chapter 2, Section 2.9.1.3, April 18, 2022.

to all COVID-19 related costs to date[5], and the non-material nature of the remaining residual account balance.

3.0 ESTABLISHMENT OF NEW DEFERRAL AND VARIANCE ACCOUNTS

Remotes does not require the establishment of any new deferral and/or variance accounts. However, Remotes does seek to continue the RRRPVA to ensure that the business maintains its break-even model.

[5] Exhibit A, Tab 1, Schedule 9.

REMOTES RURAL AND REMOTE RATE PROTECTION VARIANCE ACCOUNT RECONCILIATION 2013 TO 2021

Attachment 1: 2013 to 2017 Rural and Remote Rate Protection Variance Account Reconciliation

Attachment 2: 2018 Rural and Remote Rate Protection Variance Account Reconciliation

Attachment 3: 2019 Rural and Remote Rate Protection Variance Account Reconciliation

Attachment 4: 2020 Rural and Remote Rate Protection Variance Account Reconciliation

Attachment 5: 2021 Rural and Remote Rate Protection Variance Account Reconciliation

Attachment 6: 2018 to 2021 Rural and Remote Rate Protection Variance Account Reconciliation Summary

Attachment 7: 2018 to 2021 Rural and Remote Rate Protection Variance Account Reconciliation Summary (with breakout of Pension Costs and OPEBs)

This page has been left blank intentionally.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2013
For the year ended December 31, 2013
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2013**		**787**		
Annual Rural and Remote Rate Protection		(32,259)		(32,259)	
RRRP Variance Account Recovery		(787)		(787)	
Total RRRP received		**(33,046)**	**(33,046)**	**(33,046)**	
Revenues					
Energy		(14,985)		(17,260)	(2,275)
Other - Late Payment, Service Fees, External		(805)		(586)	219
Total Revenues	**Note 1**	**(15,790)**	**(15,790)**	**(17,846)**	**(2,056)**
Costs - OM&A					
Generation		12,954		10,585	2,369
Fuel		25,568		24,067	1,501
Power purchased		0		1,980	(1,980)
Distribution		1,461		2,980	(1,519)
Customer care		2,844		1,855	989
Community relations		520		750	(230)
Administration and other OM&A		1,439		1,157	282
External costs		206		61	145
Bad debt expense (recovery)		220		48	172
Depreciation		3,153		3,317	(164)
Amortization of environmental assets		1,656		1,861	(205)
Interest		1,104		1,631	(527)
Income taxes		(1,091)		(187)	(904)
Total Costs		**50,034**	**50,034**	**50,105**	**(71)**
Net (Income)/Loss [change in RRRP]		1,198			
RRRP Variance Account, Ending Balance	**31-Dec-2013**		**1,985**		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2013 were $33,046 thousand. An additional $1,198 thousand was recognized as revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2014
For the year ended December 31, 2014
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2014**		**1,985**		
Annual Rural and Remote Rate Protection		(32,259)		(32,259)	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(32,259)**	**(32,259)**	**(32,259)**	
Revenues					
Energy		(16,784)		(17,260)	(476)
Other - Late Payment, Service Fees, External		(494)		(586)	(92)
Total Revenues	**Note 1**	**(17,278)**	**(17,278)**	**(17,846)**	**(568)**
Costs - OM&A					
Generation		14,192		10,585	3,607
Fuel		25,869		24,067	1,802
Power purchased		0		1,980	(1,980)
Distribution		1,879		2,980	(1,101)
Customer care		1,906		1,855	51
Community relations		554		750	(196)
Administration and other OM&A		1,542		1,157	385
External costs		172		61	111
Bad debt expense (recovery)	**Note 2**	(175)		48	(223)
Depreciation		3,024		3,317	(293)
Amortization of environmental assets		1,599		1,861	(262)
Interest		1,559		1,631	(72)
Income taxes		10		(187)	197
Total Costs		**52,131**	**52,131**	**50,105**	**2,026**
Net (Income)/Loss [change in RRRP]		2,594			
RRRP Variance Account, Ending Balance	**31-Dec-2014**		**4,579**		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2014 were $32,259 thousand. An additional $2,594 thousand was recognized as revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $175 thousand reflects the impact of lower energy receivables due to successful long term payment arrangements and vigorous residential collections.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2015
For the year ended December 31, 2015
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2015**		**4,579**		
Annual Rural and Remote Rate Protection		(32,259)		(32,259)	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(32,259)**	**(32,259)**	**(32,259)**	
Revenues					
Energy		(16,272)		(17,260)	(988)
Other - Late Payment, Service Fees, External		(1,608)		(586)	1,022
Total Revenues	**Note 1**	**(17,880)**	**(17,880)**	**(17,846)**	**34**
Costs - OM&A					
Generation		12,947		10,585	2,362
Fuel		23,250		24,067	(817)
Power purchased		0		1,980	(1,980)
Distribution		2,415		2,980	(565)
Customer care		1,733		1,855	(122)
Community relations		291		750	(459)
Administration and other OM&A		1,317		1,157	160
External costs		264		61	203
Bad debt expense (recovery)	**Note 2**	(1,105)		48	(1,153)
Depreciation		3,680		3,317	363
Amortization of environmental assets		1,222		1,861	(639)
Interest		1,678		1,631	47
Income taxes		628		(187)	815
Total Costs		**48,320**	**48,320**	**50,105**	**(1,785)**
Net (Income)/Loss [change in RRRP]		(1,819)			
RRRP Variance Account, Ending Balance	**31-Dec-2015**		**2,760**		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2015 were $32,259 thousand. Of that, $30,440 thousand was recognized as revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $1,105 thousand primarily reflects the successful early completion of a long term payment plan.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2016
For the year ended December 31, 2016
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2016**		**2,760**		
Annual Rural and Remote Rate Protection		(32,259)		(32,259)	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(32,259)**	**(32,259)**	**(32,259)**	
Revenues					
Energy		(17,658)		(17,260)	398
Other - Late Payment, Service Fees, External		(1,556)		(586)	970
Total Revenues	**Note 1**	**(19,214)**	**(19,214)**	**(17,846)**	**1,368**
Costs - OM&A					
Generation		13,931		10,585	3,346
Fuel		23,669		24,067	(398)
Power purchased		0		1,980	(1,980)
OESP Payments to IESO		61		0	61
Distribution		1,991		2,980	(989)
Customer care		1,897		1,855	42
Community relations		138		750	(612)
Administration and other OM&A		1,487		1,157	330
External costs		342		61	281
Bad debt expense (recovery)	**Note 2**	(21)		48	(69)
Depreciation		3,371		3,317	54
Amortization of environmental assets		1,247		1,861	(614)
Interest		1,797		1,631	166
Income taxes		447		(187)	634
Total Costs		**50,357**	**50,357**	**50,105**	**252**
Net (Income)/Loss [change in RRRP]		(1,116)			
RRRP Variance Account, Ending Balance	**31-Dec-2016**		**1,644**		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2016 were $32,259 thousand. Of that, $31,143 thousand was recognized as revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $21 thousand reflects the impact of lower energy receivables due to successful long term payment arrangements and vigorous residential collections.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2017
For the year ended December 31, 2017
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	1-Jan-2017		1,644		
CCA not claimed adjustment	**Note 1**		(682)		
RRRP Variance Account, Adjusted Opening Balance	**1-Jan-2017**		**962**		
Annual Rural and Remote Rate Protection		(32,259)		(32,259)	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(32,259)**	**(32,259)**	**(32,259)**	
Revenues					
Energy		(17,439)		(17,260)	179
Other - Late Payment, Service Fees, External		(1,649)		(586)	1,063
Total Revenues	**Note 2**	**(19,088)**	**(19,088)**	**(17,846)**	**1,242**
Costs - OM&A					
Generation		13,512		10,585	2,927
Distribution		1,626		2,980	(1,354)
Customer Care		1,831		1,855	(24)
Community Relations		174		750	(576)
Bad debt expense (recovery)		(64)		48	(112)
Administrative and General Expenses		1,297		1,157	140
External costs		275		61	214
Fuel		25,695		24,067	1,628
Cost of power		57		1,980	(1,923)
Depreciation		3,620		3,317	303
Amortization of environmental assets		1,285		1,861	(576)
Interest		1,829		1,631	198
Gain on asset disposition		0		0	0
Income taxes		466		(187)	653
Total Costs		**51,603**	**51,603**	**50,105**	**1,498**
Net (Income)/Loss [change in RRRP]		256			
RRRP Variance Account, Ending Balance	**31-Dec-2017**		**1,218**		

Note 1 - As a result of the Initial Public Offering (IPO) of Hydro One Limited, Remotes exited the PILs regime, which triggered a deemed disposition of all of its assets at FMV. As a result of the deemed disposition, Remotes was not able to claim the CCA for the January 1 to October 31, 2015 period for tax purposes. This resulted in a reduction of $682k in the RRRP variance account.

Note 2 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the RRRP Variance Account. Remote rate protection amounts received for the year ended December 31, 2017 were $32,259k. An additional $256k was recognized as revenue, consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the RRRP variance account as illustrated in this reconciliation.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2018
For the year ended December 31, 2018
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2018**		**1,218**	**Note 1**	
Annual Rural and Remote Rate Protection		(35,223)		(35,223)	
Subsidy increase deferred	**Note 2**	2,964		0	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(32,259)**	**(32,259)**	**(35,223)**	
Revenues					
Energy		(18,104)		(17,612)	492
Other - Late Payment, Service Fees, External		(1,394)		(999)	395
Total Revenues	**Note 3**	**(19,498)**	**(19,498)**	**(18,611)**	**887**
Costs - OM&A					
Generation		14,080		15,222	(1,142)
Distribution		1,758		2,014	(256)
Customer Care		1,800		2,151	(351)
Community Relations		157		496	(339)
Bad debt expense (recovery)		12		0	12
Administrative and General Expenses		1,212		1,325	(113)
External costs		589		135	454
Fuel		29,406		25,900	3,506
Cost of power		14		0	14
Depreciation		3,319		3,576	(257)
Amortization of environmental assets		942		1,032	(90)
Interest		1,793		2,052	(259)
Gain on asset disposition		0		0	0
Income taxes		(2)		(69)	67
Total Costs		**55,080**	**55,080**	**53,834**	**1,246**
Net (Income)/Loss [change in RRRP]		3,323			
RRRP Variance Account, Ending Balance	**31-Dec-2018**		**4,541**		

Note 1 - In Remotes COS Application (EB-2017-0051) for 2018-22 Rates, the RRRP variance account balance was not cleared due to outstanding questions relating to pension and income tax adjustments resulting from the Initial Public Offering of Hydro One Limited. This issue has been resolved and the opening 2018 balance is $1,218K based on the carryover of the 2017 ending balance outlined in Exhibit H, Tab 2, Schedule 1, Attachment 1.

Note 2 - Starting in 2018, Remotes was to receive RRRP funding of $35,223K as per the EB-2017-0051 rate order. However, the subsidy increase of $2,964K was deferred by the OEB until the following year, thus Remotes only received funding of $32,259K in 2018.

Note 3 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the RRRP Variance Account. Remote rate protection amounts received for the year ended December 31, 2018 were $32,259K (as the subsidy increase of $2,964K was deferred and received in 2019). An additional $3,323K was recognized as revenue, consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the RRRP variance account as illustrated in this reconciliation.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2019
For the year ended December 31, 2019
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2019**		**4,541**		
Annual Rural and Remote Rate Protection		(35,223)		(35,223)	
Subsidy increase deferred	**Note 1**	(2,964)		0	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(38,187)**	**(38,187)**	**(35,223)**	
Revenues					
Energy		(20,876)		(17,612)	3,264
Other - Late Payment, Service Fees, External		(1,240)		(999)	241
Total Revenues	**Note 2**	**(22,116)**	**(22,116)**	**(18,611)**	**3,505**
Costs - OM&A					
Generation		14,546		15,222	676
Distribution		2,078		2,014	(64)
Customer Care		1,860		2,151	291
Community Relations		703		496	(207)
Bad debt expense (recovery)		122		0	(122)
Administrative and General Expenses		1,088		1,325	237
External costs		691		135	(556)
Fuel		30,251		25,900	(4,351)
Cost of power		1,463		0	(1,463)
Depreciation		3,378		3,576	198
Amortization of environmental assets		3,851		1,032	(2,819)
Interest		1,822		2,052	230
Gain on asset disposition				0	0
Income taxes		(2)		(69)	(67)
Total Costs		**61,851**	**61,851**	**53,834**	**(8,017)**
Net (Income)/Loss [change in RRRP]		1,548			
RRRP Variance Account, Ending Balance	**31-Dec-2019**		**6,089**		

Note 1 - Starting in 2018, Remotes was to receive RRRP funding of $35,223K as per the EB-2017-0051 rate order. However, the subsidy increase of $2,964K was deferred by the OEB until 2019, when it was released to Remotes resulting in a total received funding of $38,187K in 2019.

Note 2 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the RRRP Variance Account. Remote rate protection amounts received for the year ended December 31, 2019 were $35,223K plus the amount of $2,964K that was deferred in 2018. An additional $1,548K was recognized as revenue, consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the RRRP variance account as illustrated in this reconciliation.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2020
For the year ended December 31, 2020
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2020**		**6,089**		
Annual Rural and Remote Rate Protection		(35,223)		(35,223)	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(35,223)**	**(35,223)**	**(35,223)**	
Revenues					
Energy		(22,348)		(17,612)	4,736
Other - Late Payment, Service Fees, External		(840)		(999)	(159)
Total Revenues	**Note 1**	**(23,188)**	**(23,188)**	**(18,611)**	**4,577**
Costs - OM&A					
Generation		14,234		15,222	(988)
Distribution		3,075		2,014	1,061
Customer Care		1,563		2,151	(588)
Community Relations		459		496	(37)
Bad debt expense (recovery)		312		0	312
Administrative and General Expenses		1,053		1,325	(272)
External costs		490		135	355
Fuel		29,166		25,900	3,266
Cost of power		1,779		0	1,779
Depreciation		3,109		3,576	(467)
Amortization of environmental assets		870		1,032	(162)
Interest		1,813		2,052	(239)
Gain on asset disposition		0			0
Income taxes		(3)		(69)	66
Total Costs		**57,920**	**57,920**	**53,834**	**4,086**
Net (Income)/Loss [change in RRRP]		(491)			
RRRP Variance Account, Ending Balance	**31-Dec-2020**		**5,598**		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the RRRP Variance Account. Remote rate protection amounts received for the year ended December 31, 2020 were $35,223K. A reduction of revenue of $491K was recognized, consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the RRRP revenue variance account as illustrated in this reconciliation.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2021
For the year ended December 31, 2021
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2021**		**5,598**		
Annual Rural and Remote Rate Protection		(35,223)		(35,223)	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(35,223)**	**(35,223)**	**(35,223)**	
Revenues					
Energy		(22,585)		(17,612)	4,973
Other - Late Payment, Service Fees, External		(1,330)		(999)	331
Total Revenues	**Note 1**	**(23,915)**	**(23,915)**	**(18,611)**	**5,304**
Costs - OM&A					
Generation		14,290		15,222	(932)
Distribution		2,590		2,014	576
Customer Care		1,556		2,151	(595)
Community Relations		407		496	(89)
Bad debt expense (recovery)	**Note 2**	(147)		0	(147)
Administrative and General Expenses		1,179		1,325	(146)
External costs		731		135	596
Fuel		34,481		25,900	8,581
Cost of power		1,584		0	1,584
Depreciation		3,401		3,576	(175)
Amortization of environmental assets		1,435		1,032	403
Interest		1,765		2,052	(287)
Gain on asset disposition					0
Income taxes		0		(69)	69
Total Costs		**63,272**	**63,272**	**53,834**	**9,438**
Net (Income)/Loss [change in RRRP]		4,134			
RRRP Variance Account, Ending Balance	**31-Dec-2021**		**9,732**		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the RRRP Variance Account. Remote rate protection amounts received for the year ended December 31, 2021 were $35,223K. An additional $4,134K was recognized as revenue, consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the RRRP variance account as illustrated in this reconciliation.

Note 2 - Bad debt recovery of $147K reflects the impact of lower energy receivables due to the resumption of residential collection trips.

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation Summary
For the years ended 2018 to 2021
(in $K)

	Approved					Actuals					Variance
	2018	**2019**	**2020**	**2021**	**Total**	**2018**	**2019**	**2020**	**2021**	**Total**	**Total Approved vs Total Actuals**
RRRP Variance Account, Opening Balance	**Note 1**					1,218	4,541	6,089	5,598		
Annual Rural and Remote Rate Protection	(35,223)	(35,223)	(35,223)	(35,223)	(140,892)	(35,223)	(35,223)	(35,223)	(35,223)	(140,892)	0
Subsidy increase deferred	0	0	0	0	0	2,964	(2,964)	0	0	0	0
Total RRRP received	**(35,223)**	**(35,223)**	**(35,223)**	**(35,223)**	**(140,892)**	**(32,259)**	**(38,187)**	**(35,223)**	**(35,223)**	**(140,892)**	**0**
Revenues											
Energy	(17,612)	(17,612)	(17,612)	(17,612)	(70,448)	(18,104)	(20,876)	(22,348)	(22,585)	(83,913)	(13,465)
Other - Late Payment, Service Fees, External	(999)	(999)	(999)	(999)	(3,996)	(1,394)	(1,240)	(840)	(1,330)	(4,804)	(808)
Total Revenues	**(18,611)**	**(18,611)**	**(18,611)**	**(18,611)**	**(74,444)**	**(19,498)**	**(22,116)**	**(23,188)**	**(23,915)**	**(88,717)**	**(14,273)**
Costs - OM&A											
Generation	15,222	15,222	15,222	15,222	60,888	14,080	14,546	14,234	14,290	57,150	(3,738)
Distribution	2,014	2,014	2,014	2,014	8,056	1,758	2,078	3,075	2,590	9,501	1,445
Customer Care	2,151	2,151	2,151	2,151	8,604	1,800	1,860	1,563	1,556	6,779	(1,825)
Community Relations	496	496	496	496	1,984	157	703	459	407	1,726	(258)
Bad debt expense (recovery)	0	0	0	0	0	12	122	312	(147)	299	299
Administrative and General Expenses	1,325	1,325	1,325	1,325	5,300	1,212	1,088	1,053	1,179	4,532	(768)
External costs	135	135	135	135	540	589	691	490	731	2,501	1,961
Fuel	25,900	25,900	25,900	25,900	103,600	29,406	30,251	29,166	34,481	123,304	19,704
Cost of power	0	0	0	0	0	14	1,463	1,779	1,584	4,840	4,840
Depreciation	3,576	3,576	3,576	3,576	14,304	3,319	3,378	3,109	3,401	13,207	(1,097)
Amortization of environmental assets	1,032	1,032	1,032	1,032	4,128	942	3,851	870	1,435	7,098	2,970
Interest	2,052	2,052	2,052	2,052	8,208	1,793	1,822	1,813	1,765	7,193	(1,015)
Gain on asset disposition	0	0	0	0	0	0	0	0	0	0	0
Income taxes	(69)	(69)	(69)	(69)	(276)	(2)	(2)	(3)	0	(7)	269
Total Costs	**53,834**	**53,834**	**53,834**	**53,834**	**215,336**	**55,080**	**61,851**	**57,920**	**63,272**	**238,123**	**22,787**
Net (Income)/Loss [change in RRRP]	0	0	0	0	0	3,323	1,548	(491)	4,134	8,514	8,514
RRRP Variance Account, Ending Balance	**0**	**0**	**0**	**0**		**4,541**	**6,089**	**5,598**	**9,732**		
Exhibit Reference	H-02-01-02	H-02-01-03	H-02-01-04	H-02-01-05		H-02-01-02	H-02-01-03	H-02-01-04	H-02-01-05		

Note 1 - In Remotes COS Application (EB-2017-0051) for 2018-2022 Rates, the RRRPVA 2016 audited balance of $1644K was not cleared due to outstanding questions related to pension and income tax adjustments resulting from the Initial Public Offering of Hydro One Limited. This issue has been resolved, and resulted in a reduction of $682K in the RRRPVA for an opening 2017 balance of $962K (as documented in Exhibit H, Tab 2, Schedule 1, Attachment 1). With actual costs exceeding revenue by $256K in 2017, the resulting opening 2018 balance is $1,218K (as noted above).

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation Summary (with breakout of Pension Costs and OPEBs)
For the years ended 2018 to 2021
(in $K)

	Approved					Actuals					Variance
	2018	**2019**	**2020**	**2021**	**Total**	**2018**	**2019**	**2020**	**2021**	**Total**	**Total Approved vs Total Actuals**
RRRP Variance Account, Opening Balance	**Note 1**					1,218	4,541	6,089	5,598		
Annual Rural and Remote Rate Protection	(35,223)	(35,223)	(35,223)	(35,223)	(140,892)	(35,223)	(35,223)	(35,223)	(35,223)	(140,892)	0
Subsidy increase deferred	0	0	0	0	0	2,964	(2,964)	0	0	0	0
Total RRRP received	**(35,223)**	**(35,223)**	**(35,223)**	**(35,223)**	**(140,892)**	**(32,259)**	**(38,187)**	**(35,223)**	**(35,223)**	**(140,892)**	**0**
Revenues											
Energy	(17,612)	(17,612)	(17,612)	(17,612)	(70,448)	(18,104)	(20,876)	(22,348)	(22,585)	(83,913)	(13,465)
Other - Late Payment, Service Fees, External	(999)	(999)	(999)	(999)	(3,996)	(1,394)	(1,240)	(840)	(1,330)	(4,804)	(808)
Total Revenues	**(18,611)**	**(18,611)**	**(18,611)**	**(18,611)**	**(74,444)**	**(19,498)**	**(22,116)**	**(23,188)**	**(23,915)**	**(88,717)**	**(14,273)**
Costs - OM&A											
OM&A - Pension Costs **(Note 2)**	687	687	687	687	2,748	543	427	486	465	1,921	(827)
OM&A - OPEBs **(Note 2)**	909	909	909	909	3,636	813	945	1,308	997	4,063	427
OM&A - Other	19,747	19,747	19,747	19,747	78,988	18,252	19,716	19,392	19,144	76,504	(2,484)
Fuel	25,900	25,900	25,900	25,900	103,600	29,406	30,251	29,166	34,481	123,304	19,704
Cost of power	0	0	0	0	0	14	1,463	1,779	1,584	4,840	4,840
Depreciation - Pension Costs	42	42	42	42	168	18	21	17	20	76	(92)
Depreciation - OPEBs	31	31	31	31	124	26	45	22	26	119	(5)
Depreciation - Other	3,503	3,503	3,503	3,503	14,012	3,275	3,312	3,070	3,355	13,012	(1,000)
Amortization of environmental assets	1,032	1,032	1,032	1,032	4,128	942	3,851	870	1,435	7,098	2,970
Interest	2,052	2,052	2,052	2,052	8,208	1,793	1,822	1,813	1,765	7,193	(1,015)
Gain on asset disposition	0	0	0	0	0	0	0	0	0	0	0
Income taxes	(69)	(69)	(69)	(69)	(276)	(2)	(2)	(3)	0	(7)	269
Total Costs	**53,834**	**53,834**	**53,834**	**53,834**	**215,336**	**55,080**	**61,851**	**57,920**	**63,272**	**238,123**	**22,787**
Net (Income)/Loss [change in RRRP]	0	0	0	0	0	3,323	1,548	(491)	4,134	8,514	8,514
RRRP Variance Account, Ending Balance	**0**	**0**	**0**	**0**		**4,541**	**6,089**	**5,598**	**9,732**		

Note 1 - In Remotes COS Application (EB-2017-0051) for 2018-2022 Rates, the RRRPVA 2016 audited balance of $1644K was not cleared due to outstanding questions related to pension and income tax adjustments resulting from the Initial Public Offering of Hydro One Limited. This issue has been resolved, and resulted in a reduction of $682K in the RRRPVA for an opening 2017 balance of $962K (as documented in Exhibit H, Tab 2, Schedule 1, Attachment 1). With actual costs exceeding revenue by $256K in 2017, the resulting opening 2018 balance is $1,218K (as noted above).
Note 2 - Refer to Exhibit D-04-01

HYDRO ONE REMOTES COMMUNITIES INC

Rural and Remote Rate Protection Variance Account Reconciliation 2018
(with breakout of Pension Costs and OPEBs)
For the year ended December 31, 2018
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2018**		**1,218**	**Note 1**	
Annual Rural and Remote Rate Protection		(35,223)		(35,223)	
Subsidy increase deferred	**Note 2**	2,964		0	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(32,259)**	**(32,259)**	**(35,223)**	
Revenues					
Energy		(18,104)		(17,612)	492
Other - Late Payment, Service Fees, External		(1,394)		(999)	395
Total Revenues	**Note 3**	**(19,498)**	**(19,498)**	**(18,611)**	**887**
Costs - OM&A					
OM&A - Pension Costs	**Note 4**	543		687	(144)
OM&A - OPEBs	**Note 4**	813		909	(96)
OM&A - Other		18,252		19,747	(1,495)
Fuel		29,406		25,900	3,506
Cost of power		14		0	14
Depreciation - Pension Costs		18		42	(24)
Depreciation - OPEBs		26		31	(5)
Depreciation - Other		3,275		3,503	(228)
Amortization of environmental assets		942		1,032	(90)
Interest		1,793		2,052	(259)
Gain on asset disposition		0		0	0
Income taxes		(2)		(69)	67
Total Costs		**55,080**	**55,080**	**53,834**	**1,246**
Net (Income)/Loss [change in RRRP]		3,323			
RRRP Variance Account, Ending Balance	**31-Dec-2018**		**4,541**		

Note 1 - In Remotes COS Application (EB-2017-0051) for 2018-22 Rates, the RRRP variance account balance was not cleared due to outstanding questions relating to pension and income tax adjustments resulting from the Initial Public Offering of Hydro One Limited. This issue has been resolved and the opening 2018 balance is $1,218k based on the carryover of the 2017 ending balance outlined in Exhibit H, Tab 2, Schedule 1, Attachment 1.

Note 2 - Starting in 2018, Remotes was to receive RRRP funding of $35,223k as per the EB-2017-0051 rate order. However, the subsidy increase of $2,964k was deferred by the OEB until the following year, thus Remotes only received funding of $32,259k in 2018.

Note 3 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the RRRP Variance Account. Remote rate protection amounts received for the year ended December 31, 2018 were $32,259k (as the subsidy increase of $2,964k was deferred and received in 2019). An additional $3,323k was recognized as revenue, consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the RRRP variance account as illustrated in this reconciliation.

Note 4 - Refer to Exhibit D-04-01

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2019
(with breakout of Pension Costs and OPEBs)
For the year ended December 31, 2019
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2019**		**4,541**		
Annual Rural and Remote Rate Protection		(35,223)		(35,223)	
Subsidy increase deferred	**Note 1**	(2,964)		0	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(38,187)**	**(38,187)**	**(35,223)**	
Revenues					
Energy		(20,876)		(17,612)	3,264
Other - Late Payment, Service Fees, External		(1,240)		(999)	241
Total Revenues	**Note 2**	**(22,116)**	**(22,116)**	**(18,611)**	**3,505**
Costs - OM&A					
OM&A - Pension Costs	**Note 3**	427		687	260
OM&A - OPEBs	**Note 3**	945		909	(36)
OM&A - Other		19,716		19,747	31
Fuel		30,251		25,900	(4,351)
Cost of power		1,463		0	(1,463)
Depreciation - Pension Costs		21		42	21
Depreciation - OPEBs		45		31	(14)
Depreciation - Other		3,312		3,503	191
Amortization of environmental assets		3,851		1,032	(2,819)
Interest		1,822		2,052	230
Gain on asset disposition		0		0	0
Income taxes		(2)		(69)	(67)
Total Costs		**61,851**	**61,851**	**53,834**	**(8,017)**
Net (Income)/Loss [change in RRRP]		1,548			
RRRP Variance Account, Ending Balance	**31-Dec-2019**		**6,089**		

Note 1 - Starting in 2018, Remotes was to receive RRRP funding of $35,223k as per the EB-2017-0051 rate order. However, the subsidy increase of $2,964k was deferred by the OEB until 2019, when it was released to Remotes resulting in a total received funding of $38,187k in 2019.

Note 2 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the RRRP Variance Account. Remote rate protection amounts received for the year ended December 31, 2019 were $35,223k plus the amount of $2,964k that was deferred in 2018. An additional $1,548k was recognized as revenue, consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the RRRP variance account as illustrated in this reconciliation.

Note 3 - Refer to Exhibit D-04-01

HYDRO ONE REMOTES COMMUNITIES INC

Rural and Remote Rate Protection Variance Account Reconciliation 2020
(with breakout of Pension Costs and OPEBs)
For the year ended December 31, 2020
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2020**		**6,089**		
Annual Rural and Remote Rate Protection		(35,223)		(35,223)	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(35,223)**	**(35,223)**	**(35,223)**	
Revenues					
Energy		(22,348)		(17,612)	4,736
Other - Late Payment, Service Fees, External		(840)		(999)	(159)
Total Revenues	**Note 1**	**(23,188)**	**(23,188)**	**(18,611)**	**4,577**
Costs - OM&A					
OM&A - Pension Costs	**Note 2**	486		687	(201)
OM&A - OPEBs	**Note 2**	1,308		909	399
OM&A - Other		19,392		19,747	(355)
Fuel		29,166		25,900	3,266
Cost of power		1,779		-	1,779
Depreciation - Pension Costs		17		42	(25)
Depreciation - OPEBs		22		31	(9)
Depreciation - Other		3,070		3,503	(433)
Amortization of environmental assets		870		1,032	(162)
Interest		1,813		2,052	(239)
Gain on asset disposition		0		-	0
Income taxes		(3)		(69)	66
Total Costs		**57,920**	**57,920**	**53,834**	**4,086**
Net (Income)/Loss [change in RRRP]		(491)			
RRRP Variance Account, Ending Balance	**31-Dec-2020**		**5,598**		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the RRRP Variance Account. Remote rate protection amounts received for the year ended December 31, 2020 were $35,223k. A reduction of revenue of $491k was recognized, consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the RRRP revenue variance account as illustrated in this reconciliation.

Note 2 - Refer to Exhibit D-04-01

HYDRO ONE REMOTES COMMUNITIES INC
Rural and Remote Rate Protection Variance Account Reconciliation 2021
(with breakout of Pension Costs and OPEBs)
For the year ended December 31, 2021
(in $K)

		Actual Revenues and Expenses (Audited)		Approved	Variance
RRRP Variance Account, Opening Balance	**1-Jan-2021**		**5,598**		
Annual Rural and Remote Rate Protection		(35,223)		(35,223)	
RRRP Variance Account Recovery		0		0	
Total RRRP received		**(35,223)**	**(35,223)**	**(35,223)**	
Revenues					
Energy		(22,585)		(17,612)	4,973
Other - Late Payment, Service Fees, External		(1,330)		(999)	331
Total Revenues	**Note 1**	**(23,915)**	**(23,915)**	**(18,611)**	**5,304**
Costs - OM&A					
OM&A - Pension Costs	**Note 2**	465		687	(222)
OM&A - OPEBs	**Note 2**	997		909	88
OM&A - Other		19,144		19,747	(603)
Fuel		34,481		25,900	8,581
Cost of power		1,584		0	1,584
Depreciation - Pension Costs		20		42	(22)
Depreciation - OPEBs		26		31	(5)
Depreciation - Other		3,355		3,503	(148)
Amortization of environmental assets		1,435		1,032	403
Interest		1,765		2,052	(287)
Gain on asset disposition		0		0	0
Income taxes		0		(69)	69
Total Costs		**63,272**	**63,272**	**53,834**	**9,438**
Net (Income)/Loss [change in RRRP]		4,134			
RRRP Variance Account, Ending Balance	**31-Dec-2021**		**9,732**		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the RRRP Variance Account. Remote rate protection amounts received for the year ended December 31, 2021 were $35,223k. An additional $4,134k was recognized as revenue, consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the RRRP variance account as illustrated in this reconciliation.

Note 2 - Refer to Exhibit D-04-01